CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

THE OIL SANDS DEVELOPERS GROUP
Energy From Athabasca

GUIDE

Water Conservation, Efficiency and Productivity Plan –

Upstream Oil and Gas Sector

March 2011

2010-0026

The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and crude oil throughout Canada. CAPP's member companies produce more than 90 per cent of Canada's natural gas and crude oil. CAPP's associate members provide a wide range of services that support the upstream crude oil and natural gas industry. Together CAPP's members and associate members are an important part of a national industry with revenues of about $100 billion-a-year. CAPP's mission is to enhance the economic sustainability of the Canadian upstream petroleum industry in a safe and environmentally and socially responsible manner, through constructive engagement and communication with governments, the public and stakeholders in the communities in which we operate.

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Disclaimer

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1 Overview of CEP Sector Plan

1.1 Goals and Objectives of CEP Sector Plan

Goals and objectives

The purpose of this document is to provide sector-specific information related to water Conservation, Efficiency and Productivity (CEP), the three parameters used by the Alberta Water Council to guide efforts to improve water use in Alberta. The Alberta Water Council (2006) defines these parameters as follows:

- **Conservation** refers to any beneficial reduction in water use, loss or waste, or practices that improve the use of water to benefit people or the environment.
- **Efficiency** refers to the accomplishment of a function, task, process or result with the minimal amount of water feasible. Efficiency is an indicator of the relationship between the amount of water required for a particular purpose and the quantity of water used or diverted.
- **Productivity** refers to the amount of non-saline water required to produce a unit of any good, service, or societal value.

The Alberta Water Council recommended the development of publicly-available CEP plans for seven major water-using sectors: chemical and petrochemical; irrigation; forestry; mining and oil sands; urban municipalities; oil and gas; and power generation. This document fulfills the Alberta Water Council's request for CEP plans from two industry sectors: the upstream oil and gas component of the oil and gas sector; and the oil sands component of the mining and oil sands sector. For simplicity, the two sub-sectors will be collectively referred to throughout this document as "the upstream oil and gas sector."

The Alberta Water Council expected that sector CEP plans would promote management practices to conserve water, in part by using water more efficiently and productively. Accordingly, this plan promotes the use of less water to achieve similar economic productivity, thus redistributing water for use in achieving other environmental, social, and economic benefits. The focus is on water quantity; although water quality is also important, it is outside the scope of this plan.

This CEP plan addresses the Alberta Water Council's recommendations by:

- Providing factual information regarding historical water use and current projections for future water use;
- Demonstrating industry best management practices related to water management;
- Identifying practical opportunities for future water use efficiencies; and
- Identifying potential measures that may contribute to Alberta's goal of a 30% improvement in overall water efficiency and productivity from 2005 levels by 2015.

Future vision

The upstream oil and gas sector is committed to responsible water use. The sector anticipates future water uses that provide cost-effective economic value to society derived from the direct utilization of water, balanced with environmental and social values. In many cases, this economic value may be increased by CEP initiatives. At the same time, industry will continue its collective commitment to meet the regulatory requirements that influence or limit the use of water.

Water for Life

Water for Life: Alberta's Strategy for Sustainability (Alberta Environment, 2003a) is principled on Albertans becoming leaders at using water more effectively and efficiently. The industry members associated with this CEP plan support this important principle to address current and future water scarcity and its potential limitations on benefits to Alberta residents. The upstream oil and gas sector continually examines options to use water more effectively, and has demonstrated its commitment to this principle by supporting a number of ongoing research projects (see Section 2.4).

The *Water for Life* strategy includes three specific goals:

- Safe, secure drinking water supply;
- Healthy aquatic ecosystems; and
- Reliable, quality water supplies for a sustainable economy.

These goals will be met through:

- Knowledge and research;
- Partnerships; and
- Water conservation.

A specific outcome of the *Water for Life* strategy relating to water conservation is: "Demonstration in all sectors of best management practices, ensuring overall efficiency and productivity of water use in Alberta improves by 30% from 2005 levels by 2015. This will occur when either demand for water is reduced or water use efficiency and productivity are increased." (Alberta Environment, 2008b). Due to the projected water-assisted growth in the upstream oil and gas sector, the focus of this sector plan is on increasing non-saline water use productivity rather than reducing absolute water demand.

The 30% target applies to the aggregate of all water users in Alberta and was not intended to be an absolute target for each sector. This sector plan was developed with the overall provincial target in mind.

CEP goals

This CEP plan supports the *Water for Life* strategy by documenting ongoing improvements and by identifying potential CEP initiatives for operators to consider. CEP initiatives will vary based on local conditions and industry uses, but are expected to include:

- Use of alternative water sources, such as sources with relatively poor water quality;
- Redistribution of water use, if possible, away from areas where available water is relatively scarce;
- Reuse of water to avoid withdrawing additional water;
- Adoption of technologies, if possible, that reduce the amount of water required;

- Collaboration among producers to promote water use efficiencies that are not otherwise available to individual producers;
- Communication with stakeholders to discuss the options and limitations of water use by the upstream oil and gas sector; and
- Participation in regional water stewardship activities.

1.2 Scope of Plan

This plan reports on the historical and projected water use by the upstream oil and gas sector. It also describes current initiatives and potential opportunities to reduce future water use, several of which appear to be promising for the industry as a whole. The CEP plan is intended for use in areas of Alberta with upstream oil and gas sector activity; however, local conditions will dictate which measures are ultimately implemented.

This CEP plan applies to water use by the following industries:

- Oil sands mining bitumen production;
- Oil sands in situ bitumen production, including thermal production and other primary or enhanced production methods in the oil sands region of northern Alberta;
- Conventional oil production, including light, medium, and heavy oil production;
- Drilling and completion of upstream oil and gas wells; and
- Gas plants.

It does not apply to water use by midstream (i.e., processing, storage and transportation) or downstream (i.e., refining and marketing) oil and gas activities. Shale gas water use was also excluded from the CEP plan since commercial production is not currently projected to occur in Alberta until after 2015, which is beyond the scope of this CEP plan as defined by the *Recommendations for Water Conservation, Efficiency and Productivity Sector Planning* (Alberta Water Council, 2008). In recognition of the early stage of shale gas development in Alberta, strategies for management of water required for shale gas development are in the process of being developed and will be incorporated into future plan updates.

The plan focuses on volumes of water diverted and on major water uses. Return flows to the environment are not discussed, as recent information has shown that the volume of non-saline water produced by the oil and gas industry is limited (ERCB, 2009). Non-consumptive water diversions are also not included, such as the dewatering of surface area for oil sands mines and similar activities.

All information used to prepare this plan is publicly available; key data sources are listed below:

- Oil and bitumen production information from 2005 through forecast production to 2015 provided by the *2010 – 2025 Canadian Crude Oil Forecast and Market Outlook* (CAPP, June 2010);
- Oil and bitumen production information from 2000 through 2004 from the ERCB ST98 report (ERCB, 2009);

- Oil production information for enhanced oil recovery (EOR) methods, available through the Petroleum Registry of Alberta;
- Gas production information available through the Petroleum Registry of Alberta;
- Oil sands mining water use from 2000 to 2009 available through Alberta Environment;
- Oil sands in situ water use from 2002 to 2009 available through Alberta Environment, based on information collected and managed through the Petroleum Registry of Alberta;
- Conventional oil water use from 2000 to 2009, based on Alberta Environment database queries;
- Gas plant water use from 2005 to 2008, based on Alberta Environment database queries;
- Drilling activity from 2000 to 2009, based on the ERCB ST98 report (ERCB, 2009); and
- Drilling water use per well based on assumed typical industry rates.

This document is organized in accordance with the Alberta Water Council's recommendations for water CEP sector plans.

1.3 The Case for Water CEP

Benefits

The CEP plan is expected to help provide several benefits:

- Potential industry water savings and corresponding net economic benefits for producers by avoiding water costs, depending on the required additional infrastructure capital and operating costs;
- Potential for improved water security based on reduced likelihood of exceeding water licence limits;
- Potential for economic expansion within existing water licences, due to improved water management practices;
- Opportunity to collaborate as a good environmental steward of provincial water resources;
- Opportunity to share factual information with the public; and
- Potential improved information base for regional watershed management and water allocation.

Risks

The risks associated with not improving industry water CEP include:

- Persistence of negative stakeholder perceptions;
- Uneconomic use of water;
- Unbalanced allocation of water in terms of social, environmental, and economic benefits; and
- Loss of economic opportunities for both the sector and the Province.

Stakeholders

External stakeholders that could potentially benefit from this CEP plan ultimately comprise the province and population of Alberta, with the direct benefit being the economic success of companies demonstrating sustainable and prudent water management. Specific external stakeholders include:

- The Government of Alberta;
- Alberta Water Council;
- Watershed Planning and Advisory Councils (WPACs);
- First Nations and Métis populations;
- Urban and rural municipalities whose drinking water sources are in watersheds where industry is located;
- Rural water users, such as farmers; and
- Other commercial and industrial water users.

1.4 CEP Plan Champion and Leaders

The industry members participating in this plan include oil and gas producers and service companies for drilling and completions, all of which contribute to the overall water footprint of the sector. The following associations and organizations are represented:

- Canadian Association of Petroleum Producers (CAPP) – represents large and small oil and gas companies; and
- Oil Sands Developers Group (OSDG) – represents oil sands operators and developers.

CAPP is ultimately responsible for the development, approval, implementation and renewal of the CEP plan on behalf of the upstream oil and gas sector. CAPP’s member companies produce about 90% of Canada’s crude oil and natural gas, including oil sands mining and in situ production, conventional oil, and natural gas (conventional gas production, plus coalbed methane, deep gas, tight gas, and shale gas). OSDG also has a leadership role in developing and implementing CEP opportunities recommended in this plan.

This CEP plan was prepared by members of CAPP and OSDG with assistance from Golder Associates Ltd. and Geowa Information Technologies Ltd. A complete list of contributors is provided in the Acknowledgements.

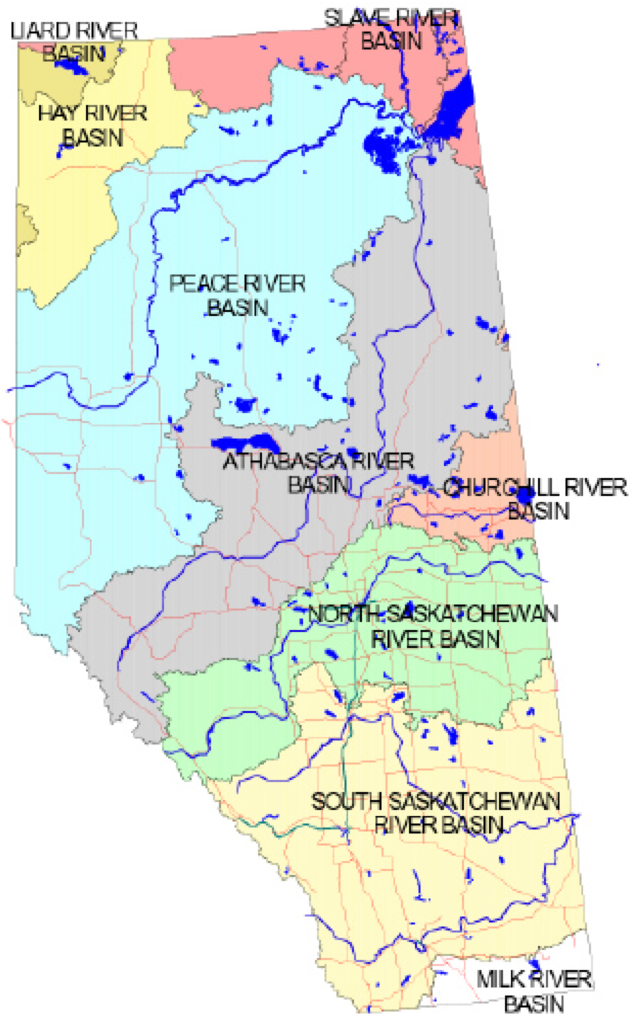
2 Profile of Existing Water Systems

2.1 Water Use Profile

2.1.1 Physical Characteristics

Geographical area

Water use by the upstream oil and gas industry occurs in each of the seven major river basins in Alberta, namely, the Peace, Athabasca, Hay/Liard, North Saskatchewan, South Saskatchewan, Beaver/Churchill, and Milk River basins (Figure 2-1).



Source: Alberta Environment website

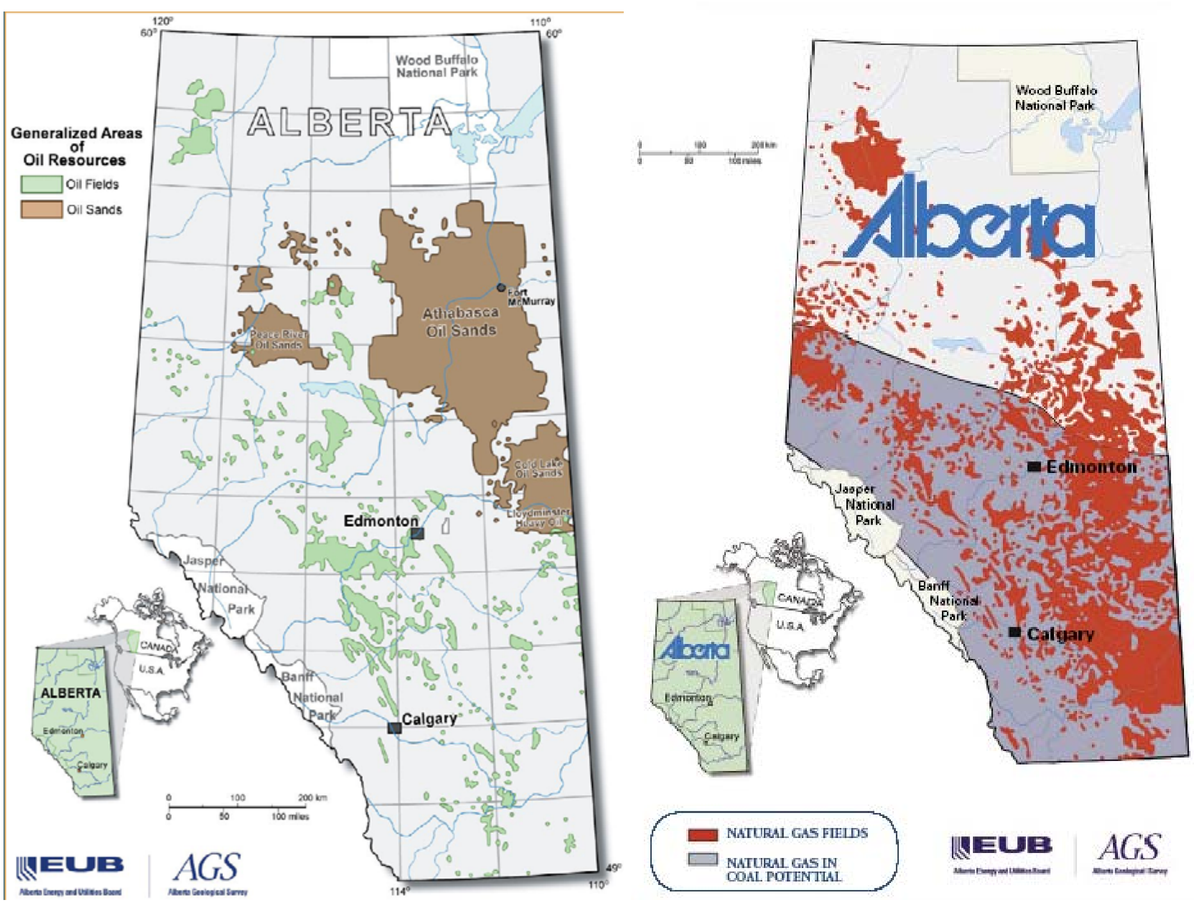
Figure 2-1: Alberta River Basins

Infrastructure locations

Water is used for the following types of resource development in the upstream oil and gas sector:

- Oil sands mining;
- Oil sands in situ thermal, cold flow and various primary or enhanced production operations;
- Conventional oil;
- Natural gas production and processing; and
- Unconventional oil and gas, such as coalbed methane (CBM) and potential future shale gas developments.

The distribution of bitumen and oil and gas production in Alberta is shown in Figure 2-2. Conventional oil deposits have been discovered across the province, but the main fields are located between Calgary and Edmonton. Alberta has three main areas of oil sands deposits: the largest is the Athabasca deposit near Fort McMurray, with two other deposits located near Peace River and Cold Lake. Known fields of natural gas from conventional and unconventional sources are distributed across a much wider area of the province.



Source: ERCB 2007, http://www.energy.alberta.ca/Oil/pdfs/oil_resources_Map.pdf

Figure 2-2: Location of Alberta Oil and Gas Resources (2007)

2.1.2 Baseline Water Use

Water licence conditions

The *Water Resources Act* of 1931 was based on a first-in-time, first-in-right (FITFIR) priority system designed to promote new development and protect existing development. These licences typically did not have an expiry date. In 1999, this Act was replaced by the *Water Act*, which was designed to promote water conservation while recognizing the need for economic growth and prosperity.

Under the *Water Act*, a licence is required to divert large volumes of surface water from rivers, lakes and ponds, and non-saline groundwater from underground aquifers. Small volumes and some private or municipal use of water is exempt from licensing. Saline groundwater use is also not licenced.

The *Water Act* defines saline groundwater as that containing greater than 4000 milligrams per litre (mg/L) total dissolved solids (TDS). This water is not considered suitable for drinking or agriculture. Groundwater containing 4000 mg/L TDS or less is described as non-saline. The upstream oil and gas sector obtains a significant portion of water for waterflooding and steam generation for in situ oil sands operations from deep saline groundwater sources that are generally considered unusable by other industries or sectors.

The non-saline categorization of some water should not be confused with water used for potable supply. Health Canada defines potable water (water suitable for human consumption) as containing less than 500 mg/L TDS (Health Canada, 1978). Potable water is also subject to regulations for water treatment and distribution, regardless of the source (surface water or groundwater).

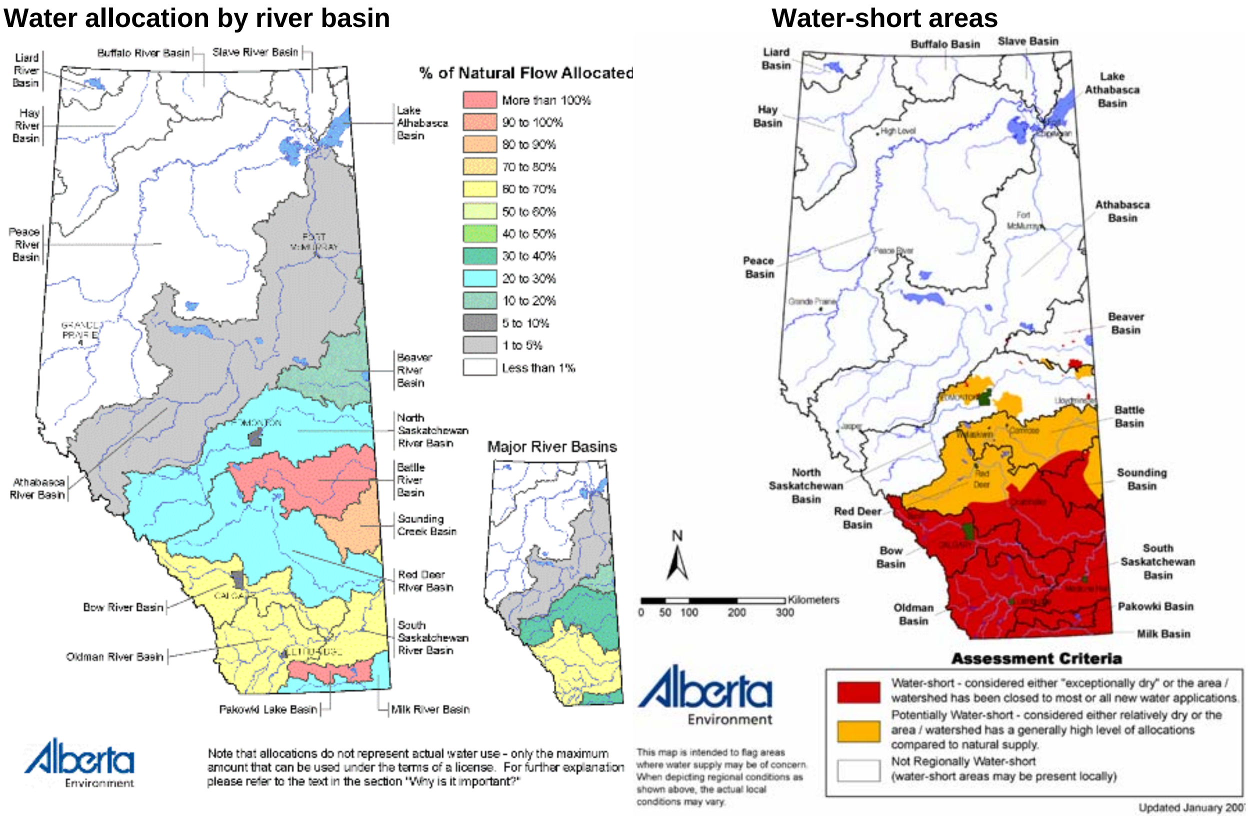
Water licences granted in Alberta after 1999 all have expiry dates. This shift in the regulatory context for water management is also reflected in the adoption of *Water for Life: Alberta's Strategy for Sustainability* (Alberta Environment, 2003a) as policy for water management in Alberta. Typically, a new water licence will expire after five or ten years and must be renewed. Other temporary diversion licences (TDLs) can range from weeks to a year, with an option to extend for up to one additional year. Some older licences issued under the *Water Resources Act* still exist without expiry.

Water licences typically limit the maximum annual volume and the instantaneous peak rate, as well as having other site-specific conditions. Some licences also specify a return flow that must be discharged back to the environment. The licenced amount that an applicant is permitted to extract is a maximum volume.

Under the *Water Act*, all licensees must retain records of water use. Most municipal, irrigation, and large commercial and industrial users are required to report their actual water use. Alberta Environment has developed an online reporting system to obtain water use information in a more efficient manner.

There are provisions under the *Water Act* to refer an application for review under the *Environmental Protection and Enhancement Act* (EPEA). Also, compliance with certain sections of the EPEA is mandatory for issue or amendment of an approval or licence under the *Water Act*.

The relative availability of water throughout the province depends on both the amount of water yield available and the amount of water that is allocated for use. Overall, the northern portions of Alberta have high supply and low demand, while higher percentages of the natural flow are allocated in southern regions. This is illustrated in Figure 2-3.



Source: Alberta Environment, 2006a

Figure 2-3: Distribution of Water Allocation (2006)

Water availability is described in *Water Supply Assessment for Alberta* (Golder Associates, 2008) and in the Alberta Environment report *Water-short Areas Assessment* (Alberta Environment, 2006a). To identify water-short areas in Alberta, Alberta Environment (2006a) defined three categories of areas:

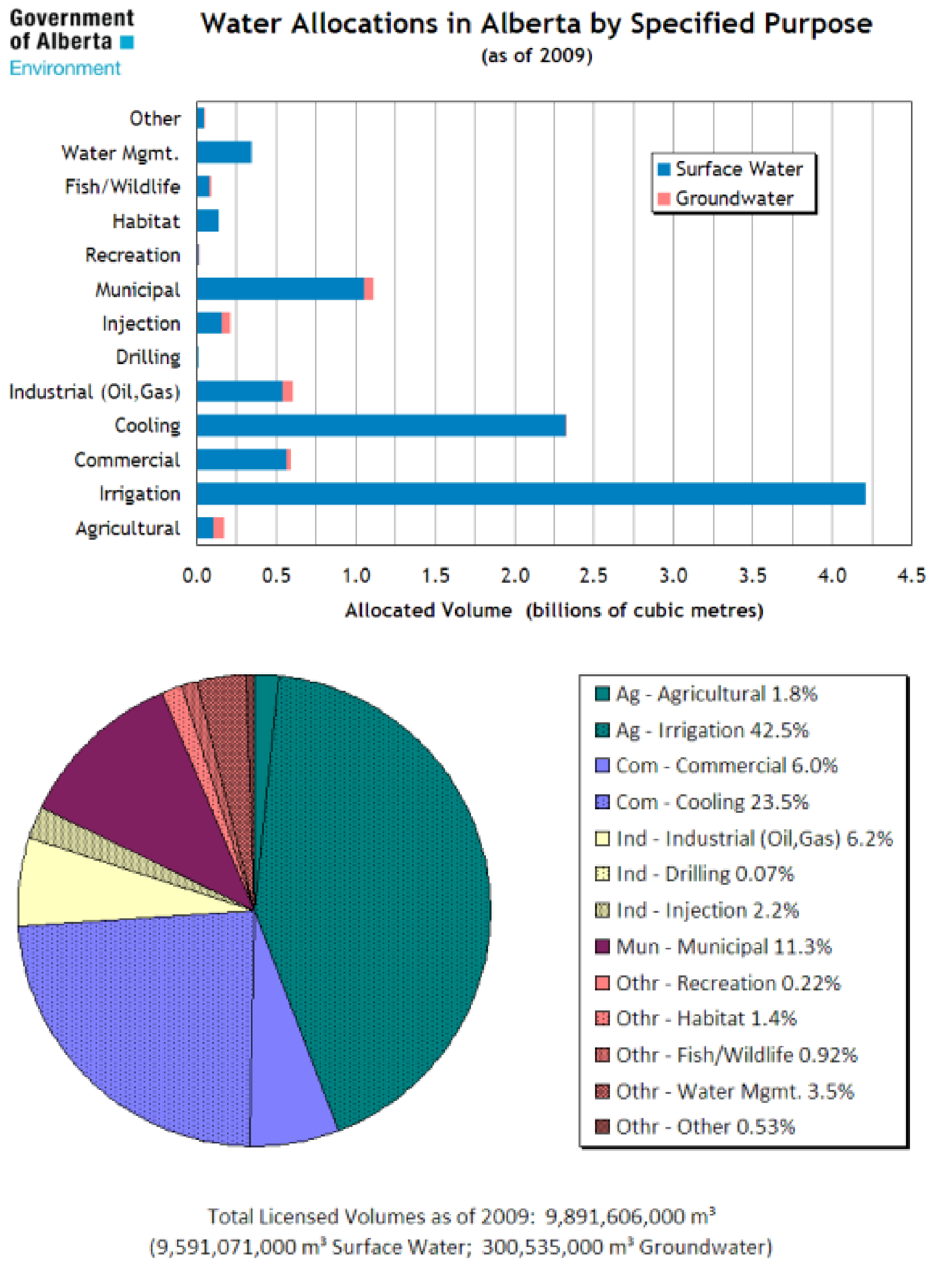
- Water-short: considered either exceptionally dry, or the area/watershed has been closed to most or all new water applications;
- Potentially water-short: considered either relatively dry, or the area/watershed has a generally high level of allocations compared to natural supply; and
- Not regionally water-short: areas that are not observed as regionally water-short, but some water-short areas may be present locally.

The water-short areas are situated primarily in the South Saskatchewan River Basin (SSRB), which includes the Bow River, Oldman River, Red Deer River, and South Saskatchewan River sub-basins. With the exception of the Red Deer River sub-basin, the SSRB was closed to new surface water licences in 2006 (Alberta Environment, 2006b).

The *Water Act* provides the ability to transfer an allocation of water under a licence to another user. Water allocation transfers provide a means for enterprises that require new, additional, or more reliable water allocations to secure such allocations from existing licence holders through a private arrangement. Implications for other licence holders and the aquatic environment are considered and Alberta Environment approval of the transfer is required. The long-term target for the water market is for water allocation to shift to the most beneficial water uses. Transfers are expected to provide a financial incentive to existing licence holders to increase water use efficiency so that surplus water can be marketed (Government of Alberta, 2009).

Water allocation

In 2009, Alberta's total water allocation was 9.89 billion m^3, 97% of which was allocated from surface water sources, and the remaining 3% from groundwater sources. The oil and gas sector is the fourth largest water user in Alberta, after irrigation, commercial cooling, and municipalities. As illustrated in Figure 2-4, agriculture and irrigation account for 44.3% of the provincial water allocation; commercial and cooling account for 29.5%; municipal use accounts for 11.3%; and 8.5% is allocated to the oil and gas industry, including oil sands (i.e., industrial, injection and drilling).



Source: Alberta Environment

Figure 2-4: Water Allocation by Sector (2009)

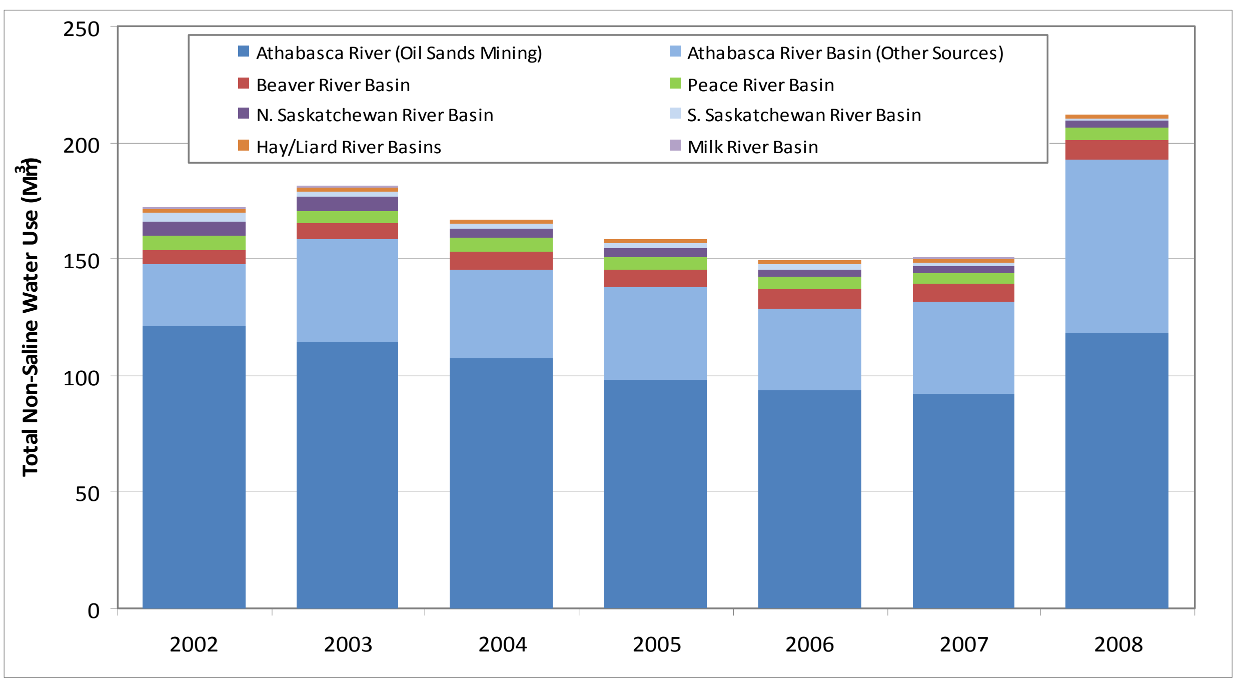
Actual water use

Oil and gas exploration and production in Alberta occurs in all three categories of watersheds: those not regionally water-short, potentially water-short, or water-short. Most of this water use is in the Athabasca River basin, and is dominated by oil sands mining water use.

Non-saline water use by the upstream oil and gas sector for the years 2002 to 2008 was between 149 and 212 million cubic metres per year (Mm^3), or about 25% of allocation (see Figure 2-5). A breakdown of actual water use by river basin and various water sources is presented in Table 2-1. This breakdown was not available for 2009. The relatively large increase in water use from the Athabasca River basin in 2008 that is shown in Figure 2-5 and Table 2-1 was due in part to the startup of mining operations for the Canadian Natural Resources Limited (CNRL) Horizon Project.

The totals in Figure 2-5 and Table 2-1 do not include water used by gas plants or water used for drilling and completions of wells, as this water was available but not broken down by river basin. The estimated provincial total for these additional water uses is:

- Water use by gas plants is about 5.8 Mm^3 per year, based on Alberta Environment information for 2005 to 2008; and
- Water use for drilling and completion of wells includes oil, bitumen, gas and other wells. The average water use was approximately 8.3 Mm^3 per year from 2000 to 2008. This volume is estimated and uncertain because the volumes are typically small and the actual water use for temporary diversion licences is not reported by Alberta Environment or the ERCB. The estimated water use for drilling and completion of wells is between 6.6 Mm^3 and 10 Mm^3 per year, based on 16,600 wells drilled per year, on average, from 2000 to 2008 (ERCB, 2009) and an assumed average water use between 400 m^3 and 600 m^3.



Source: Alberta Environment

Figure 2-5: Non-saline Water Use by River Basin (2002 to 2008)

Table 2-1: Water Use by River Basin (2002 to 2008)

River Basin	Water Source	Water Use (Mm^3)						
		2002	2003	2004	2005	2006	2007	2008
Athabasca River	**Athabasca River (Oil Sands Mining)**	**121.3**	**114.0**	**107.1**	**98.5**	**93.4**	**92.3**	**118.3**
	Other Surface Water	21.7	36.4	30.1	31.7	26.8	27.8	61.6
	Non-saline Groundwater	4.6	8.2	8.5	8.0	8.9	11.5	12.7
	Total Non-saline (excl. Athabasca R.)	**26.2**	**44.6**	**38.6**	**39.6**	**35.7**	**39.4**	**74.3**
	Saline Groundwater	0.9	5.2	11.0	10.7	12.5	14.9	13.6
Beaver River	Surface Water	3.8	3.7	4.0	3.4	4.0	4.1	4.3
	Non-saline Groundwater	2.6	3.0	3.3	3.9	4.4	3.7	4.6
	Total Non-saline Water	**6.5**	**6.7**	**7.3**	**7.4**	**8.3**	**7.8**	**8.8**
	Saline Groundwater	0.1	2.3	2.1	2.9	5.2	6.2	6.9
Peace River	Surface Water	4.7	4.2	4.8	4.1	4.0	3.6	3.6
	Non-saline Groundwater	1.4	1.5	1.4	1.2	1.4	1.3	1.3
	Total Non-saline Water	**6.1**	**5.7**	**6.3**	**5.4**	**5.3**	**4.9**	**4.9**
	Saline Groundwater	2.7	3.4	2.9	2.4	2.0	1.7	1.9
North Saskatchewan River	Surface Water	4.4	4.0	2.8	2.8	2.1	1.7	2.1
	Non-saline Groundwater	2.0	1.6	1.4	1.4	1.0	0.8	0.9
	Total Non-saline Water	**6.4**	**5.6**	**4.2**	**4.2**	**3.1**	**2.5**	**3.0**
	Saline Groundwater	3.8	3.5	3.5	3.5	3.1	3.3	3.2
South Saskatchewan River	Surface Water	2.5	1.6	1.2	1.4	1.3	1.1	0.9
	Non-saline Groundwater	1.3	1.1	0.9	0.6	0.6	0.7	0.4
	Total Non-saline Water	**3.7**	**2.7**	**2.2**	**2.0**	**1.8**	**1.8**	**1.2**
	Saline Groundwater	2.2	1.2	1.1	1.6	1.6	2.0	1.8
Hay/Liard Rivers	Surface Water	1.2	1.4	1.2	1.3	1.4	1.5	1.3
	Non-saline Groundwater	0.1	0.2	0.2	0.2	0.3	0.3	0.02
	Total Non-saline Water	**1.3**	**1.6**	**1.3**	**1.5**	**1.7**	**1.7**	**1.3**
	Saline Groundwater						0.00	0.02
Milk River	Surface Water		0.02	0.02	0.00			
	Non-saline Groundwater		0.01	0.00	0.01			
	Total Non-saline Water		**0.03**	**0.03**	**0.01**			
	Saline Groundwater	0.5	0.3	0.2	0.2	0.3	0.2	0.1
Alberta Total	Athabasca River (Oil Sands Mining)	121.3	114.0	107.1	98.5	93.4	92.3	118.3
	Other Surface Water	38.4	51.2	44.2	44.7	39.4	39.8	73.8
	Non-saline Groundwater	11.9	15.7	15.7	15.4	16.5	18.3	19.9
	Total Non-saline Water	**171.6**	**180.9**	**167.0**	**158.6**	**149.4**	**150.4**	**211.9**
	Saline Groundwater	10.1	15.9	20.8	21.3	24.7	28.3	27.6

Notes:
1. Total non-saline water use for each basin is sum of non-saline groundwater and surface water use.
2. Blank cells indicate no data available, and are likely equal to zero volume.
3. Not including water use by gas plants and well drilling and completions, which were not broken down by basin.

The largest single water use by volume is the oil sands mining withdrawal from the Athabasca River. Each oil sands mine is licenced to divert water for consumptive use from the following sources:

- Direct withdrawal from the Athabasca River;
- Collection of surface runoff from mine areas;
- Collection of groundwater within mine areas; and
- Other water diversion licences for oil sands mines, such as muskeg dewatering and basal aquifer depressurization.

The oil sands mines are approved to withdraw up to 411.7 Mm^3 per year from the Athabasca River, including approved mines that are not yet developed. A summary of the oil sands mining water licences and reported annual usage within the Athabasca River basin is presented in Table 2-2 for 2000 to 2009, including: the direct withdrawal from the Athabasca River; the allocated volume from the Athabasca River; and total non-saline water use including the licenced collection of surface water and groundwater within mine areas.

Actual Athabasca River water withdrawal by oil sands mining was 106.5 Mm^3 in 2009 or 26% of allocation (Alberta Environment, 2010). This withdrawal is equivalent to 3.4 m^3/s or about 0.5% of the 23,500 Mm^3 per year long-term average annual water yield of the Athabasca River basin. The basin water yield estimate was reported by Alberta Environment (Golder Associates, 2008) as an estimate of the natural basin water yield for the Athabasca River at its confluence with Lake Athabasca, based on analyses of upstream gauging station data from 1971 to 2006.

Most of the industry's water use is consumptive with relatively small volumes returned to rivers or aquifers. Therefore, information on return flows was not compiled as part of this report. For the purpose of this CEP plan, water use neglects return flow as an amount of water that would otherwise offset the water diversions.

Table 2-2: Oil Sands Mining Water Use (2000 to 2009)

Year	Athabasca River Withdrawal (Mm^3)		Total [1] Non-saline Water Use (Mm^3)
	Use	Allocation	
2000	82.7	176.6	98.0
2001	93.4	176.6	122.6
2002	121.3	176.6	143.4
2003	114.0	215.9	152.3
2004	107.1	361.7	139.1
2005	98.4	361.7	132.7
2006	93.4	361.7	124.1
2007	92.3	361.7	124.8
2008	118.3	411.7	184.3
2009	106.5	411.7	162.4

Note: [1] Total non-saline water use includes licenced collection of surface water and groundwater within mine areas.
Source: Alberta Environment

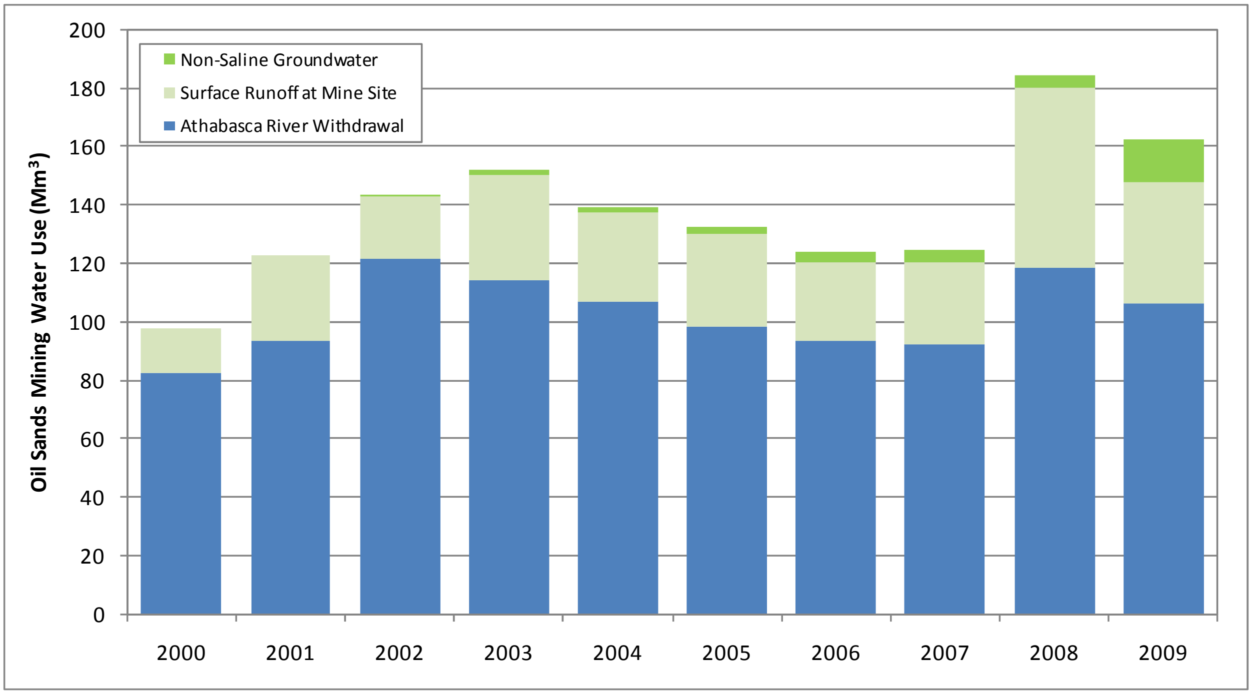
Water sources

Depending on the location and nature of the operation, sector water sources include:

- Surface water, including rivers, lakes, ponds, and dug-outs;
- Groundwater, including both non-saline and saline groundwater; and
- Other sources such as produced water and treated wastewater.

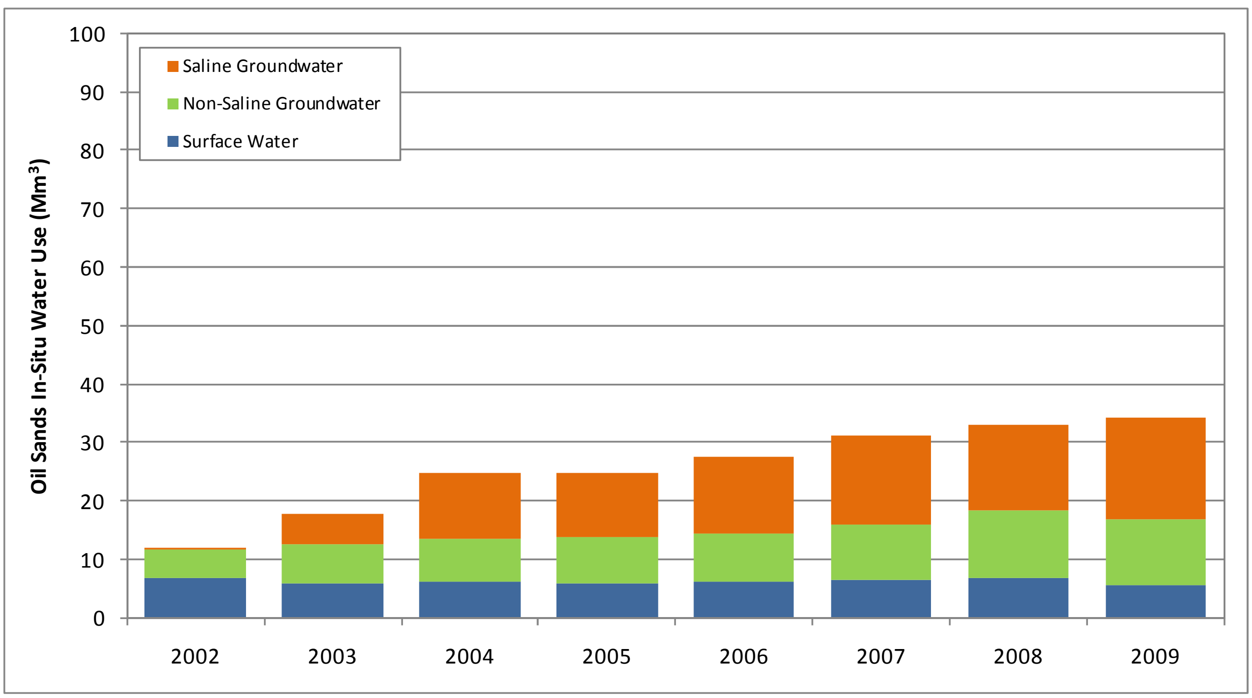
Specific water sources for the sector are summarized below.

- Oil sands mining water use relies on the Athabasca River basin, and primarily on direct withdrawal from the Athabasca River as shown in Figure 2-6. Mining operations are also licenced to account for natural flows that would normally discharge from mine areas and for groundwater discharge to the mine pits. The Athabasca River withdrawal occurs year-round, while the other water uses occur primarily in the summer.
- Oil sands in situ operations use various water sources, as shown in Figure 2-7, including surface water, non-saline groundwater, and saline groundwater.
- Oil production by conventional and EOR methods uses a variety of sources, as shown in Figure 2-8.
- Gas plant water sources typically include non-saline and saline groundwater. Gas plant use was 5.8 Mm^3 per year on average from 2005 to 2008 (Alberta Environment, 2010).
- Well drilling and completions use a variety of water sources, such as dugouts or sloughs and, on a temporary basis, rivers or lakes. In total, water used for drilling and completions was estimated to be about 8.3 Mm^3 per year on average from 2000 to 2009, based on the number wells drilled per year and assuming 500 m^3 per well.



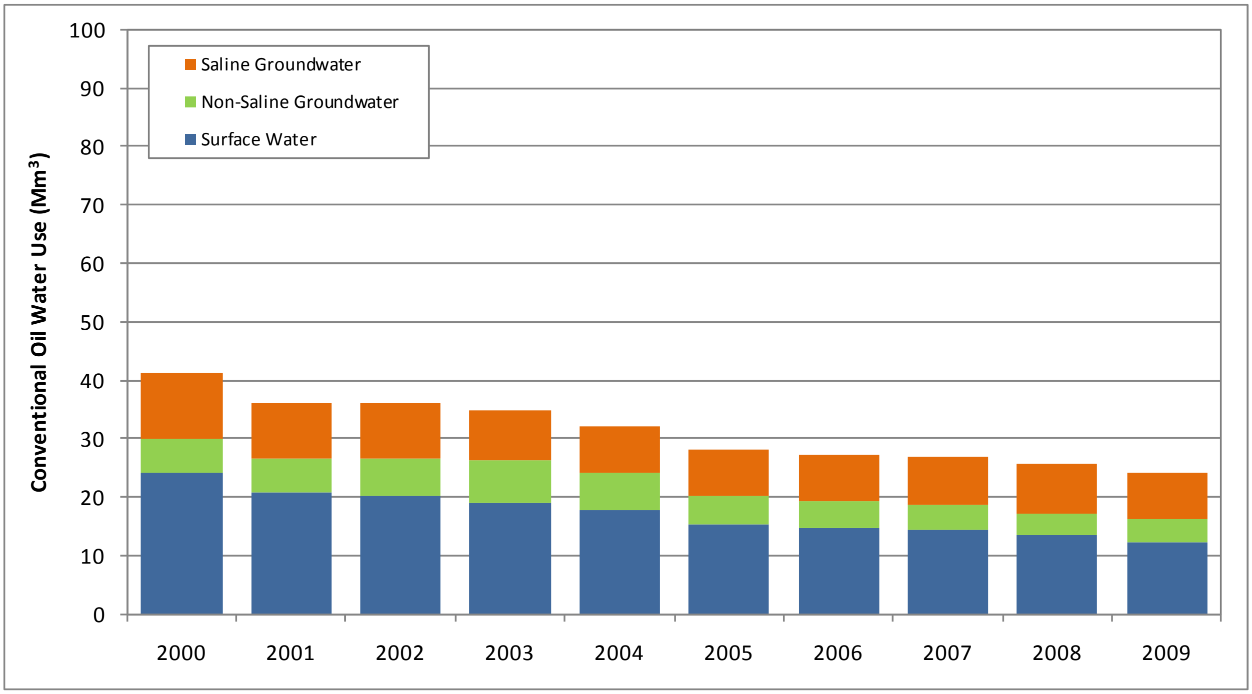
Source: Alberta Environment

Figure 2-6: Oil Sands Mining Water Use (2000 to 2009)



Source: Alberta Environment

Figure 2-7: Oil Sands In Situ Water Use (2000 to 2009)



Source: Alberta Environment

Figure 2-8: Conventional Oil and EOR Water Use (2000 to 2009)

2.1.3 Description of Key Water Use/Users

Water use processes

Water is a critical component of oil and gas production in Canada. It is used for various operations in oil and gas exploration and extraction activities, including:

- Hot water treatment process in oil sands mining operations (to extract oil from sand and silt and clay);
- Steam generation for in situ oil sands operations (to liquefy the bitumen);
- On-site upgrading of bitumen in oil sands operations (to decrease viscosity for transportation and refining);
- Drilling and completion of both oil and gas wells;
- Hydraulic fracturing (oil and tight gas formations);
- EOR, such as the injection of water to increase pressure in oil-producing formations; and
- Gas plant processes such as cooling towers.

Information on water requirements and uses for different project types is presented in Table 2-3.

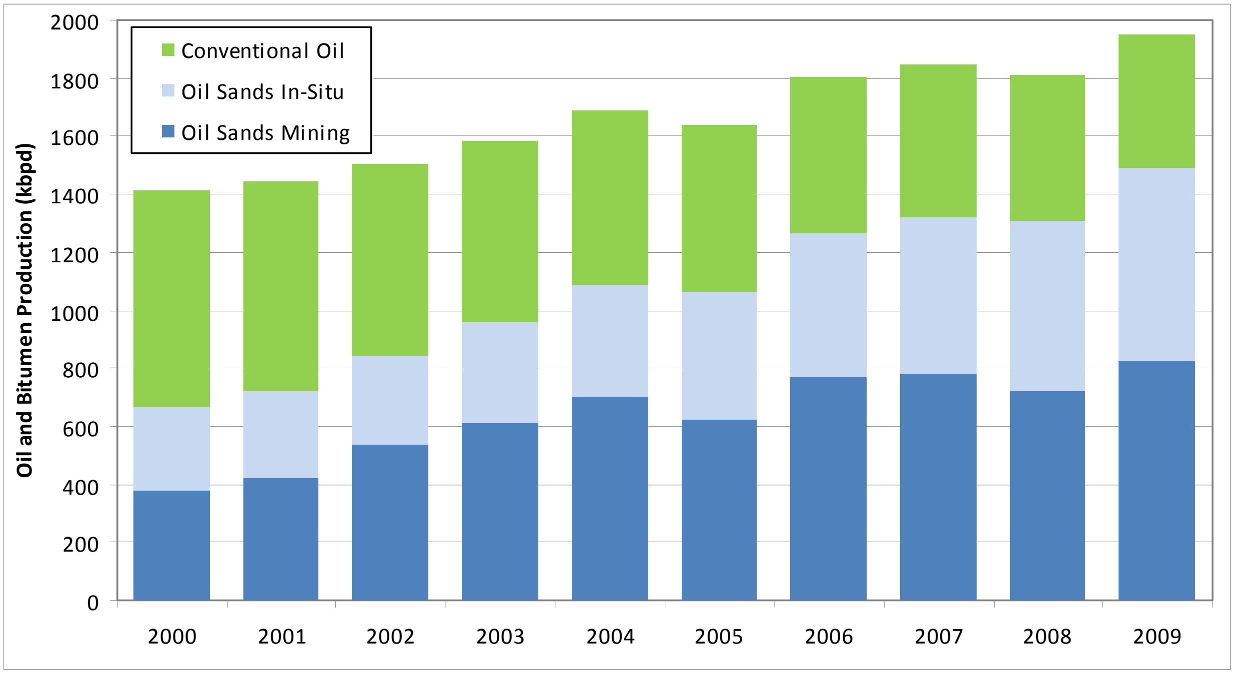
Table 2-3: Water Uses and Sources by Operation Type

Operation type	Typical geographic area	Water uses	Typical water source(s)
Conventional Oil and Gas			
Shallow gas (including coalbed methane)	Central and Southern	Drilling and completions	Surface water
Deep gas	Western	Drilling and completions	Surface water, saline groundwater
Shale gas (after 2015)	Northwestern	Drilling and completions	Surface water, saline groundwater
Conventional oil (primary recovery)	Various	Drilling and completions, minor pressure maintenance	Surface water, saline groundwater, non-saline groundwater, produced water
Enhanced oil recovery (secondary recovery)	Various	Drilling and completions, waterfloods	Surface water, saline groundwater, non-saline groundwater, produced water
Oil Sands			
Mining	Northern	Extraction, upgrading	Surface water, process-affected water, non-saline groundwater
In situ	Northern	Drilling, steam generation	Saline groundwater, non-saline groundwater, surface water, recycled process water

Goods and services provided

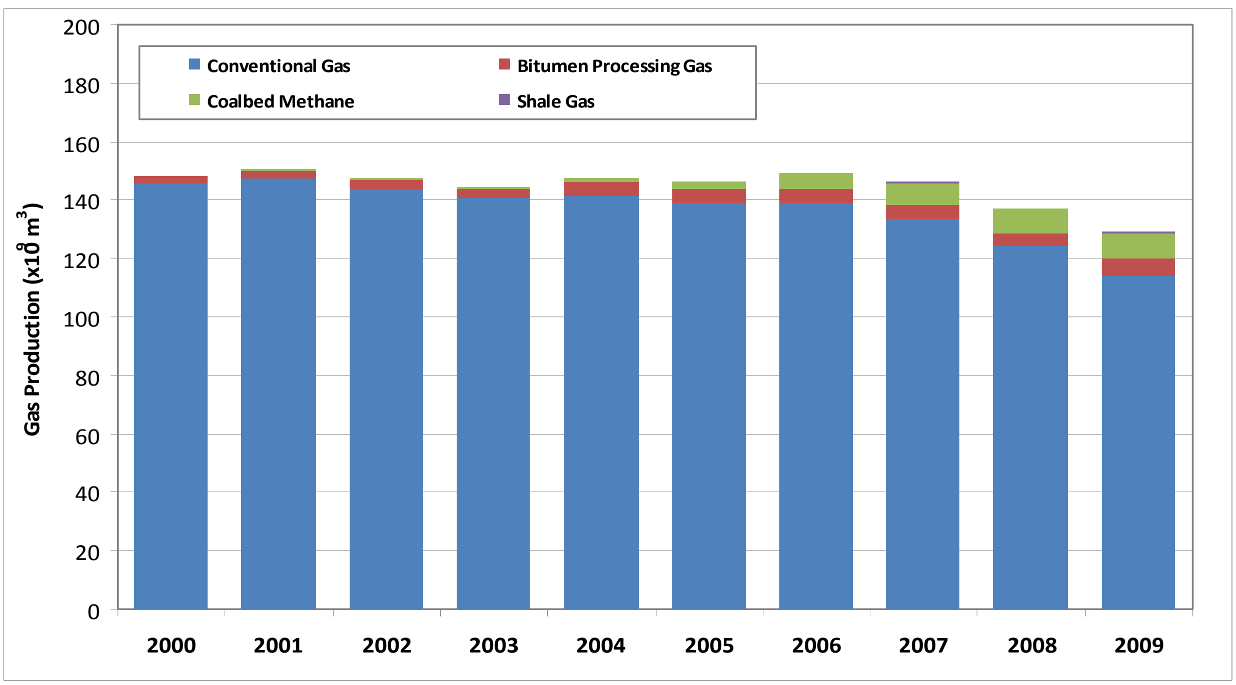
Alberta's oil and gas sector provides energy to the Canadian and international public, businesses and government organizations for heating, transportation, electricity generation, energy for manufacturing, and other direct uses. Hydrocarbons are also used extensively to manufacture feedstock for fertilizers, petrochemicals (including plastics, synthetic materials, and asphalt) and many other products that are integral to the functioning of today's society.

The use of water allows industry to produce more oil; in effect, increasing Alberta's resource base and associated benefits. About 75% of Alberta's oil production (conventional, in situ and mining) is water-assisted (CAPP, 2010). All together, the various water sources and uses of water allow industry to produce more than 100 Mm^3 of oil and bitumen per year, and about 130 trillion m^3 per year of marketable gas. Oil and bitumen production is shown in Figure 2-9. Marketable gas production is shown in Figure 2-10.



Note: [1] kbpd = thousands of barrels per day of production. 1 kbpd = 158. 987 m^3
Source: Alberta Environment (2005 to 2008) and ERCB (2000 to 2004)

Figure 2-9: Oil and Bitumen Production (2000 to 2009)



Source: Petroleum Registry of Alberta

Figure 2-10: Marketable Gas Production (2000 to 2009)

The upstream oil and gas sector's water use provides value to Albertans in the form of royalties and social benefits such as employment. For example:

- Natural gas production is Alberta's largest source of resource development revenue, accounting for more than $25.4-billion in royalties paid to the Government of Alberta from fiscal 2005/2006 through fiscal 2008/2009. This represents about 62% of all provincial revenue from non-renewable resources over that period (Alberta Energy, 2010).
- During the 2008/09 fiscal year, natural gas production accounted for $5.8-billion in royalty payments to the provincial government. Oil sands production and conventional crude oil production accounted for $3-billion and $1.8-billion, respectively (Alberta Energy, 2010).

2.2 Linkages with Other Water Systems and Operating Parameters

Concurrent water uses

Almost no water used by the upstream oil and gas sector is used concurrently by other industry sectors. Infrastructure is normally dedicated to industry needs, and return flow to the environment is small for most uses.

Some concurrent use does occur within the sector, as water is recycled for EOR, steam generation for in situ thermal operations, use of reclaimed water from oil sands mine tailings, and other uses.

Normal operating parameters

Water licence conditions and water-related infrastructure for the sector normally operate based on site-specific conditions in areas of the province that are not considered water-short. For example, the mining sector must meet seasonal restrictions for water withdrawal from the Athabasca River, based on the (Lower) *Athabasca River Water Management Framework* (Alberta Environment and Department of Fisheries and Oceans, 2007). Another example is the *Cold Lake-Beaver River Water Management Plan* (Alberta Environment, 2006c). Future industry withdrawals may also follow restrictions based on the *Water Management Framework for the Industrial Heartland and Capital Region* (Alberta Environment, 2009).

2.3 Review of Current Policies, Programs, Plans and Legislation

2.3.1 Related Policies, Programs and Plans

In addition to the *Water for Life* strategy (see Section 1.1), there are a number of policies, programs and plans that relate to water management in Alberta. The industry considers all of these initiatives worthwhile and participates with enthusiasm, but a frequent challenge is dealing with the unintended consequences of one policy affecting the industry's ability to meet another policy. The balancing of priorities is an important but difficult objective to achieve.

Wetland Policy

It is anticipated that the Alberta Wetland Policy will be released in 2012. The policy goal is to conserve, protect, restore and manage Alberta's wetlands. Alberta Environment is currently assembling an engagement strategy that will help ensure stakeholder contribution to the development of policy details. The oil sands region exists in an area of expansive wetlands; therefore, this is a very important policy for the upstream oil and gas sector.

Land-use Framework

The *Land-use Framework* (LUF) (Alberta Environment, 2008a) is a comprehensive approach to planning to better manage public and private lands and natural resources to achieve Alberta's long-term economic, environmental and social goals. Under LUF, regional land-use plans will be developed for each of the seven new land-use regions: Lower Athabasca; South Saskatchewan; North Saskatchewan; Upper Athabasca; Red Deer; Upper Peace; and Lower Peace.

Water management frameworks

Alberta Environment is developing environmental management frameworks to contribute to cumulative effects management and LUF implementation. Groundwater Management Frameworks have been drafted for three areas of the Lower Athabasca land-use region: North Athabasca Oil Sands; South Athabasca Oil Sands; and Cold Lake-Beaver River. A Lower Athabasca River Surface Water Quality Management Framework has also been drafted.

Several other water management frameworks exist for specific regions of the province. All management frameworks are intended to be updated periodically to account for new information and priorities.

Water Conservation and Allocation Policy for Oilfield Injection

The *Water Conservation and Allocation Policy for Oilfield Injection* (Alberta Environment, 2006d) aims to reduce or eliminate allocation of non-saline water for oilfield injection. This policy will be reviewed and updated by Alberta Environment over 2011-2012.

The current policy requires an environmental net effects evaluation of applications for both licences and renewals. Section 3.2.6 of this policy states: "In some cases, the use of an alternative technology or alternative water source may result in more environmental impacts than the use of non-saline water. By switching to saline water use for the intended project, it is expected there will be additional energy requirements for obtaining the saline water, resulting in higher project emissions. In addition, there will likely be increased land disturbance for saline pipelines, additional waste products and associated environmental footprint to safely dispose of these products." This particular section of the policy is important because most new water used for oil sands in situ development is projected to come from saline sources. However, the decision to use saline over non-saline sources must consider the environmental net benefit and balance other environmental and economic tradeoffs.

2.3.2 Related Legislated Conditions or Clauses

All aspects of the oil and gas industry in Alberta have been strictly regulated for many years by several provincial departments and agencies including Alberta Environment, the ERCB and Alberta Sustainable Resource Development (SRD), and by municipal plans and bylaws. Federal agencies also influence regulation of Alberta's oil and gas sector, including Environment Canada, the Canadian Environmental Assessment Agency, Canadian Council of Ministers of the Environment, the Department of Fisheries and Oceans, and Transport Canada.

Significant water regulations for the Alberta oil and gas industry are summarized in Appendix A. They include the Alberta *Water Act*, the Alberta *Environmental Protection and Enhancement*

Act, the *Oil and Gas Conservation Act*, various ERCB Directives, the *Public Lands Act*, the *Canadian Environmental Protection Act*, *Canadian Environmental Assessment Act*, the *Fisheries Act*, the *Navigable Waters Protection Act*, and others.

2.4 Sector History of CEP

The upstream oil and gas sector has been actively pursuing CEP opportunities on a number of fronts for several years. In addition to environmental benefits, water CEP tends to reduce net costs to industry due to the direct relationship between water and energy use. Large amounts of energy are used to process and move water through oil and gas operations. Water is often seen as a low-cost resource for the oil and gas sector; however, as the regulation and costs of water-related infrastructure, treatment and transportation have increased, the sector has become more aware of the costs associated with using water. Consequently, the sector normally tries to use water only as required and as determined by the available economic alternatives. As a result of these efforts, the sector has already realized significant, measurable water productivity improvements. Although the most obvious CEP opportunities with the largest gains have already been implemented, the recent trend toward improved non-saline water use productivity is expected to continue through 2015.

One challenge for the sector is that the viability of CEP opportunities depends on the details of each project, including reservoir/process compatibility, transportation costs and associated impacts, energy inputs required for treatment, and disposal of residual water. In other words, different environmental aspects, such as the energy required for water treatment, may have a more significant overriding impact than the quantity of water used. A life cycle analysis can help to assess all the benefits and costs.

Highlights of the sector’s contributions to water CEP are discussed below.

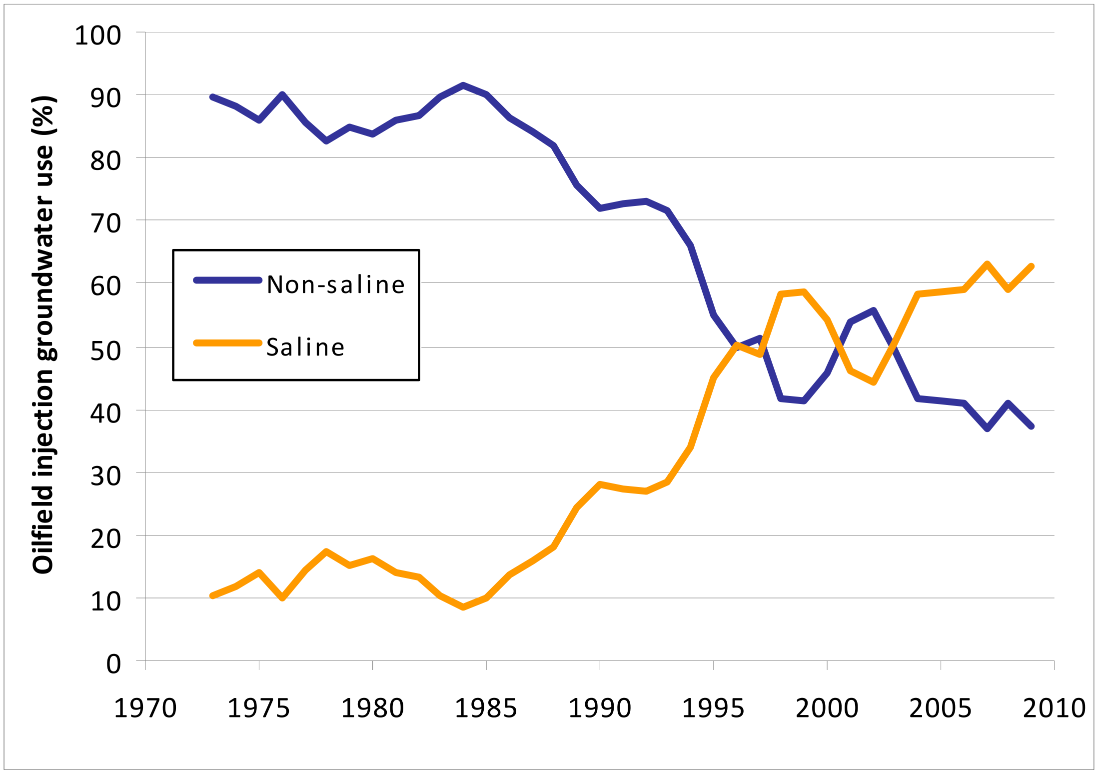
2.4.1 Technological Innovation

The design phase of every project includes a research and development (R&D) component for identifying opportunities to reduce non-saline water use. Many operators have initiated water conservation audits and other measures to improve water use efficiency. As a result, non-saline water use has been reduced on a unit production basis using new or alternative techniques and water sources, such as those noted below:

- Use of saline water instead of non-saline water;
- Maximizing recycling of produced water;
- Maximizing the use of produced water for pressure maintenance and waterfloods where possible; and
- Exploration of alternative techniques that minimize or avoid water use, or improve the efficiency and productivity of water use; e.g., mixable floods (CO_2), polymer floods, and fire floods.

In water-short areas in southern Alberta, the relatively mature upstream oil and gas developments now tend to restrict non-saline water use to drilling and completions activities, and overall use of non-saline water for EOR is decreasing throughout the province.

The sector is also actively pursuing water conservation in areas that are not water-short. One of the key water conservation trends is the use of saline groundwater to avoid the use of more valuable non-saline water (see Figure 2-11).



Source: ERCB

Figure 2-11: Saline versus Non-saline Groundwater Use for EOR and Thermal In Situ Production (1972 to 2009)

Some specific examples of CEP improvements made by companies are provided below:

- Devon Energy designed a steam-assisted gravity drainage (SAGD) facility that would use zero non-saline water in its steam generation process. The resulting Jackfish project, Devon's 35,000 barrel per day thermal heavy oil facility near Conklin in northeastern Alberta, became the first commercial SAGD operation to rely solely on saline water for production. Devon is pursuing similar principles in its Jackfish 2 Project, expected to be on-stream in 2011.
- Cenovus Energy is recycling blowdown water from cooling equipment back into its produced water stream and employing reboiler technology to recapture brackish water in its process, ultimately turning 90% of the water it uses into steam at its SAGD project at Christina Lake in northeastern Alberta.
- CNRL has developed a technique of injecting waste carbon dioxide (CO_2) into the tailings slurry at Horizon, its oil sands mining project located north of Fort McMurray, causing fine silt and clay particles to settle to the bottom of the tailings pond more quickly. This makes more water available at the top of the pond for recycling and reuse in

the bitumen extraction process. Not only will this reduce the footprint of the tailings pond and decrease the amount of water withdrawn from the Athabasca River needed to process bitumen, but it will also significantly reduce the facility's CO_2 emissions.

- Suncor Energy is close to being able to bring on a zero-liquid discharge and recycling system at its in situ facility at MacKay River north of Fort McMurray. An extensive research and development program undertaken by Petro-Canada (acquired by Suncor in 2009) led to a system of treating and recycling produced water from its SAGD process and turning it into injection steam. 90% of the facility's injection steam is recycled continuously in this manner, requiring no surface water and very little groundwater.
- CNRL constructed the first fisheries compensation lake in the oil sands region to compensate for lost fish habitat when its Horizon project was built north of Fort McMurray. Wapan Sakahikan (Cree for Horizon Lake) is 76.7 square hectares and will be home to native species of fish identified as traditionally important food resources for First Nations. To aid in the success of a self-sustaining fish population (not stocked), habitat enhancements have also been made. These include shoreline diversity, islands and a variety of vegetation.
- Syncrude Canada has taken concerted efforts to increase their water efficiency. Over the last decade, Syncrude has reduced water intake by an average of 7 million m^3 annually by: converting systems to use recycled water instead of non-saline water; increasing maintenance to ensure water equipment operates at peak efficiency; and improving operation of their cooling towers. Additional projects are being explored that could further reduce water withdrawals.
- Penn West Energy is exploring saline groundwater sources as an alternative to drawing surface water from the Pembina River for EOR operations at its Cherhill facility, located northwest of Edmonton. To date, the company has tapped saline sources able to supply one-fifth of the 1,000 m^3 per day target water requirement for its operations.
- Imperial Oil's Cold Lake operation in northeastern Alberta is the largest thermal in situ heavy oil operation in the world. By developing specialized techniques for recycling the water produced with the bitumen, the operation currently recycles about 95% of this produced water. As a result, the volume of non-saline water used has declined despite expansion of the operation. This improvement is even more apparent when looking at non-saline water use efficiency, which has been reduced from approximately 4 units of non-saline water per unit of bitumen production in the mid-1970s to approximately 0.5 units today.
- Devon Energy was the first company in Alberta to utilize a new gelled frac fluid that uses produced water. Typically, non-saline water is used when creating downhole fractures. The test used produced water from Devon's Dunvegan gas plant in northwestern Alberta, saving up to 2,000 m^3 of non-saline water per well. Using water from the Dunvegan plant lessened the distance between the water source and the frac job. This resulted in lower costs, reduced vehicle emissions and less traffic in the Town of Fairview. Devon plans to use this process whenever feasible.

2.4.2 Performance Metrics

CAPP Responsible Canadian Energy™ (RCE) program

CAPP launched the RCE Program in 2010. Building on the success of CAPP's long-standing Stewardship Program, RCE reflects the oil and gas industry's ongoing commitment to responsible development and continuous improvement in environment, health and safety, and social performance. Participation in the RCE program is mandatory for CAPP members.

Based on the RCE Vision and Principles (www.capp.ca/rce/vision**)**, Guidelines for Management System Implementation (Guidelines) have been designed as tools to support performance improvement for key stewardship issues, including water management.

The Guideline for Water Management identifies three key issues for which effective management will support performance improvement:

- Water footprint;
- Water optimization; and
- Watershed-based management.

Prior to the launch of the RCE program, CAPP members voluntarily submitted data on water use each year under the CAPP Stewardship Program. Water use reporting became mandatory in 2008. The metrics are currently being reviewed for alignment with the RCE Program.

Corporate sustainability reports

Many companies formally report on their environmental performance in annual corporate sustainability reports, including additional metrics for water use. The most commonly reported metric is total annual water use, but others include efficiency (water used per volume of oil or barrel of oil-equivalent produced), reuse rates, volume of water withdrawn and returned, and annual water use broken down by sector or source.

The Global Reporting Initiative (GRI) Standards are often used or referenced to document water use in corporate sustainability reports. The GRI indicators for water include:

- Total water withdrawal by source;
- Water sources significantly affected by withdrawal of water; and
- Percentage and total volume of water recycled and reused.

2.4.3 Reduction of Licenced Allocations

Return of allocations to the Province

Some water licences issued under the previous *Water Resources Act* had a deemed expiry date. These licences were regulated under the terms and conditions in place when they were issued, even after the new *Water Act* took effect in 1999. In 2006, Alberta Environment began a process to assess all of industry's deemed water licences. All licences were assigned an expiry date of December 31, 2008 and industry was required to assess all deemed licences by following the *Water Conservation and Allocation Guideline for Oilfield Injection* (Alberta Environment, 2006d) to identify opportunities to reduce water allocations and actual use. In total, approximately 160 water licences were reviewed by member companies through this process. The review was completed in 2008, resulting in a 50% reduction in the volume of water allocated in deemed licences held by the oil and gas industry, as shown in Table 2-4.

Table 2-4: Water Returned to Province Following Review of Deemed Licences

Licences	Region	No. of Licences	Original Allocation	New Allocation
Expired	All	89	8,630,446	--[1]
Issued	Northern	24	5,845,836	7,601,892[2]
	Central	44	3,871,728	1,333,391
	Southern	0	0	0
Pending	2008	0	0	0
	2009	1	194,545	194,545
Total Volume (m^3/year)			18,542,555	9,129,828

Notes: 1. Expired licences were subsequently cancelled.
2. The large increase in allocations in the Northern Region was the result of allocations for new projects.
Source: Alberta Environment

In early 2009, industry also undertook a voluntary review of permanent licences issued under the *Water Resources Act* for oilfield injection of non-saline water, in the spirit of the oilfield injection policy. This review resulted in the return of 7.95 Mm^3 of unused allocations to the Province.

Donation of allocations to protect instream flow

ConocoPhillips has held a licence to draw water from the Medicine River in central Alberta since 1968, and recently applied to donate over 50% of the licenced volume (123,000 m^3 per year) to the Water Conservation Trust of Canada. If accepted after an environmental review, a public notice period and provincial government review, this will be the first licence transfer to privately protect instream flow in Alberta.

2.4.4 Partnerships and Research

A collaborative approach to water management is critical for setting regional priorities and sharing information to achieve those goals. CAPP participates in a number of joint initiatives, including those listed below.

Alberta Innovates - Alberta Water Research Institute (AWRI)

AWRI coordinates world class and leading edge research to support *Water for Life* goals and objectives. An example of work related to the industry is the AWRI partnership with General Electric Water and Process Technologies to improve treatment and reuse of industrial produced water in oil sands operations.

Alberta Oil Sands Technology and Research Authority (AOSTRA)

AOSTRA targets new production techniques for oil sands development, including methods that are less water-intensive.

Alberta Upstream Petroleum Research Fund (AUPRF)

AUPRF is part of the upstream oil and gas sectors' Broad Industry Initiatives (BII) fund, which is generated through an Alberta well levy. Water management and water quality protection are two of the main strategic areas for which research funds are allocated. Water research projects are generally presented to industry at an annual water forum on research and best management practices, sponsored by the Petroleum Technology Alliance of Canada (PTAC).

Alberta Water Council

The Alberta Water Council is a multi-stakeholder partnership to monitor and steward implementation of the *Water for Life* strategy and to champion achievement of the strategy's outcomes. The upstream oil and gas sector participates on the Alberta Water Council Board and on many of its Project Teams related to various aspects of *Water for Life*.

Canadian Oil Sands Network for Research and Development (CONRAD)

CONRAD is a network that facilitates research in science and technology for the oil sands. Researchers meet once every two years to share results and innovations. Water conservation measures, such as increased water recycling efficiencies is a key topic.

Cumulative Environmental Management Association (CEMA)

CEMA is a multi-stakeholder group that studies the cumulative environmental effects of industrial development in the Wood Buffalo region of northeastern Alberta.

National Round Table on the Environment and the Economy (NRTEE)

NRTEE's Water Program is exploring the sustainable use of water by the natural resource sectors in Canada, with specific research on the areas of water allocation, policy and governance.

Oil Sands Leadership Initiative (OSLI)

OSLI is an industry collaboration focused on demonstrating and communicating environmental, social and economic performance and technological advancements in Alberta's oil sands. The OSLI Water Management Working Group is currently looking at regional solutions to saline water sourcing and a long-term strategy for tailings water disposition.

Oil Sands Tailings Research Facility (OSTRF)

OSTRF supports research on a variety of topics related to oil sands tailings. This facility has the potential to produce large-scale water savings through the development of tailings technologies with higher solids content. Such tailings have less water stored in their pore spaces, which makes more water available for recycling.

Regional Aquatics Monitoring Program (RAMP)

RAMP is an industry-funded, multi-stakeholder environmental monitoring program in the oil sands region of northeastern Alberta. Many oil sands companies participate in RAMP, which has been collecting data annually from the Athabasca River and its tributaries, the Athabasca River delta, and regionally important lakes and wetlands since 1997. RAMP regularly undergoes external scientific peer reviews to evaluate and recommend improvements to the program.

Watershed Planning and Advisory Councils (WPACs)

WPACs engage governments, industry, non-government organizations and the public in watershed assessment, planning and improvement. Involvement in such initiatives provides a realistic understanding of regional water availability and associated constraints. Ten WPACs have been established in Alberta, and one more is being formed for the Peace River watershed. The upstream oil and gas industry currently has representation on every WPAC.

Other partnerships

Many individual operators contribute funds to not-for-profit groups that are working to support a sustainable aquatic environment (e.g., Ducks Unlimited, Alberta Ecotrust). CAPP members also support various educational institutes, educational scholarships, and other similar initiatives.

3 Water Supply and Demand Considerations

3.1 Water Demand Forecasting

Demand forecasting methodology

The water demand forecast covers the period to 2015, in accordance with the Alberta Water Council's recommendations. The methodology to forecast water demand is based on the current CAPP production forecast and projected water use rates (i.e., water diversion per unit of production). Parameters for the forecast are described below.

- All forecasts are based on the current CAPP production forecast (CAPP, June 2010) for raw bitumen, and for light, medium, and heavy oil production.
- All forecasts are based on industry average water use rates that will vary among the operations or regions. For example, some conventional oil production may use 2.0 or more units of water for each unit of oil produced (or 2.0 water:oil by volume), while some conventional oil production does not use significant volumes of water.
- Forecasts differentiate between use of saline water and non-saline groundwater or surface water sources.
- For oil sands mining forecasts:
  - In terms of non-saline water use productivity, Athabasca River withdrawal is expected to be 2.3 water:bitumen volume ratio for average climate conditions and 2.7 in years where there is a projected mine startup. Note that the productivity for individual mines during startup is lower, but the cumulative average is anticipated to be 2.7. During non-startup years, the forecast water use is based on the 2005 to 2007 reported average non-saline water use productivity. Actual water use may be higher or lower due to climate conditions, according to an OSDG study of potential future water use by oil sands mines which forecast higher water use during dry conditions (Golder Associates, 2009). Water use may also be higher during the startup of new mines, due to initial filling of ponds and the commissioning process for recycle water systems.
  - The surface runoff diversion forecast for mine sites was based on projected closed-circuit areas and available basin water yield information. Volume estimates assume an average surface runoff of 56 millimetres per year, based on typical lowland natural areas in the oil sands region (Golder Associates, 2003). For the purpose of estimating the surface runoff volume, mine site closed-circuit areas were based on available information provided in environmental impact assessments as of 2005, plus partial updates for several mines due to delayed startup.
  - Collection of groundwater discharge to mine pits assumes that the future volume will be about 9.4 Mm^3 per year, the average reported discharge in 2008 and 2009.
- For oil sands in situ forecasts:
  - Includes both primary and thermal production, plus a very small amount of experimental production.
  - The primary production forecast assumes the 2009 production rate of 207,000 barrels per day.

- The oil sands in situ primary production water use forecast is 9.2 Mm^3 per year, including 80% non-saline water use, based on the reported average water use for waterflood production at CNRL Brintnell and Encana Pelican Lake from 2005 to 2008. Oil sands in situ production at the Shell Peace River pilot plant was assumed to continue using 2.5 Mm^3 per year, similar to 2008.
- Oil sands in situ total makeup water used for thermal operations was forecast to be 1:1 water:bitumen, based on the reported average non-saline water use productivity from 2002 to 2008. Oil sands in situ thermal use of saline water sources was forecast based on commitments reported as part of the environmental permitting process for various operations.
- Oil sands in situ water use does not include Suncor's Firebag operation, which was reported as part of Suncor's oil sands integrated operations with mining. The Firebag facility is licenced to use makeup water that is recycled from Suncor's oil sands mining operation via pipeline.

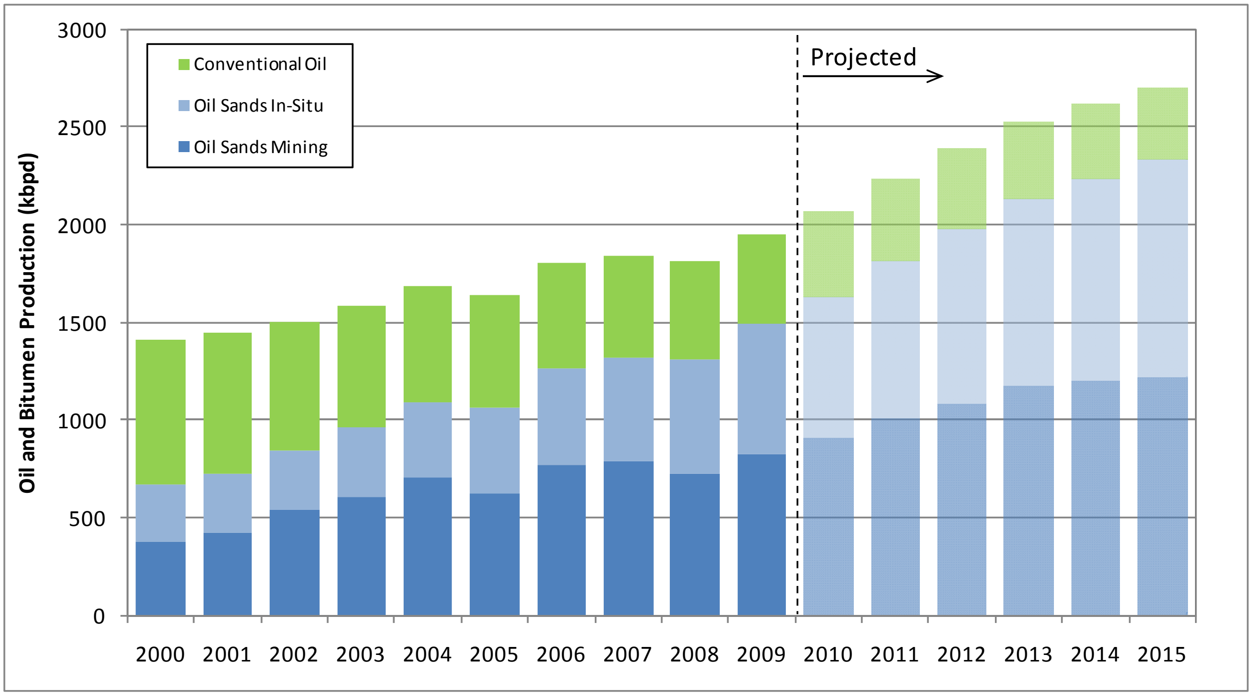
- For conventional oil forecasts:
  - The conventional oil production forecast includes EOR, which has historically accounted for about 50% of total conventional oil production (based on ERCB data from 2000 to 2007, and on Petroleum Registry information in 2008). However, EOR production typically accounts for most of the water used in conventional oil production.
  - Forecast water use for conventional oil is expected to be 0.87 water:oil, based on the reported average non-saline water use productivity from 2005 to 2008 for all oil production, including EOR production methods. This forecast was assumed to include any recent trends toward the use of alternative technologies that might reduce the overall water requirement.
  - Conventional oil forecast water use for non-saline sources is 0.6 water:oil, based on the reported average non-saline water use productivity from 2005 to 2008. This forecast was assumed to represent current industry trends and water CEP activity.
- The gas plant (non-saline) water use forecast of 5 Mm^3 per year is based on the typical reported water use from 2005 to 2008.
- The well drilling and completion water use forecast assumes 500 m^3 per well, and 16,600 wells per year based on the average number of wells per year from 2000 to 2008.

Forecasts are not available for specific river basins.

Demand forecast results

Annual oil and bitumen production in Alberta was about 110 Mm^3 in 2009. This is expected to increase to 160 Mm^3 per year by 2015. The increased production will be due primarily to oil sands in situ and mining production, while conventional oil production will decline. The forecast production increase is illustrated in Figure 3-1.

The corresponding demand for non-saline water is projected to approach 250 Mm^3 by 2015. About two-thirds of the water use is expected to be withdrawn from the Athabasca River for oil sands mining. Historical non-saline water use data and forecast non-saline water demand are shown in Figure 3-2 and discussed in the following sections.



Source: ERCB (2000 to 2004); CAPP (2005 to 2015)

Figure 3-1: Sector Oil and Bitumen Production Forecast (to 2015)

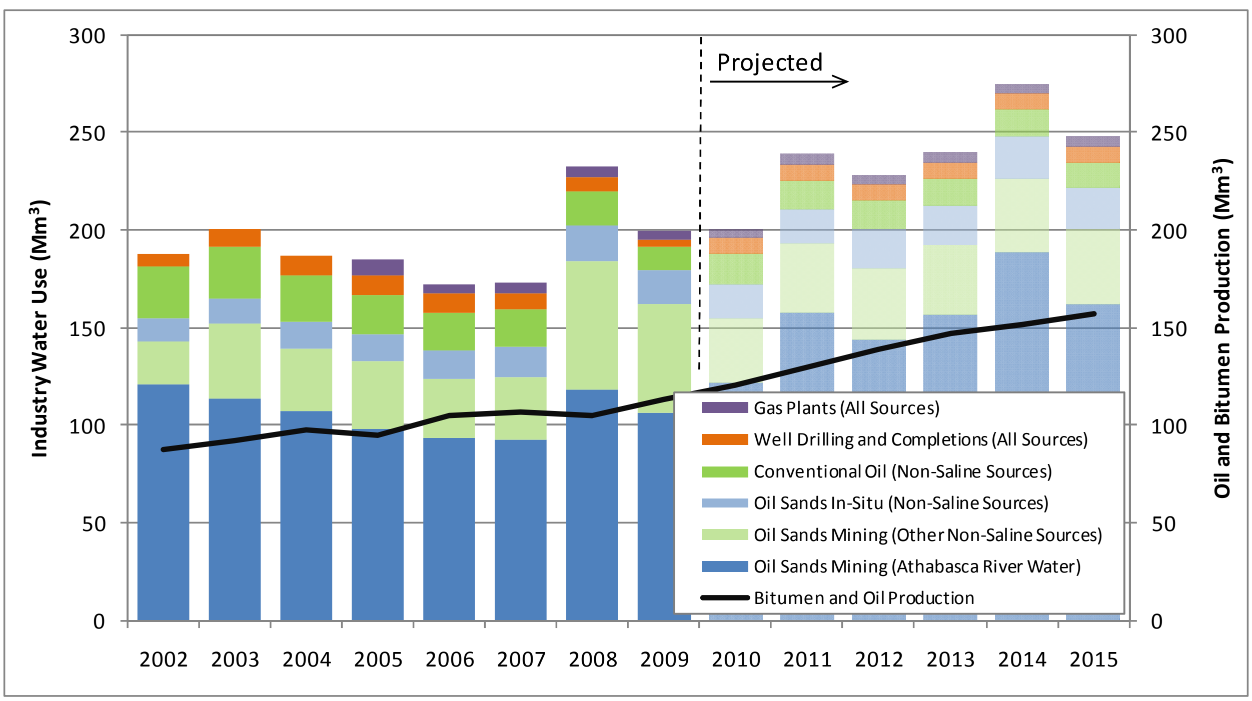


Figure 3-2: Non-saline Water Use Forecast (to 2015)

As discussed in Section 2.4, the sector's CEP efforts to date have already achieved quantifiable results in improving water productivity compared to the baseline years of 2002 to 2004. The water demand forecasts assume that the sector will continue this progress through 2015.

Oil sands mining water use forecast

The oil sands mining water use forecast consists of three portions:

- Athabasca River withdrawal;
- Surface water collection from the mine site; and
- Collection of groundwater discharge to the mine pit.

The amount of Athabasca River water to be withdrawn by oil sands mines is expected to increase as approved mines are developed, reaching about 162 Mm^3 or 5.1 m^3/s by 2015. The projected water use for oil sands mining is shown in Figure 3-3 for average climate conditions. Actual water use may be higher or lower due to climate conditions, according to an OSDG study of potential future water use by oil sands mines which forecasts higher water use during dry conditions (Golder Associates, 2009).

Non-saline water use productivity is expected to be higher in 2011 and 2014 due to startup of the Shell Jackpine, Imperial Kearl, and Syncrude Aurora South mines. The additional water use is expected to be about 20 Mm^3 during those particular years, depending on the size and configuration of the external tailings area at each mine. This additional startup water is primarily due to filling of a water cap in the initial tailings storage area, which is necessary to recycle water from the tailings pond at the start of bitumen production.

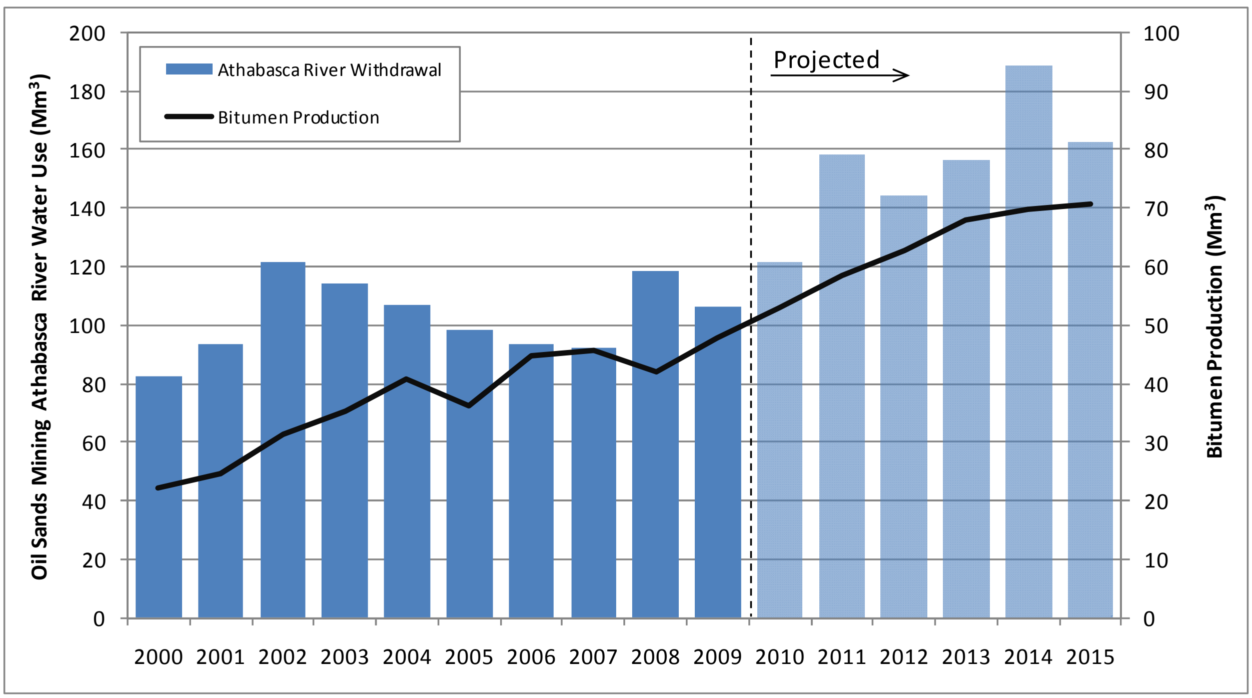


Figure 3-3: Oil Sands Mining Athabasca River Water Withdrawal Forecast (to 2015)

Other water sources by the oil sands mining sector include seasonal surface runoff from the mine site and groundwater discharge to the mine pit. The amount of surface runoff is expected to be about 38 Mm^3 per year by 2015, based on average climate conditions. The amount of groundwater discharge in 2015 is assumed to be about 9.4 Mm^3.

Seasonal surface runoff is licenced to account for the natural flows that would otherwise discharge to the Athabasca River, but are captured as part of closed-circuit mining operations. This portion of the basin water yield occurs primarily during snowmelt and in the summer months. This water is collected and recycled within the mine site. The collected volume also varies depending on seasonal precipitation.

The forecast Athabasca River water use assumes current water management practices and tailings technologies, and depends on the development schedule of proposed or potential mines. The projection does not include potential changes in tailings technology.

Oil sands in situ water use forecast

The oil sands in situ water use forecast includes water used for a variety of production methods, including thermal oil sands bitumen production, cold flow bitumen production or Cold Heavy Flow Oil Production with Sand (CHOPS), plus various primary and EOR production methods such as waterfloods. The forecast water use for in situ production is shown in Figure 3-4.

Oil sands in situ water use is expected to increase in proportion to production. However, most new water used is expected to come from saline sources. The use of surface water and non-saline groundwater is expected to increase from 16.7 Mm^3 in 2009 to about 22 Mm^3 by 2015. Saline water use is projected to be about 45 Mm^3 by 2015, provided that volumes and quality are sufficient to meet the demand in the location of future development. The decision to use saline over non-saline sources must also consider the environmental net benefit and balance other environmental and economic tradeoffs.

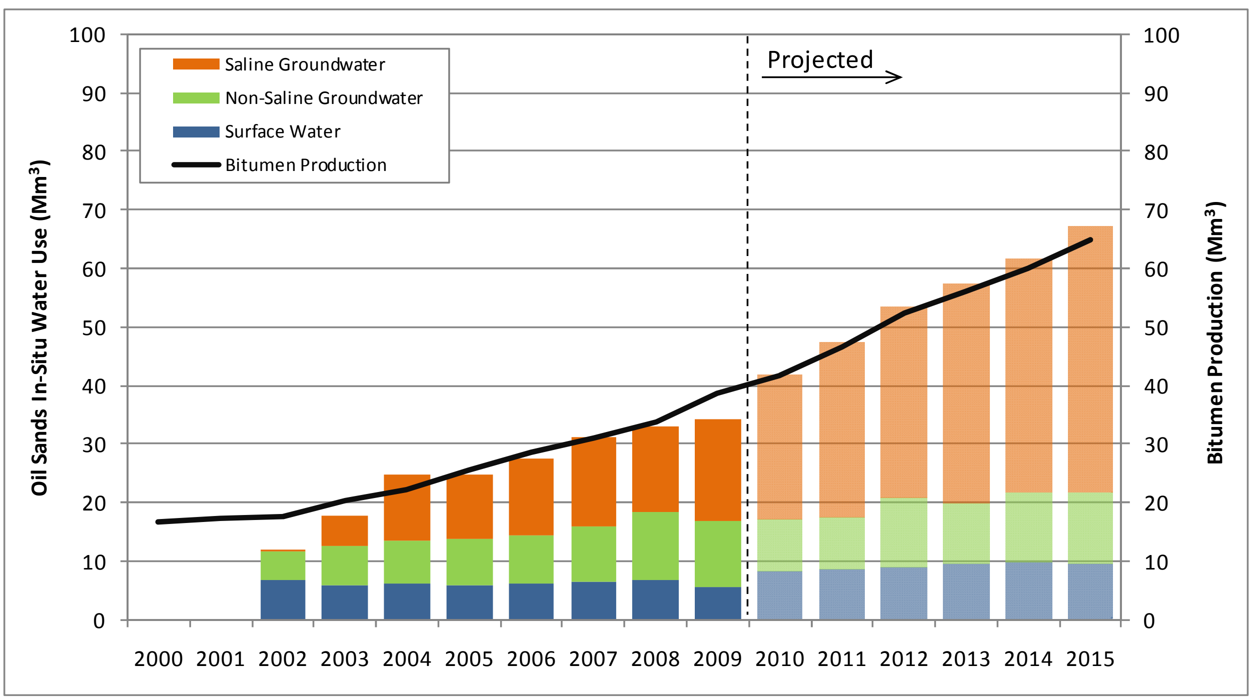


Figure 3-4: Oil Sands In Situ Water Use Forecast (to 2015)

Conventional oil water use forecast

The water use forecast for conventional oil includes water used for EOR methods, which is the predominant use of water for oil production.

Based on the most recent CAPP production forecast, conventional oil production in Alberta is projected to continue the current declining trend, resulting in a similar decline in water use. The projected non-saline water use of 13 Mm^3 by 2015 is based on the continuation of current trends, which are illustrated in Figure 3-5.

Both non-saline and saline water used for EOR could potentially increase in the future due to renewed interest in developing mature conventional oil fields, made possible by advances in horizontal well drilling and multi-stage fracturing technology. It is not clear at present as to the timing and volumes of increased water use; however, there are indicators that the trend of declining oil production and water use for EOR development in conventional pools may reverse. Future plan updates will reflect updated production forecasts and adjust for any impact on the projected non-saline water use productivity for conventional oil.

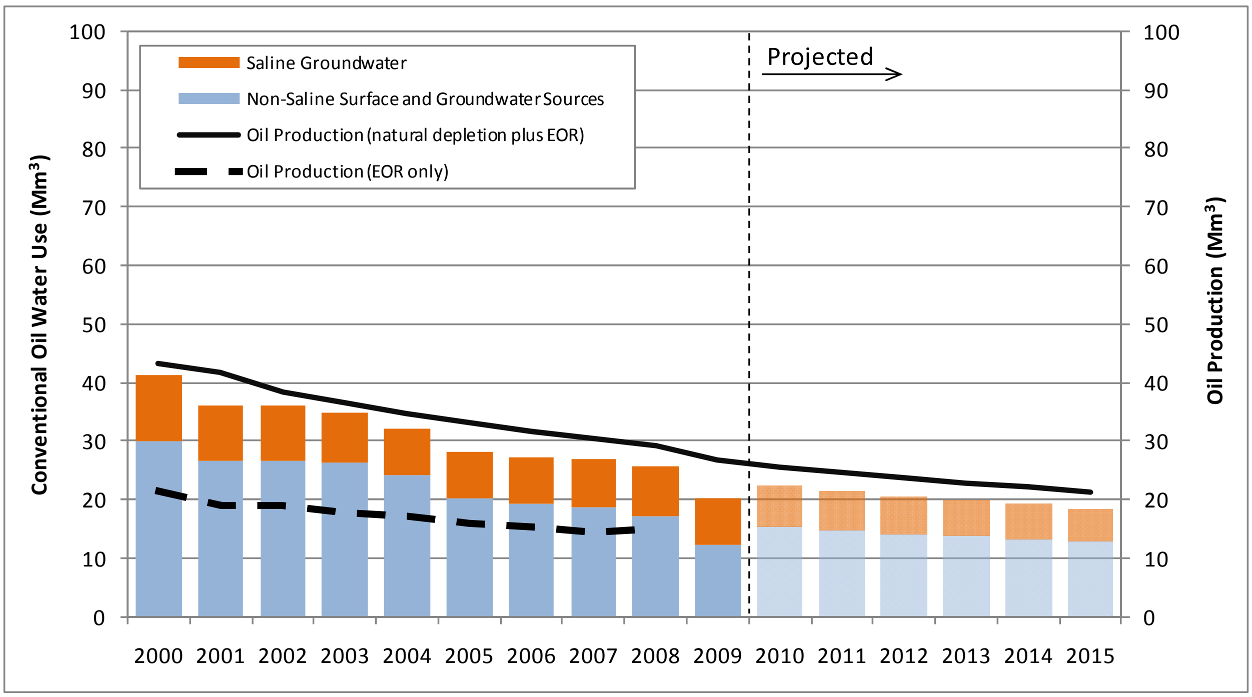


Figure 3-5: Conventional Oil and EOR Water Use Forecast (to 2015)

Well drilling and completions

The water use forecast for well drilling and completions does not distinguish between water sources because several water sources were used to compile the forecast. On average, about 8.3 Mm^3 per year are expected to be used, assuming 16,600 wells per year and 400 m^3 to 600 m^3 of water required per well. The forecast water use is shown in Figure 3-6. The forecast is presented as a range, due to the highly variable drilling depths and geological conditions across the province.

Some of the water used for deep wells may be saline groundwater. However, all of the estimated water use was included in the provincial total for projected non-saline water use.

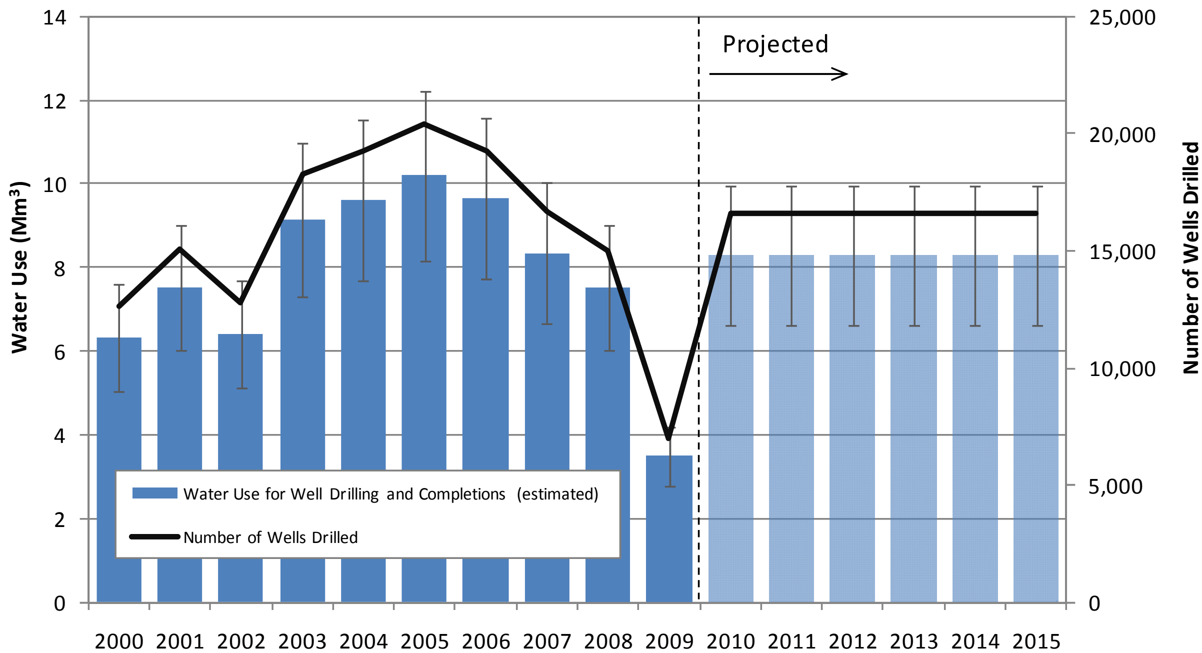


Figure 3-6: Well Drilling and Completions Water Use Forecast (to 2015)

Conventional and unconventional gas production

Water use forecasts for gas production were not included in the CEP plan because conventional gas production normally uses low amounts of water. Some current unconventional gas production either uses or produces water. For example, saline water is typically produced from Mannville Formation CBM projects, but CBM developments in the Horseshoe Canyon Formation do not produce significant volumes of water.

Shale gas is an emerging area in the upstream oil and gas sector. Shale gas production typically needs large volumes of water for drilling and completions. The low-permeability shale gas reservoirs require specialized completion techniques, including fracturing of the reservoir rock, to recover the resource. Each fracture requires 2,500 to 5,000 m^3 of water, and a typical well in the Horn River Basin in northeastern British Columbia uses an average of 60,000 m^3 of water (Horn River Basin Producers Group, 2010). Approximately 15-30% of this water is recovered within the first several months, and in some cases is reused or disposed of through deep well injection. While surface water is commonly used for the fracture treatments, alternatives are being evaluated. Production of water when the wells are completed is not an issue as the reservoirs produce dry gas.

At present, the Horn River Basin is the only commercial shale gas development in Canada. Production forecasts available at time of CEP plan development indicate that significant shale gas development is not likely to occur in Alberta until after 2015, though insufficient data is available to accurately predict the rate of implementation. As such, a water use forecast for shale gas development was not included in this CEP plan, but will be incorporated in future plan updates. In preparation for shale gas development in Alberta, CAPP is developing relevant water performance metrics that will improve CAPP's ability to assess current, and to forecast future, shale water use. Alberta Environment and the ERCB are working with industry to understand development pressures and regulatory response for development of shale gas reserves.

3.2 CEP Performance Measure

The selected performance measure for this CEP plan is non-saline water use productivity. This is defined as the volume of non-saline water used per volume of hydrocarbon produced. Overall CEP performance is reported as the projected non-saline water use productivity in 2015 compared to historical baseline water use. For the purpose of this CEP plan, the baseline years were selected as the average of 2002 to 2004, consistent with the Alberta Water Council's recommendations.

Baseline non-saline water use productivity

The projected non-saline water use productivity was compared to historical baseline conditions as a benchmark measure of the expected improvement in productivity. During the baseline period from 2002 through 2004, water use varied from 0.6 to 0.7 m^3 to about 3 m^3 of water per cubic metre of production, depending on the industry sector component. Historical water use for the sector components is noted below:

- Oil sands mining (Athabasca River withdrawal) water use was 3.18 m^3 of Athabasca River water per m^3 bitumen production (water:bitumen volume ratio). Oil sands mining (total non-saline) water use was 4.04 m^3 of non-saline water per m^3 bitumen production. Total non-saline water includes licenced collection of surface water and groundwater within mine areas in additional to Athabasca River withdrawal.
- In situ oil sands production had a non-saline water use productivity of 0.63. Including saline water use, the water use was 0.91 m^3 water per m^3 bitumen production. All production in the oil sands region includes thermal operations, but also includes CHOPS and other primary production.
- Conventional oil production, including EOR and other recovery methods, had a non-saline water use productivity of 0.70. Including saline water use, the water use was 0.94 m^3 water per m^3 oil production (water:oil). For comparison purposes, the water use for EOR only was 1.91 from 2002 to 2004, and 1.77 from 2005 through 2008 (Source: Petroleum Registry).
- Well drilling and completions were assumed to require about 500 m^3 per well on average for all wells in Alberta.

The non-saline water use productivity for other uses (e.g., gas processing) is not included because the water use is relatively small.

Projected non-saline water use productivity

Overall, the upstream oil and gas sector expects to see a 24% improvement in non-saline water use productivity by 2015 compared to the baseline years of 2002 to 2004. A summary is presented in Table 3-1. The historical and projected non-saline water use productivity is shown in Figure 3-7 for oil sands mining and in Figure 3-8 for in situ oil sands and conventional oil production. The fluctuations in historical and projected non-saline water use productivity shown in Figure 3-7 indicate lower productivity in years where there is a projected mine startup and improved productivity during non-startup years.

As the table and figures show, the improvement varies with the type of oil or bitumen production. In situ oil sands operations are expected to see the greatest productivity improvement: 47% by 2015 compared to the baseline years. This improvement is primarily attributable to recycling and the use of saline sources to meet increased water demands. Oil sands mining use of Athabasca River water is expected to improve by 28%, while oil sands mining total non-saline water use (including licenced collection of surface water and groundwater within mine areas) is expected to improve by 30%. The improvement in mining non-saline water use productivity is due in part to the recycling and reuse of water from tailings ponds.

Additional improvements to non-saline water use productivity may be possible for gas plants and for drilling and completion of wells, but not enough information was available to determine the expected improvement.

Table 3-1: Projected Non-saline Water Use Productivity

<table>
<tr><th rowspan="2">Activity</th><th colspan="3">Baseline (2002 to 2004)</th><th colspan="3">Projected (2015)</th><th rowspan="2">Improvement[3] (%)</th></tr>
<tr><th>Production (Mm^3 OE[1])</th><th>Water Use (Mm^3)</th><th>Productivity (m^3 water:m^3 oil/bitumen)</th><th>Production (Mm^3 OE)</th><th>Water Use (Mm^3)</th><th>Productivity (m^3 water:m^3 oil/bitumen)</th></tr>
<tr><td>Oil Sands Mining (Athabasca River water only)</td><td rowspan="2">35.9</td><td>114.2</td><td>3.18</td><td rowspan="2">70.7</td><td>162.5</td><td>2.30</td><td>28%</td></tr>
<tr><td>Oil Sands Mining (total non-saline water[2])</td><td>144.9</td><td>4.04</td><td>200.2</td><td>2.83</td><td>30%</td></tr>
<tr><td>Oil Sands In-Situ (non-saline water)</td><td>20.0</td><td>12.6</td><td>0.63</td><td>64.9</td><td>21.8</td><td>0.34</td><td>47%</td></tr>
<tr><td>Conventional Oil (non-saline water)</td><td>36.6</td><td>25.7</td><td>0.70</td><td>21.3</td><td>12.8</td><td>0.60</td><td>15%</td></tr>
<tr><td>Total</td><td>92.5</td><td>297.3</td><td>1.98</td><td>156.9</td><td>397.3</td><td>1.50</td><td>24%</td></tr>
</table>

Notes: 1. OE is oil equivalent; Mm^3 is millions of cubic metres.
2. Total non-saline water use for mining includes licenced collection of surface water and groundwater within mine areas as well as Athabasca River withdrawals
3. Projected non-saline water use productivity improvements do not include on-going site specific initiatives or new initiatives that may be initiated as a result of this CEP plan

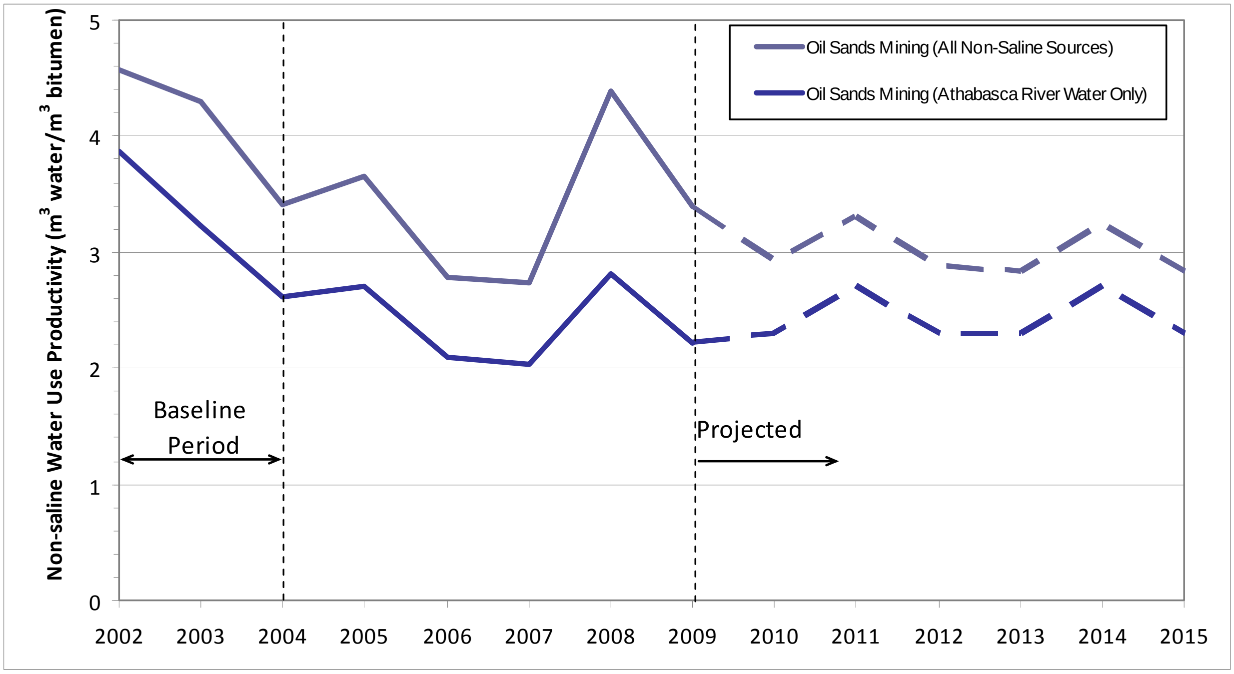


Figure 3-7: Historical and Projected Non-saline Water Use Productivity for Oil Sands Mining (2002 to 2015)

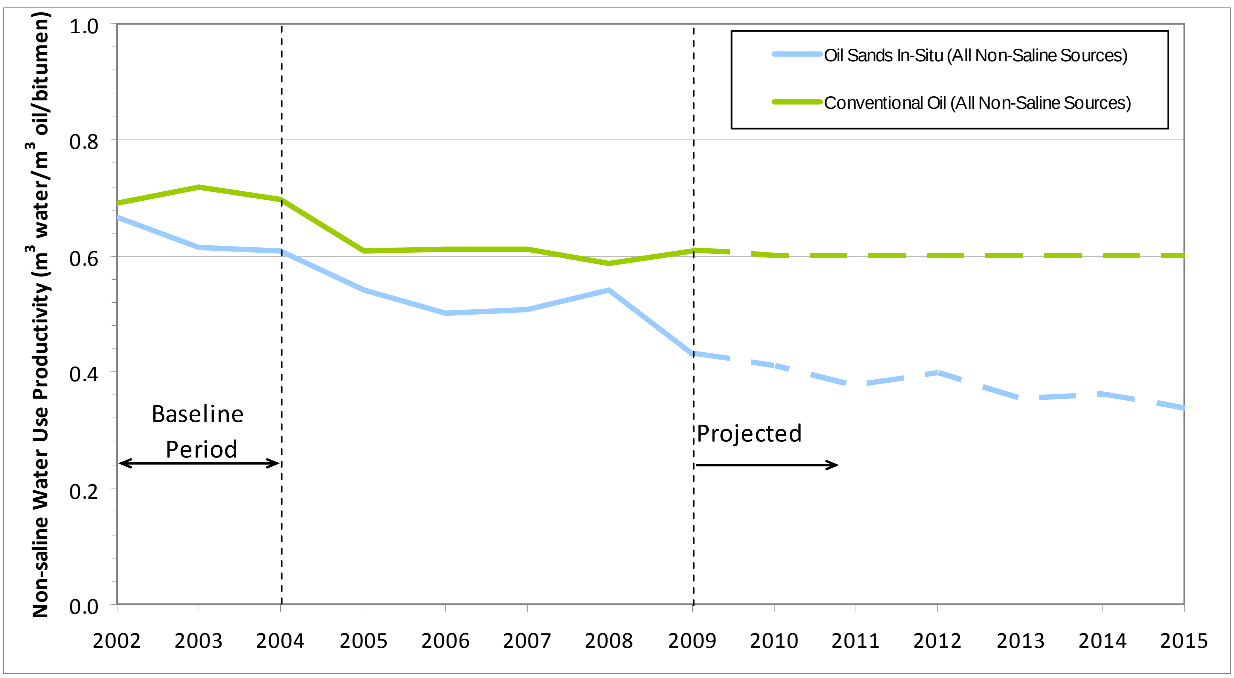


Figure 3-8: Historical and Projected Non-saline Water Use Productivity for Oil Sands In Situ and Conventional Oil (2002 to 2015)

3.3 Water Supply Considerations

Most of Alberta's water supply is located in the northern river basins, where demand from other sectors is low. In 2008, 98% of the upstream oil and gas industry's actual non-saline water use was in the northern half of Alberta – the Athabasca, Beaver/Churchill, Peace, and Hay/Liard River basins – which regulators consider to be "not regionally water-short." By contrast, the oil and gas industry uses very little water in the "water-short" or "potentially water-short" southern basins. Oil sands mining and in situ production represent more than 90% of the forecast sector water use in northern Alberta by 2015.

Some key considerations for future water supply are:

- Access to sufficient suitable saline water for oil sands in situ operations; and
- Seasonal Athabasca River water availability for oil sands mining.

The oil and gas industry has been preferentially increasing its use of saline water sources and is committed to meeting regulatory requirements to use this water source as much as possible. A large portion of the overall improvement in non-saline water use is due to increased recycling rates and the use of saline groundwater. Saline water aquifers currently provide large volumes to oil sands in situ operations and for conventional EOR production. This alternative water source is targeted for increased use over the next five years, provided that volumes and quality are sufficient to meet the demand in the location of future development.

Seasonal water availability for oil sands mining operations may also be a consideration due to regulatory requirements that limit the withdrawal of water from the Athabasca River during winter low flow conditions. Alberta Environment and Department of Fisheries and Oceans (DFO) have developed a framework to set seasonal withdrawal restrictions for the Athabasca River to help ensure protection of the aquatic ecosystem (Alberta Environment and DFO, 2007).

In the case of the Athabasca River, the framework currently limits the total river withdrawal downstream of Fort McMurray to as little as 8 m^3/s during unusually low winter flow conditions. By comparison, projected Athabasca River water use is expected to be about 5.1 m^3/s by 2015 for average climate conditions.

Another consideration for water supply planning is groundwater availability. Groundwater in Alberta is often monitored on a project-specific basis. Recently, draft Groundwater Management Frameworks have been developed by Alberta Environment for the Northern Athabasca Oil Sands Region, Southern Athabasca Oil Sands Region and Cold Lake-Beaver River Region. Similar plans will likely be developed for other key areas of the province. Cooperation and collaboration between industry and government is essential to improving knowledge and management of groundwater resources.

The upstream oil and gas sector's activity and water use in northern Alberta is consistent with the overall goal of the *Water for Life* strategy to target a balance of development in areas with available water.

4 Overview of Opportunities for CEP

4.1 Identification of CEP Opportunities

Many opportunities for water CEP exist within the upstream oil and gas sector. A number of these are already considered on a project-specific basis, and improvements are ongoing (see Section 2.4).

Based on the definitions for CEP, opportunities were categorized as follows:

- Conservation – Opportunities that may continue to use water, but would preserve valued water sources by using alternatives such as saline water, or by reusing poor quality water such as wastewater or produced water from other industrial or municipal activities.
- Efficiency – Opportunities that would decrease the overall water use, such as additional recycle water to reduce the requirements for makeup water.
- Productivity – Opportunities that would increase production of goods and services per unit of water used.

The CEP opportunities identified by the industry are listed in Table 4-1 and described in more detail in Appendix B. All three categories noted above are included in the list, from targeting less valuable water sources to applying technology to reduce water use or increase production without using additional water. The opportunities also include infrastructure or technology solutions to provide treatment or water storage to offset water withdrawals in times of lower supply (e.g., winter months).

Many of these potential opportunities are already being implemented by some producers, or are required by regulations. Others would require changes to the current regulatory management system before they can be considered or implemented. For example, because this industry is generally less sensitive than most other sectors to the quality of water it requires, upstream oil and gas has more flexibility in the water sources it can use. Thus, the sector could further target water sources that are relatively poorly-suited for providing drinking water or ecosystem functions. Prioritizing water sources in this way would expand on the current use of saline water to define additional source categories depending on water chemistry and concurrent uses.

A decision to implement any of the CEP opportunities should be informed by a project-specific assessment of net environmental benefit.

Table 4-1: CEP Opportunities

ID	Type: Conservation	Type: Efficiency	Type: Productivity	Potential opportunity	Comments (barriers, constraints, etc.)	Industry applicability: Waterflood	Conventional oil	(Un)conventional gas	Oil sands in situ	Oil sands mining
1	x			Redefine water quality regulations to prioritize use of lower quality non-saline water.	Require Alberta Environment to redefine water quality regulations to prioritize use of lower quality water by industry, as a means of conserving the highest quality water.	x	x	x	x	
2		x		Reuse municipal wastewater instead of diverting additional water.	Need to consider site-specific conditions. The water licence may need to be amended to change the return flow conditions.	x	x	x	x	
3		x		Consider alternative oil sands tailings technologies and management techniques that are less water-intensive.	A variety of technologies are currently being considered, researched and tested. The focus is currently on meeting similar but different reclamation goals for the ERCB.					x
4			x	Implement CO_2 injection to enhance recovery instead of injected water.	Cost, infrastructure and reservoir suitability are constraints. Pilot scale testing is ongoing.	x				
5	x			Consider alternatives to non-saline water for drilling or frac fluids.	Limited benefit for conventional drilling; greater potential benefit for shale gas. The installation of surface casing, which protects useable aquifers, requires the use of non-saline water.	x	x	x		
6	x			Use saline groundwater for pressure maintenance.	Already implemented; required for new licences to consider on a feasibility basis.	x	x			
7		x		Update equipment and equipment operating procedures for improved water efficiency (e.g., eliminate non-value added water use; review water cooling process).	Equipment that is more than 10 years old may be relatively inefficient in terms of water use.	x	x	x	x	x
8	x			Reuse oil sands mining wastewater streams for in situ makeup water, such as blowdown from upgraders or tailings pond water.	Currently done by some operations; requires infrastructure such as a pipeline. Opportunity is highly dependent on the availability of wastewater to the specific project and assurance of sufficient supply over the life of the project. .				x	x
9	x			Use saline water for steam generation at oil sands in situ thermal operations.	Cost- and energy-intensive. Already being done at some operations; required by existing regulations to consider this water source.				x	
10			x	Implement solvent injection to enhance recovery.	Limited commercialization; several pilots in place.				x	
11		x		Treat and reuse produced water, or water from other operations, that would otherwise be disposed of by injection.	Need to consider site-specific conditions.	x	x	x	x	
12			x	Implement in situ combustion to enhance recovery at oil sands in situ operations.	Technology is still at the pilot stage and will depend on reservoir characteristics. Research is continuing.				x	
13		x		Consider water treatment for waste/produced/saline water to be reused or released instead of disposal.	Currently implemented in the US for shale gas.	x	x	x	x	x
14		x		Convert to oil sands mining extraction methods that are not water-based.	Extraction technology at research development stage. Requires solvent disposal strategy.					x
15		x		Recycle, reuse or redistribute produced water, rather than disposing into the deep subsurface.	Potential for efficiencies due to seasonal availability/use. May need approval to reuse water instead of returning it to the environment.	x		x	x	
16	x			Use evaporator technology to treat blowdown at oil sands in situ operations.	Cost- and energy-intensive. Increased volumes of waste disposal.				x	
17		x		Reduce evaporation from ponds.	Relatively small potential for water use reduction, but may have other environmental benefits.					x
18			x	Add polymers to waterfloods for improved productivity.	The water quality needs to be compatible with the polymer additive or additional treatment is required prior to adding the polymer.	x				
19	x			Consider storage of water in aquifers for future use.	Seasonal advantage for water-short areas.			x	x	x
20	x			Consider surface water storage options	Seasonal advantage for sensitive winter low flow period (e.g., oil sands mining). Negative impact on land footprint.					x
21		x		Treat water to increase recycling rate from tailings ponds at oil sands mines.	Limited potential for improvements because tailings pore-space must be filled with water.					x
Total	9	9	4			11	8	9	13	10

4.2 Analysis of CEP Opportunities

The CEP opportunities presented in Table 4-1 were assessed roughly based on the following priorities:

- Non-saline water use productivity – Opportunities with greater potential increases in non-saline water use productivity.
- Net environmental benefits – Opportunities with concurrent net environmental benefits.
- Implementation availability – Opportunities that are readily available for implementation.

The opportunities were analyzed in a qualitative manner based on industry interpretation of the potential CEP value of each opportunity.

4.3 Recommended CEP Opportunities and Targets

Sector target

Overall, the sector aims to improve non-saline water use productivity by 24% by 2015, compared to 2002 to 2004. Actual productivity will vary in wet or dry years. The targeted improvement is between 15% and 47% depending on the type of oil or bitumen production. As a result of industry's proactivity, much of the targeted improvement in non-saline water use productivity has already been realized relative to the baseline year.

Recommended CEP opportunities

The recommended CEP opportunities will vary among specific operations and types of development. All of the CEP opportunities listed in Table 4-1 should be considered. In general terms, the following opportunities are interpreted to provide the most significant CEP gains:

- Target water sources that are less valuable for potable use or for ecosystem functioning. This requires new regulatory definitions for water sources that expand on the existing definitions for saline water.
- Reuse wastewater instead of diverting additional non-saline water, similar to the previous opportunity. This may reduce return flows from these other uses, but would effectively increase the overall recycling of water to avoid diversions of non-saline water.
- Consider alternative oil sands tailings technologies and management techniques that are less water-intensive. Alternative tailings technologies are currently considered at all existing and planned mines with a focus on reclamation performance.
- Inject CO_2 instead of water to enhance recovery of conventional oil. This is expected to have a relatively small impact on sector water use, but a stronger net environmental benefit. The challenges affecting the availability of cost-effective CO_2 suggest that the viability of this option may extend beyond the scope of the current plan.
- Consider alternatives to non-saline water for drilling or frac fluids, such as saline water or other technologies. This opportunity may have a relatively small impact on the sector's water use, but technologies are readily available and there could be strong local environmental benefits.

- Use saline groundwater for pressure maintenance. The relative benefits may be locally strong, provided that saline groundwater is available in sufficient quantities.
- Update equipment and equipment operating procedures to improve water efficiency. This opportunity is site-specific, but could significantly improve water efficiency at older operations that may be using relatively inefficient systems for cooling, boiling, pumping, or water treatment.
- Reuse oil sands mining wastewater streams for in situ makeup water, such as blowdown from upgraders or tailings pond water. Some companies have already implemented a form of this reuse opportunity. Further implementation may depend on the availability of surplus water at oil sands mines for use at in situ operations. Currently, oil sands mines do not maintain surplus water on-site.
- Use saline water for steam generation at oil sands in situ thermal operations. This is now implemented where possible, in line with ERCB regulations, but supplies of this alternative water source could be limited in some locations.
- Implement solvent injection to enhance recovery at in situ oil sands operations. Several pilots are in place for this relatively new technology, and there is potential to improve production without using additional water. This technology is also expected to reduce CO_2 emissions.

5 CEP Plan Implementation, Monitoring and Participation

5.1 Implementation and Schedule

Several potential initiatives will be part of the implementation of this CEP plan, including:

- Dissemination of the plan to operating companies and delivering training workshops.
- Use of CAPP's Responsible Canadian Energy™ program metrics for mandatory reporting of water use and production to support the calculation of industry's non-saline water use productivity and tracking of improvements in water CEP over time.
- Continued research and development.
- Other technology transfer initiatives, such as:
  - Annual CAPP Environmental Issues Seminar
  - Biannual CONRAD workshop

The goal of the implementation plan is to provide individual companies with the tools to evaluate the non-saline water use productivity of individual projects in order to promote project-specific water CEP opportunities, and to help explain the potential energy savings or other benefits of water CEP to companies and the public. Many companies are already implementing water CEP initiatives, but improvements are often not communicated to stakeholders or the general public.

Actions to be taken as part of the water CEP plan will be implemented within one year of the plan's submission. Other actions by individual companies will be ongoing and tracked as appropriate.

5.2 Integration with Other Plans

The CEP plan's implementation will be integrated with existing CAPP initiatives (CAPP Responsible Canadian Energy Program™), as well as existing technology transfer events such as the CONRAD workshops.

Companies are also expected to continue their involvement with watershed groups to help develop and promote watershed management plans throughout Alberta.

5.3 Monitoring and Reporting

Performance measurement

The selected performance measure for future improvement of water CEP in this sector is the ratio of non-saline water use to production of oil or bitumen. This non-saline water use productivity measure is also recommended by the Alberta Water Council. It represents a normalized metric for tracking the efficiency of industry water use, and it can be combined with other management systems at the local or regional level to ensure equitable water allocation.

Monitoring and auditing

Monitoring information related to water use is collected and managed by Alberta Environment and the ERCB or by industry organizations such as CAPP. Currently, all licensees are required to retain records of water use. Most large municipal, irrigation, commercial, and industrial users are required to report their water use to Alberta Environment. For smaller licences, Alberta

Environment has developed a voluntary online reporting system to obtain additional water use information. Companies are encouraged to submit all of their water use data electronically to the province's Water Use Reporting System.

All non-saline water use by the upstream oil and gas sector is reported to Alberta Environment according to the terms and conditions listed in the operator's diversion licence (usually for drilling and/or completions), *Water Act* licence, or *Water Resources Act* licence. Water use and water production measurements for oil and gas operations are also managed through the ERCB. These different types of water uses primarily include tracking and disposition of produced water for conventional oil and gas, and recycling in EOR or thermal in situ operations.

Produced water and saline groundwater used for pressure maintenance or for thermal in situ oil sands development are currently unregulated by Alberta Environment, although these uses are typically reported to the ERCB. ERCB regulations presently require that produced water be injected downhole after it has been practically used to its maximum.

Reporting

The sector intends to revisit and update current and projected non-saline water use productivity at least once every five years. The report will describe any major changes in the industry or to standard practices that may affect non-saline water use productivity.

The goal is to generate this report using Alberta Environment's monitoring of water use data, combined with ERCB monitoring of annual production data. Industry intends to work with Alberta Environment and the ERCB to improve the licensing and data reporting process so that it is more accessible and aligns with the water use categories in the CEP plan.

Evaluation and continuous improvement

The sector will comply with all regulations related to water, and will continue to pursue improvements in water CEP. As well, the water CEP plan will be updated as recommended by the Alberta Water Council.

The updates and continuous improvements will be managed through CAPP and related organizations, such as the OSDG.

5.4 Participation and Accountability

Participation and accountability of the sector will occur through the following mechanisms:

- Mandatory reporting of water use as a requirement of water licences and encouraging industry members to report electronically.
- Mandatory reporting of water use data through the CAPP Responsible Canadian Energy™ program.
- Measurement of a company's performance through voluntary implementation of the CAPP Responsible Canadian Energy™ Water Management Guideline.
- Participation in water management initiatives of watershed groups and industry organizations.

6 Summary

This plan documents the intent of the upstream oil and gas sector with respect to water CEP. This sector comprises the upstream component of the oil and gas sector, and the oil sands component of the mining and oil sands sector. Overall, the sector expects growth in oil sands mining and in situ production, increased total water demand, and increased non-saline water use productivity. The sector expects to use almost 250 Mm^3 per year of non-saline water by 2015, of which about two-thirds (or 162 Mm^3 per year) will consist of Athabasca River water withdrawn for oil sands mining. Saline water use is projected to be about 45 Mm^3 by 2015.

The upstream oil and gas sector has already realized significant, quantifiable water productivity gains compared to the baseline years of 2002 to 2004. To date, most improvements in water use have been achieved by increasing recycling rates and replacing non-saline water use with saline groundwater in thermal in situ and conventional EOR projects (Alberta Environment, 2003b). These achievements have been made possible through technological improvements and decision-making that has preferentially chosen saline water. Although the most obvious CEP opportunities with the largest gains have already been implemented, further improvements are expected.

The selected performance measure for documenting water CEP improvements is the projected non-saline water use productivity compared to the selected baseline years of 2002 to 2004. Components of the sector are expected to improve productivity by 15% to nearly 50% by 2015 as compared to the baseline years, as noted below:

- Oil sands mining (Athabasca River water only) = 28%
- Oil sands mining (total non-saline water) = 30%
- Oil sands in situ = 47%
- Conventional oil (including EOR) = 15%

The projected improvement in non-saline water use productivity will depend on: the availability and treatability of saline water sources for in situ and EOR operations; a net environmental benefit of using saline water sources; the timing of new oil sands projects; and the opportunities selected by individual producers.

Producers have a variety of potential CEP opportunities from which to choose. These opportunities will need to be considered and implemented, if appropriate, by individual producers based on site-specific conditions. Some of the opportunities are already being implemented and have contributed to significant CEP improvements.

The upstream oil and gas sector is also committed to reporting water CEP information in terms of selected water use and production measures, in conjunction with Alberta Environment and the ERCB, through CAPP and other organizations.

The CEP plan is expected to be updated using the overall methodology presented in this plan, based on production forecasts and industry average non-saline water use productivity.

7 Glossary and Acronyms

AOSTRA – Alberta Oil Sands Technology and Research Authority.

API – American Petroleum Institute.

AUPRF – Alberta Upstream Petroleum Research Fund.

AWRI – Alberta Water Research Institute.

Base of groundwater protection (BGWP) – The BGWP is the best estimate of the depth at which saline groundwater is likely to occur. Water above the BGWP is protected by regulation.

Benchmark – The value for an indicator that has some defined environmental significance (scientific) or the value for an indicator that demonstrates achievement of best practice (corporate).

Best management practices (BMPs) - Management practices or techniques recognized to be the most effective and practical means for meeting goals, while minimizing adverse environmental and other effects.

Bitumen – Petroleum in semi-solid or solid forms.

Blowdown – Removal of liquids or solids from a process.

CAPP – Canadian Association of Petroleum Producers.

CBM – Coalbed methane, which is natural gas generated and trapped in coal seams. Also called 'natural gas in coal' (NGC).

CEMA – Cumulative Environmental Management Association.

CEP – Conservation, efficiency and productivity.

CHOPS – Cold heavy oil production with sand.

CO_2 – Carbon dioxide.

CONRAD – Canadian Oil Sands Network for Research and Development.

Conservation – Any beneficial reduction in water use, loss or waste, or practices that improve the use of water to benefit people or the environment.

Conventional (crude) oil – Petroleum found in liquid form, flowing naturally or capable of being pumped without further processing or dilution.

CSS – Cyclic Steam Stimulation method of oil sands in situ bitumen extraction.

Density – The heaviness of crude oil, indicating the proportion of large, carbon-rich molecules, generally measured in kilograms per cubic metre (kg/m^3) or degrees on the API gravity scale; in Western Canada oil up to 900 kg/m^3 is considered light to medium crude; oil above this density is considered heavy oil or bitumen.

DFO – Department of Fisheries and Oceans Canada.

Downstream (oil and gas activities) – The refining and marketing sector of the petroleum industry.

Ecosystem – A dynamic complex of plant, animal and micro-organism communities and their non-living environment interacting as a functional unit.

Efficiency – The accomplishment of a function, task, process or result with the minimal amount of water feasible. Efficiency is an indicator of the relationship between the amount of water required for a particular purpose and the quantity of water used or diverted.

Enhanced oil recovery (EOR) – Any method that increases oil production by using techniques or materials that are not part of normal pressure maintenance or water flooding operations. For example, natural gas or water can be injected into a reservoir to "enhance" or increase oil production. Enhanced oil recovery operations do not include oil sands operations.

EPEA – Environmental Protection and Enhancement Act.

ERCB – Energy Resources Conservation Board.

GRI – Global Reporting Initiative.

Groundwater – Water located beneath the ground surface.

Heavy crude oil – Oil with a gravity below 28 degrees API.

Instream flow needs (IFN) – the scientific recommendation for water requirements to achieve ecological protection of a river.

Injection well – A well used for injecting fluids (air, steam, water, natural gas, gas liquids, surfactants, alkalines, polymers, etc.) into an underground formation for the purpose of increasing recovery efficiency.

In situ – In the original location or position. In oil sands production, in situ recovery refers to various methods used to recover deeply buried bitumen deposits, including steam injection, solvent injection and firefloods.

Kbpd – thousands of barrels per day of production.

Life cycle assessment – A concept and a methodology to evaluate the environmental effects of a product or activity holistically, by analyzing the entire life cycle of a particular material, product technology, service or activity.

Light crude oil – Liquid petroleum that has a low density and flows freely at room temperature.

Makeup water – Additional water required for a process to makeup for losses such as blowdown or evaporation.

Medium crude oil – Liquid petroleum with a density between that of light and heavy crude oil.

Methane – The principal constituent of natural gas; the simplest hydrocarbon molecule, containing one carbon atom and four hydrogen atoms.

Midstream (oil and gas activities) – The processing, storage and transportation sector of the petroleum industry.

n/a – not available.

Non-saline water – Water that has a total dissolved solids content less than or equal to 4,000 mg/L.

Non-saline water use productivity – The non-saline water use per unit production, in terms of water:bitumen or water:oil.

NRTEE – National Round Table on the Environment and the Economy.

OE – Oil equivalent

Oilfield injection – The injection of non-saline or saline water, or non-water alternatives, for the purpose of maintaining or increasing the amount of recoverable hydrocarbon; i.e., one type of enhanced recovery method.

Oil sands – Naturally-occurring deposits of sand, clay or other minerals saturated with bitumen, found mainly in the Athabasca, Peace River and Cold Lake areas of Alberta.

Operator – The company or individual responsible for managing an exploration, development or production operation.

OSDG – Oil Sands Developers Group, an industry association of oil sands bitumen producers.

OSTRF – Oil Sands Tailings Research Facility.

Payback – The amount of time taken to break even on an investment or to recover the initial investment based on the future benefits, usually calculated without accounting for the time value of money.

Petroleum Registry of Alberta – Energy sector databases jointly managed by the Government of Alberta, ERCB, CAPP and SEPAC (www.petroleumregistry.gov.ab.ca/).

Porewater – The water that fills spaces between grains of solid material.

Potable water – Water suitable for human consumption, used for drinking, cooking and other domestic use. Health Canada defines potable water as containing less than 500 mg/L total dissolved solids.

Produced water – Any water that is produced and released or disposed as a result of oil and gas activity.

Productivity – Refers to the amount of non-saline water required to produce a unit of any good, service, or societal value.

Primary recovery – The production of oil and gas from reservoirs using the natural energy available in the reservoirs and pumping techniques.

RAMP – Regional Aquatics Monitoring Program.

RCE – CAPP's Responsible Canadian Energy™ program.

Recycle water– The process of using water multiple times for similar purposes.

Reuse water – The process of using water that has already been used for one purpose, such as produced water, and using the water one or more additional times for other purposes.

Return flow – Water that is included in an allocation and is expected to be returned to a water body after use and may be available for reuse, although the water quality characteristics may have changed during use.

Royalty – The owner's share of production or revenues retained by government or freehold mineral rights holders. In natural gas operations, the royalty is usually based on a percentage of the total production.

SAGD – Steam Assisted Gravity Drainage in situ bitumen production method. A recovery technique for extraction of heavy oil or bitumen that involves drilling a pair of horizontal wells one above the other; one well is used for steam injection and the other for production.

Saline groundwater – Water that has total dissolved solids content exceeding 4,000 mg/L.

SEPAC – Small Explorers and Producers Association of Canada.

Shale – Rock formed from clay.

SSRB – South Saskatchewan River Basin.

Stakeholders – Industry activities often affect surrounding areas and populations. People with an interest in these activities are considered stakeholders. They may include nearby landowners, municipalities, Aboriginal communities, recreational land users, other industries, environmental groups, governments and regulators.

Steam injection – An improved recovery technique in which steam is injected into a reservoir to reduce the viscosity of the crude oil.

Surface water – Water located above ground (e.g., rivers, lakes, wetlands).

Tailings – Materials remaining suspended in water after bitumen is separated from oil sand.

TDL – Temporary diversion licence.

TDS – Total dissolved solids.

Tertiary recovery – The third major phase of crude oil recovery that involves using more sophisticated techniques, such as steam flooding or injection of chemicals, to increase recovery.

Upstream – The companies that explore for, develop and produce Canada's petroleum resources are known as the upstream sector of the petroleum industry.

Water allocation – Amount of water that can be diverted for use, as set out in water licences and registrations issued in accordance with the *Water Act.*

Water:bitumen – Volume ratio of water use to bitumen production.

Water diversion (or withdrawal) **–** Describes the amount of water being removed from a surface or groundwater source, either permanently or temporarily.

Water:oil – Volume ratio of water use to oil production.

Water-short – A region of watershed that is potentially short of water, with a relatively high volume of water allocation compared to the actual water volume from stream flow.

Water use – Net water use or the difference between the amount of water diversion and the return flow. For the purpose of this CEP Plan, return flows have been neglected. Therefore, the water use described in this report is equivalent to the water diversion.

Waterflood – A type of enhanced oil recovery in which water is pumped into conventional oilfield reservoirs.

Withdrawal – A volume of water removed under licence from a water source.

WPAC – Watershed Planning and Advisory Council.

8 References

Information and data used to prepare this document came from many sources, some of which are not listed in the references because they are not compiled into one specific publication. Nevertheless, all the information is available through public sources.

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Appendix A Summary of Key Water Legislation and Guidance

Table A-1: Alberta Environment Regulatory Framework

Title	Purpose/Description	Policy/Guideline/ Approval Mechanism	Industry Applicability	Link to Document
ACTS/REGULATIONS				
Water Act	Governs water diversions, developments, volumes and usage (i.e., borrow pit exemption limit is 6250 m^3)	Legislation	All	http://www.qp.alberta.ca/574.cfm?page=w03.cfm&leg_type=Acts&isbncln=9780779733651
	Approval for specific point water diversion locations and volumes	Licence	All	http://www.qp.alberta.ca/index.cfm
	Temporary approval for point water diversion locations and volumes	Temporary Diversion Licence (TDL)	All	http://www.qp.alberta.ca/index.cfm
	Manages allocations within specified river basins	Bow, Oldman and South Saskatchewan river basin water allocation order	Specific watersheds	http://www.qp.alberta.ca/574.cfm?page=2007_171.cfm&leg_type=Regs&isbncln=9780779725748
Water (Ministerial) Regulations	Supports *Water Act* legislation	Regulation	All	http://www.qp.alberta.ca/index.cfm
Water (Offences and Penalties) Regulation	Supports *Water Act* legislation	Regulation	All	http://www.qp.alberta.ca/index.cfm
Environmental Protection and Enhancement Act	Promotes the protection, enhancement and wise use of the environment	Legislation	All	http://www.qp.alberta.ca/index.cfm
	Sections relate to the use, release, chemistry and disposal of non-saline water.	Part 5 Release of Substances Part 6 Conservation and Reclamation Part 7 Potable Water Part 9 Waste Minimization, Recycling and Waste Management	All	http://www.qp.alberta.ca/index.cfm

Title	Purpose/Description	Policy/Guideline/ Approval Mechanism	Industry Applicability	Link to Document
CODES OF PRACTICE				
Codes of Practice (*Water Act*)	Codes regulate activities under the *Water Act* that would normally require an approval to be obtained. The Codes set out the standards and conditions to be met to ensure the activity minimizes the disturbance and impact on the environment when undertaking or conducting the activities governed by the Codes.	Code	Code-specific	
	This Code of Practice applies to hydrostatic testing for the purpose of pressure testing a pipeline to determine its integrity. For diversions of water in excess of 30000m^3 a water diversion licence is required. The release of hydrostatic test water is regulated under the Code of Practice for the Release of Hydrostatic Test Water from Hydrostatic Testing of Petroleum Liquid and Gas Pipelines (EPEA).	Temporary Diversion of Water for Hydrostatic Testing		http://www.environment.alberta.ca/1398.html
	Establishes the objectives, standards and conditions to be met when undertaking the activity of constructing or removing a pipeline or telecommunication crossing of a water body.	Pipelines and telecommunications lines crossing a water body		http://www.environment.alberta.ca/1398.html
	Establishes the objectives, standards and conditions to be met when undertaking the activity of constructing or removing a watercourse crossing.	Watercourse crossing		http://www.environment.alberta.ca/1398.html
	Establishes the objectives, standards and conditions to be met when undertaking the activity of constructing or removing an outfall structure.	Outfall structures on waterbodies		http://www.environment.alberta.ca/1398.html
Codes of Practice (EPEA)	Codes regulate activities under EPEA that would normally require an approval to be obtained. The Codes set out the standards and conditions to be met to ensure the activity minimizes the disturbance and impact on the environment when undertaking or conducting the activities governed by the Codes.	Code		
	Governs the release of water from hydrostatic testing. Volumes >1000 m3 require a registration from Alberta Environment.	Release of Hydrostatic Test Water from Hydrostatic Testing of Petroleum Liquid and Gas Pipelines		http://environment.alberta.ca/3.html

Title	Purpose/Description	Policy/Guideline/ Approval Mechanism	Industry Applicability	Link to Document
	Establishes water quality sampling of water contained in the pit prior to usage or release to the surrounding environment.	Pits		http://environment.alberta.ca/3.html
	Outlines implementation of groundwater monitoring systems.	Landfills		http://environment.alberta.ca/3.html
GUIDELINES/POLICIES				
Guidelines (*Water Act*)	Provide direction on activities and application designs.	Guide		
	Guideline for the required information for groundwater diversions and licensing.	Groundwater Evaluation Guideline	All	http://www.environment.alberta.ca/1949.html
	Places remediation targets on concentrations of chemicals in groundwater	Alberta Soil and Groundwater Remediation Guidelines (Tier 1 and 2)	All	http://environment.alberta.ca/777.html
	Management tool for water volumes for industry	Water Allocation Transfer Under a Licence	All	http://www.environment.alberta.ca/01653.html
Water For Life Strategy (and Renewal)	Designed to recommend a set of objectives and targets for the province to support sustainable water management	Overarching strategy		http://www.waterforlife.alberta.ca/
	Supports the conservation and management of water to prevent excess use of water during enhanced recovery of hydrocarbon resources. Establishes information required to apply for non-saline water for industrial use.	Water Conservation and Allocation Policy for Oilfield Injection	EIA based activities	http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_Policy.pdf
Standards and Guidelines for Coalbed Methane (CBM)	Summarizes the rules and processes that are currently in place to guide CBM development where non-saline water is involved.	Guidelines for Groundwater Diversion for Coalbed Methane/Natural Gas in Coal Development	CBM	http://environment.gov.ab.ca/info/library/7834.pdf
	Associated guideline for "Alberta Environment Guidelines for Groundwater Diversion for Coalbed Methane/Natural Gas in Coal Development". Requires mandatory collection of baseline water quantity and quality data from nearby water wells prior to drilling CBM wells.	Standard for Baseline Water-Well Testing for Coalbed Methane/Natural Gas in Coal Operations	CBM	http://environment.alberta.ca/documents/Standard_for_Baseline_Water-Well_Testing_for_CBM_Apr2006.pdf

Title	Purpose/Description	Policy/Guideline/ Approval Mechanism	Industry Applicability	Link to Document
Water Conservation Objectives	Relate to the volume and quality of water to remain in rivers for the protection of its aquatic environment. They are flow targets under the *first-in-time, first-in-right* priority water allocation system and apply to all new licences and existing licences with a retrofit provision.	Various	All	http://environment.alberta.ca/01724.html
Wetland Policy	Policy provides a strategic framework for conserving, restoring and protecting Alberta's wetlands.	*Water Act*	All	Anticipated release in 2012
Framework for Water Management Planning	The Framework outlines the process for water management planning and the components required for water management plans in the province. It applies to all types of waterbodies, including streams, rivers, lakes, aquifers and wetlands, and takes a holistic approach. It is general guidance for the planning process.		All	http://environment.gov.ab.ca/info/library/6367.pdf
Athabasca River Water Management Framework	Diversions from the river are based on rigourous in-stream objectives set by the government	Alberta Environment	Mining	http://www.environment.alberta.ca/01229.html
Cumulative Effects Management (CEM) Environmental Plan	A cumulative effects management framework will be modelled with three projects – one in the Industrial Heartland, one in east central Alberta and one in southern Alberta.	Alberta Environment	All - Industrial Heartlands area	http://environment.alberta.ca/documents/CEM_Environmental_Plan.pdf
Water Management Framework for the Industrial Heartland and Capital Region	Completing engineering study to recycle/reclaim wastewater, governance regarding the best way to deal with additional facilities for reclaiming wastewater, municipal and industrial wastewater reuse. Engineering study looking at 5 options for recycling and reuse. Regional wastewater treatment plants possible so governance rules will be required. Eng study to be completed in mid to end 2010. No produced water recycling (mostly refineries, chemical plants, municipal wastewater plants). Area around Scotford. Framework was approved December 2007.	Alberta Environment	ISBN: 9780778568070 Terms of reference:	http://environment.gov.ab.ca/info/library/7864.pdf

Table A-2: ERCB Regulatory Framework

Title	Policy/Guideline/ Approval Mechanism	Purpose/Description	Industry Applicability	Link to Document
ACTS				
Oil and Gas Conservation Act	Section 37, 39, 41	Control/regulate the production of oil, gas and water; disposal of water	All	http://www.ercb.ca/docs/requirements/actsregs/ogc_act.pdf
***Oil and Gas Conservation Act* Regulations**	Section 2.120, 6.050, 6.080, 8.040, 8.052(3), 8.060	Water pollution control, spacing with respect to waterbodies	All	http://www.ercb.ca/docs/requirements/actsregs/ogc_reg_151_71_ogcr.pdf
DIRECTIVES				
Determination of Water Production at Gas Wells	Directive 004	Requirements for the measurement and reporting of produced water from gas wells. No difference between non-saline and saline water (>4000 mg/L). Non-saline water may require *Water Act* licence.	Gas	http://www.ercb.ca/docs/documents/directives/Directive004.pdf
Shallow Fracturing Operations – Restricted Operations	Directive 027	Places controls on fracturing when developing shallow gas reservoirs less than 200 metres deep. Includes restrictions to protect adjacent water wells and shallow aquifers.	Shallow Gas	http://www.ercb.ca/docs/documents/directives/Directive027.pdf
Baseline Water Well Testing Requirement for Coalbed Methane Wells Completed Above the Base of Groundwater Protection	Directive 035	Outlines testing requirements for CBM completed above the base of groundwater protection. This is similar to Alberta Environment's "Standard for Baseline Water-Well Testing for Coalbed Methane/Natural Gas in Coal Operations"	CBM	http://www.ercb.ca/docs/documents/directives/directive035.pdf
Drilling Blowout Prevention Requirements and Procedures	Directive 036	Prohibits the use of oil-based drilling fluids (or any other potentially toxic drilling additive) when drilling above the base of groundwater protection depth.	All	http://www.ercb.ca/docs/documents/directives/Directive036.pdf
Measurement, Accounting, and Reporting Plan (MARP) Requirement for Thermal Bitumen Schemes	Directive 042	Water balancing including injection	Thermal	http://www.ercb.ca/docs/documents/directives/directive042.pdf

Title	Policy/Guideline/ Approval Mechanism	Purpose/Description	Industry Applicability	Link to Document
Well Logging Requirements – Surface Casing Interval	Directive 043	Sets out requirements for logging the surface casing interval on all new wells in order to provide additional information for shallow groundwater mapping and characterization.	All	http://www.ercb.ca/docs/documents/directives/directive043.pdf
Requirements for the Surveillance, Sampling, and Analysis of Water Production in Oil and Gas Wells Completed Above the Base of Groundwater Protection	Directive 044	Sets out the actions that well licensees must follow and that the ERCB will take when total water volumes equal to or greater than 5 cubic metres per calendar month (m^3/month) are produced from any well completed above the base of groundwater protection.	All	http://www.ercb.ca/docs/documents/directives/directive044.pdf
Injection and Disposal Wells - Well Classifications, Completions, Logging, and Testing Requirements	Directive 051	Clarifies completion, logging, testing, monitoring, and application requirements for injection and disposal wells. Specifies procedures and practices designed to protect the subsurface environment, including all usable groundwater and hydrocarbon-bearing zones.	All	http://www.ercb.ca/docs/documents/directives/directive056.pdf
Storage Requirements for the Upstream Petroleum Industry	Directive 055	Outlines criteria for surface water discharge applicable to upstream petroleum sites that are regulated by the ERCB or jointly Alberta Environment/ERCB and don't have an EPEA approval.	All	http://www.ercb.ca/docs/documents/directives/directive056.pdf
Energy Development Applications and Schedules	Directive 056	Outlines wellhead setbacks from waterbodies and well spacing requirements.	All	http://www.ercb.ca/docs/documents/directives/directive056.pdf
Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes	Directive 074	Sets out the requirements of the regulation of tailings ponds associated with mineable oil sands.	Mining	http://www.ercb.ca/docs/documents/directives/directive074.pdf

Table A-3: Other Legislation and Governance

Title	Administrator	Purpose/Description	Industry Applicability	Link to Document
PROVINCIAL/MUNICIPAL				
Public Lands Act	Alberta Sustainable Resource Development (SRD)	Section 3 provides for provincial ownership of beds and shores of permanent and naturally occurring waterbodies. Approvals under this Act are required for shoreline modifications or encroachments on bed and shore	All	http://www.qp.alberta.ca/documents/Acts/P40.pdf
Surveys Act	Alberta Sustainable Resource Development (SRD)	Section 17(3) defines the location of the legal bank and the extent of the bed and shore of a waterbody (see definition on page 4)	All	http://www.qp.alberta.ca/documents/Acts/S26.pdf
***Alberta Land Stewardship Act* (ALSA)**	Alberta Sustainable Resource Development (SRD)	Creates the legal authority to implement the Land Use Framework. The framework establishes seven new land-use regions and the requirement to develop a regional plan for each: Lower Athabasca, Lower Peace, North Saskatchewan, Red Deer, South Saskatchewan, Upper Athabasca, and Upper Peace. Cumulative effects management will be used at the regional level to manage the impacts of development on land, water and air.	All	http://www.qp.alberta.ca/documents/Acts/A26P8.pdf http://www.landuse.alberta.ca/
Bylaws	Municipal	Bylaws can include riparian protection, water use and water use restrictions. These are developed and enforced by individual municipalities.	Municipality-specific	
FEDERAL				
***Canadian Environmental Protection Act* (CEPA)**	Environment Canada	Parent legislation for CCME guidelines. Authorizes the collection of information for pollution releases to air, water and land (NPRI)	All	http://www.ec.gc.ca/lcpe-cepa/default.asp?lang=En&n=24374285-1
Migratory Birds Convention Act	Environment Canada	Prevents destruction of bird nesting habitat	All	http://laws.justice.gc.ca/en/M-7.01/
***Canadian Environmental Assessment Act* (CEAA)**	Canadian Environmental Assessment Agency	Outlines the environmental process for federal involvement.	All	http://laws.justice.gc.ca/eng/C-15.2/page-1.html
Canadian Environmental Quality Guidelines	Canadian Council of Ministers of the Environment (CCME)	Outlines the water quality parameters for the protection of freshwater aquatic life, protection of recreational water quality and protection of agricultural water uses.	All	http://ceqg-rcqe.ccme.ca/

Title	Administrator	Purpose/Description	Industry Applicability	Link to Document
Fisheries Act	Department of Fisheries and Oceans (DFO)	Prevents destruction of fish habitat	All	http://laws.justice.gc.ca/en/f-14
Navigable Waters Protection Act	Transport Canada	Prevents impairment to navigation	All	http://laws.justice.gc.ca/en/N-22/index.html
Water Management Framework: Instream Flow Needs and Water Management System for the Lower Athabasca River	Alberta Environment and Department of Fisheries and Oceans	Outlines water management criteria for the mineable oil sands.	Oil sands mining	http://environment.alberta.ca/documents/Athabasca_RWMF_Technical.pdf
ISO 14001 (environmental management)	International Organization for Standardization (ISO)	Voluntary commitment to compliance for environmental management (i.e., water monitoring, spill response, etc)	All	http://www.iso.org/iso/iso_14000_essentials

Table A-4: Licences and Approvals

Legislation/Regulations	Approval Mechanism	Purpose/Description	Industry Applicability	Link to Document
Water Resources Act	*Water Resources Act* Licence	Licences manage the volumes and rates of consumed water which can be diverted. Outlines the use of the water. Diversion volumes and rates must be reported annually to Alberta Environment. Licences exist in perpetuity.	All	http://environment.alberta.ca/1057.html
Water Act	*Water Act* Licence	Licences manage the volumes and rates of water *that is consumed* which can be diverted. Defines the use of the water. Diversion volumes and rates must be reported annually to Alberta Environment. Licences have expiration.	All	http://environment.alberta.ca/1057.html
	Water Act Temporary Diversion Licence (TDL)	Temporary licences with diversion volumes, rates and timing restrictions. Licences can exist for a one year but often last only a few weeks to accommodate exploration activities.	All	
	Water Act Approval	The approval permits the diversion of water for *non-consumption* activities. An example of non-consumable water diversions would be dewatering a shallow water table to build infrastructure.	Non-consumable water projects.	
Environmental Protection and Enhancement Act	EPEA Approval	Governs water quality release, disposal of chemically influenced water and requires monitoring and reporting of industrial/wastewater runoff, groundwater and surface water quality. Diversion volumes are governed under licences.	All	http://environment.alberta.ca/1057.html

Appendix B CEP Opportunities

CEP opportunity 01

Redefine water quality regulations to prioritize use of lower quality non-saline water.

Summary

Source: Non-saline groundwater or surface water
Type: Conservation
Industry: All except oil sands mining

Description

There are non-saline water sources that would be considered by some water users to be lower quality on the basis of water chemistry apart from mineralization (i.e., total dissolved solids). These include environmental uses by some ecosystems, and municipal water supply. Other water chemistry components include elevated concentrations of sulfate, sodium, calcium, chloride, dissolved metals including arsenic and iron, hydrocarbons (both free and dissolved phase), and other organic compounds. Present provincial regulations make no distinction between different types of non-saline waters, as defined solely on the basis of mineralization, and do not accommodate the characterization of water using other components for Water Act applications.

In some cases, this lower quality water would be appropriate for use by the oil and gas sector. Prioritized use of this lower quality non-saline water by the oil and gas sector would help conserve higher quality non-saline sources. The potential benefits include a management structure to allow for more sustainable management of groundwater and surface water resources in the province.

A framework for this style of management has not been developed.

Evaluation criteria, comments

1. Water savings: Low overall savings, but potential for high savings of priority water sources.
2. Net cost: Minor to significant.
3. Cost/Benefit ratio: Low
4. Environmental considerations: Significant. Would allow higher quality non-saline water to remain in the environment.
5. Social impacts: Minor impacts or potential net benefits
6. Linkages with other sectors: Significant. Potential benefits to other users due to improved access to higher quality water.
7. Barriers/constraints: Regulatory
8. Percent participation: Unknown
9. Technology availability: Not a constraint.
10. Implementation timeline: Long-term.
11. Available resources: Yes
12. Risk: Not determined.
13. Sustainability: Potential for significantly improved sustainability of high quality water sources.
14. Stakeholder engagement: Not yet started.

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 02

Reuse municipal wastewater instead of diverting additional water**.**

Summary

Source: Surface water
Type: Efficiency
Industry: Waterflood / Conventional oil / Unconventional gas / Oil sands in situ

Description

The idea to reuse municipal wastewater for industrial purposes is not new, but is not yet common practice. Reusing municipal wastewater would involve a water supply connection to the effluent stream of a wastewater treatment plant, instead of developing a new water source or constructing an additional intake along an existing water source. Although net water savings would be low from this opportunity, this would avoid repeated withdrawal and release activities along a river, assumed to result in a net positive benefit for downstream water chemistry. Some municipalities are targeting this approach to reduce their downstream nutrient loading to rivers and other waterbodies. However, existing water licences may require new conditions to allow the diversion of return flows.

This opportunity may be available near cities where there is a match between supply and demand for water plus convenience of location. Consideration should be given to the benefits of reuse of municipal wastewater compared to the instream benefits of return flows.

Evaluation criteria, comments

1. Water savings: Low.
2. Net cost: Potential cost savings if additional river intake can be avoided, and if wastewater chemistry does not require additional treatment for industrial use.
3. Cost/Benefit ratio: Potential for high environmental benefits for relatively low cost.
4. Environmental considerations: Would allow higher quality non-saline water to remain in the environment.
5. Social impacts: Potential net benefit, due to environmental linkages.
6. Linkages with other sectors: Significant linkage to municipal water supply.
7. Barriers/constraints: Regulatory constraints due to existing water licence conditions that sometimes require high return flows.
8. Percent participation: Likely to be small
9. Technology available: Yes
10. Implementation timeline: No restrictions
11. Available resources: Yes
12. Risk: Low
13. Sustainability: High
14. Stakeholder engagement: n/a

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 03

Consider alternative oil sands tailings technologies and management techniques that are less water-intensive.

Summary

Source: Surface water
Type: Efficiency
Industry: Oil sands mining

Description

Tailings management is closely related to water management in oil sands mining projects. The makeup water requirement for an oil sands mine is largely a function of the amount of water trapped as pore water in the tailings deposit. This water is gradually released and recycled as the tailings consolidate over time. However, the selected tailings dewatering and deposition strategy will affect the overall porewater volume and the availability of that porewater. A variety of tailings technologies are currently being considered, researched and tested to accelerate the settling and consolidation of fines and the release of pore water.

Conventional tailings management at the oldest operating mines produces coarse tailings sand and fine tailings. The coarse portion is the largest portion of solids by about a 4 to 1 margin, and is also the portion with relatively low pore water (about 15% by weight). The remaining portion of fine tailings has relatively high water content (about 65% by weight), and requires a 'water cap' to operate the recycle barge to reclaim water for reuse within the mine site.

Consolidated (or Composite) Tailings (CT) is one of the most commercially ready tailings technologies for future tailings management in oil sands. Most active and planned mines originally committed to this tailings strategy because it was expected to consolidate over time into a material with 80% solids by weight. Therefore, the pore water portion would only be 20%. Oil sands mines have been shifting away from this strategy because it fails to meet the schedule requirements associated with closure reclamation of mine areas (i.e., ERCB Directive 074).

Alternative tailings dewatering and deposition technologies are now being considered or planned for most mines, due in part to landscape reclamation regulations. On the dewatering side these include thickened tailings with about 40%-50% water, and on the deposition side thin lift deposition. The thin lift deposition is a strategy for developing a trafficable surface that can be reclaimed progressively. With thin lifts, water dissipation will be through the mechanisms of evaporation and drainage and possibly freeze/thaw instead of recycling. In many cases, centrifuges are planned to re-process any remnant fine tailings that segregate from the tailings.

In the future, oil sands mines may need to balance the requirement for Athabasca River makeup water and the required schedule for reclaiming the mine areas.

Evaluation criteria, comments

1. Water savings: Potentially very high water savings, or net increase of water use.
2. Net cost: Currently included in the cost of planned mines, but is relatively high cost for mines to change tailings strategy.
3. Cost/Benefit ratio: n/a
4. Environmental considerations: Depends on selected tailings strategy. Accelerated reclamation may be an environmental benefit to be considered.
5. Social impacts: n/a
6. Linkages with other sectors: n/a
7. Barriers/constraints: Some alternative technologies are still in pilot stage;.
8. Percent participation: All oil sands mining companies.
9. Technology availability: CT is a commercialized process. Other technologies are still in pilot testing stage for oil sands but have been utilized commercially in mining for 15 years.
10. Implementation timeline: Within 10 years.
11. Available resources: Yes
12. Risk: There are technical uncertainties, operational unknowns, site specific requirements, and water quality considerations.
13. Sustainability: Potential acceleration of land reclamation and/or reduced Athabasca River water use.
14. Stakeholder engagement: Tailings technologies are a major topic of each regulatory hearing for proposed mines.

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 04

Implement CO_2 injection to enhance recovery instead of injected water

Summary

Source: Non-saline groundwater
Type: Conservation, efficiency
Industry: EOR

Description

The technique of using CO_2 injection to improve recovery of oil reserves or to obtain additional reserves from depleted fields is well documented and is used internationally. In short, CO_2 enhanced oil recovery (EOR) lowers the viscosity of the oil in place and allows more oil to be recovered from the reservoir. This has advantages from an oil and gas water use perspective in that less water is used and the process allows for increased removal of oil from the reservoir. It also has the added benefit of carbon storage; however, this topic is outside the scope of this discussion.

Some oil companies operating in Western Canada have expertise in CO_2injection EOR projects including: Penn West (Pembina, Joffre), Cenovus (Weyburn), Apache (Midale), and others. Alberta also has internationally recognized research expertise in CO_2EOR through Alberta Innovates Technology Futures (formerly the Alberta Research Council) and has industry sponsored organizations that broker technology exchange (i.e., PTAC).

Apart from geological constraints, the primary issues with CO_2EOR are finding an appropriate supply of $CO_2$and having the infrastructure for transporting the $CO_2$to site. There are operators in Alberta that are currently using CO_2 EOR or investigating its use for future projects. Historically these CO_2 projects previously used water-based floods to enhance oil recovery. The change to CO_2EOR, if practical, will result in immediate decreases in water use and increases in efficiency.

This opportunity is most likely to be utilized in southern Alberta where water is relatively scarce but where existing water use by oil and gas is also relatively low.

Evaluation criteria, comments

1. Water savings: Potential high water savings for a project, but likely a small volume on a provincial basis.
2. Net cost: High cost, depending on CO_2 source availability and infrastructure requirements.
3. Cost/Benefit ratio: Variable depending on project specifics, but allows for additional recovery from older fields.
4. Environmental considerations: Valuable environmental benefits with respect to CO_2sequestration and decreased water use.
5. Social impacts: Potential net benefits due to environmental considerations.
6. Linkages with other sectors: May be able to source $CO_2$from other sectors.
7. Barriers/constraints: CO_2availability/supply, available infrastructure.
8. Percent participation: Small.
9. Technology available: Yes
10. Implementation timeline: 1-5 years
11. Available resources: TBD
12. Risk: Not assessed.
13. Sustainability: Depends on life of field and CO_2source.
14. Stakeholder engagement: Usually considered environmentally positive due to reduction of greenhouse gas to the atmosphere.

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 05

Consider alternatives to non-saline water for drilling or frac fluids

Summary

Source: Non-saline groundwater or surface water
Type: Conservation
Industry: Waterflood / Conventional oil / Unconventional gas

Description

Non-saline water is used throughout the life cycle of an oil and gas well (including wells for oil sands in situ operations). For a conventional well, the volume of non-saline water used to drill, complete and abandon the well is generally less than 1,000 m^3. For an unconventional coalbed methane (CBM) well in Alberta, the life cycle use of non-saline water is generally less than 500 m^3 given the shallower well depth and completion method. For unconventional wells in shale gas plays, water use by horizontal wells with several multi-stage fractures can range from 10,000 to 20,000 m^3 per well. Shale gas is not currently being developed in Alberta.

Alternatives to non-saline water are limited given that the water used to drill and install the surface casing may be in contact with shallow non-saline aquifers. In locations where non-saline water is limited, options include the use of municipal wastewater treated to meet the regulatory requirements to avoid impacting shallow groundwater.

After the surface casing is installed, operators have a greater number of alternatives to non-saline water. These alternate sources must be compatible with the surrounding aquifer. Alternative sources include the following:

1. Produced water to be recycled, preferably originating from the same aquifer zone.
2. Saline groundwater or low quality shallow groundwater.
3. Treated wastewater from other water users.

To ensure success, it is essential to identify these alternate sources of water early in the planning stages of the drilling or completion program. For individual projects, significant reductions in non-saline water use could be realized if these opportunities are applied. Multi-well programs are likely the best arrangements for this type of opportunity.

Evaluation criteria, comments

1. Water savings: One hundred to several hundred cubic metres per well.
2. Net cost: minimal if alternate sources are readily available and no treatment is required. If treatment is required, costs could be up to $\$10/m^3$ to treat and deliver alternate sources.
3. Cost/Benefit ratio: n/a
4. Environmental considerations: In the event of a spill, there could potentially be greater environmental impact if a non-saline source is being used.
5. Social impacts: There may be an impact on the income of local farmers who would normally be paid for access to local non-saline water sources.
6. Linkages with other sectors: Potential use of waste water from other industries.
7. Barriers/constraints: Potential regulatory changes may be necessary from ERCB to reuse produced water and from Alberta Environemnt on the use of treated wastewater for drilling and to install surface casing.
8. Percent participation: Unknown. Greater likelihood of implementation from larger member companies who would typically have larger multiple well programs in an area.
9. Technology available: Yes.
10. Implementation timeline: Requires additional planning several months in advance to ensure the water source is compatible with the expected aquifer conditions.
11. Available resources: n/a
12. Risk: Potential for groundwater contamination due to source water uncertainties and uncertain aquifer characteristics.
13. Sustainability: Unknown.
14. Stakeholder engagement: Necessary when using alternate treated sources to install source casing.

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 06

Use saline groundwater for pressure maintenance

Summary

Source: Surface water / Non-saline groundwater
Type: Conservation
Industry: Waterflood / Conventional oil

Description

The use of saline groundwater for pressure maintenance in conventional oil production has been extensively implemented and is growing in use as a source for steam generation for in situ oil sands operations. For new or existing waterfloods, the use of saline groundwater must be assessed locally as an alternative to non-saline surface or groundwater. Further details on the assessment process can be found in Alberta Environment's 2006 Oilfield Injection Policy and corresponding guidance document.

Saline sources must be assessed for yield and compatibility with the formation in which the saline source is being injected. Well logs and the geological survey are good sources of information to assess the presence and potential compatibility issues. If available, the costs of utilizing saline water must be assessed and compared to other sources (e.g., produced water, non-saline water).

Evaluation criteria, comments

1. Water savings: Potential to reduce non-saline water use, primarily for waterflood operations.
2. Net cost: Significantly higher than non-saline groundwater or surface water due to incremental planning costs and infrastructure costs to transport and possibly treat the saline source.
3. Cost/Benefit ratio: Determined on a project-by-project basis
4. Environmental considerations: Net environmental benefits of reduced non-saline water use must be considered alongside potential tradeoffs, such as:
    - Additional land required for pipeline construction,
    - Potentially higher environmental impact from spills or pipeline failures
    - Additional energy required to treat saline water as compared to non-saline
5. Social impacts: n/a
6. Linkages with other sectors: Saline sources would not be used by other sectors
7. Barriers/constraints: Availability of saline water.
8. Percent participation: Already being implemented in dozens of waterflood projects.
9. Technology availability: No limitations.
10. Implementation timeline: < 1 year once source is identified and project economics completed
11. Available resources: Yes.
12. Risk: Not assessed.
13. Sustainability: Yes.
14. Stakeholder engagement: Not required if source being used at an existing facility. For a new facility, consultation related to the waterflood application is required.

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 07

Update equipment and equipment operating procedure for improved water efficiency

Summary

Source: Surface water / Non-saline groundwater
Type: Efficiency
Industry: All

Description

As equipment ages, it may become less efficient and outdated. In some cases, new models are significantly more water efficient. Boilers, cooling systems, gland cooling, and water treatment systems all have the potential to be replaced by more efficient models. There are many sources of information regarding this form of water conservation, and many companies implement water audits to identify the most cost-effective measures. Companies typically implement water efficiency measures with a payback period of two years or less, and will consider measures with a payback period of up to five years.

Examples include:

- Replace single pass pump cooling water systems with closed loop or alternate cooling.
- Consider water cooling system alternatives such as air or glycol cooling systems.
- Optimize or update boiler and water cooling systems to improve blowdown efficiency.
- Update water treatment systems such as reverse osmosis units. Newer units are often 20% or more efficient than older systems by reducing the amount of waste water.

Evaluation criteria, comments

1. Water savings: Varies. Approximately 3 Mm^3/yr reduced water use at Imperial Cold Lake in situ oil sands operations is due to an equipment modernization program.
2. Net cost: Varies.
3. Cost/Benefit ratio: Often less than 5-year payback period.
4. Environmental considerations: Waste stream from water treatment; energy requirement; primary equipment disposal.
5. Social impacts: n/a
6. Linkages with other sectors: Similar applicability to many other commercial and industrial or institutional water users.
7. Barriers/constraints: Process design may pose limitations.
8. Percent participation: Existing older facilities.
9. Technology availability: Yes
10. Implementation timeline: No constraints.
11. Available resources: Yes
12. Risk: Low
13. Sustainability: Yes
14. Stakeholder engagement: n/a

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 08

Reuse oil sands mining wastewater streams for in situ makeup water, such as blowdown from upgraders or tailings pond water.

Summary

Source: Non-saline groundwater
Type: Conservation
Industry: Oil sands in situ and mining operations

Description

Reuse of surplus process water or wastewater at oil sands mines may be possible at some in situ oil sands operations. This is currently being done at Suncor, which pipes cooling water from mining operations to the Firebag in situ facility for steam generation purposes.

This opportunity can be considered if there is surplus water available. Oil sands mines do not store surplus water, so this opportunity may have limited potential. Water chemistry requirements are also an important consideration because water may need to be treated prior to reuse. Feasibility of using tailings pond water for in situ makeup water is currently being investigated.

Evaluation criteria, comments

1. Water savings: No net savings
2. Net cost: Varies. Infrastructure costs may be high.
3. Cost/Benefit ratio: Varies.
4. Environmental considerations: Tradeoffs depend on the availability of other water sources.
5. Social impacts: n/a
6. Linkages with other sectors: No
7. Barriers/constraints: Water availability, water chemistry, infrastructure requirements, treatment sludge disposal.
8. Percent participation: More likely participation near the end of mine life.
9. Technology availability: Yes
10. Implementation timeline: Long-term
11. Available resources: Yes
12. Risk: TBD
13. Sustainability: TBD
14. Stakeholder engagement: TBD

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 09

Use saline water for steam generation at oil sands in situ thermal operations

Summary

Source: Non-saline groundwater
Type: Conservation
Industry: Oil sands in situ

Description

Saline water is defined as water (in this case groundwater) that has a total dissolved solids (TDS) content of greater than 4,000 mg/L. It is typically encountered in the deeper aquifers such as the Clearwater and McMurray formations, although the salinity of the water in these formations is variable. Shallower aquifers such as the Grand Rapids and the Empress tend to be non-saline.

Saline water Is being sourced for make-up water at many SAGD facilities in the oil sands region and currently accounts for approximately half of the make-up water source. As more sites convert to saline water, it is predicted that this number will increase depending on the local availability of saline water.

One of the challenges with saline water sourcing is that it is not locally available at many sites, particularly on the west side of the Athabasca River. Some sites south of Fort McMurray also need to source saline water a considerable distance away, requiring pipelines and associated rights-of-way disturbance footprint. Non-saline water is the preferred source for potable water supply and utility water for SAGD operations.

Evaluation criteria, comments

1. Water savings: High savings of non-saline water, currently implemented at most in situ operations.
2. Net cost: Potential high cost due to off site supply for some projects.
3. Cost/Benefit ratio: Varies
4. Environmental considerations: Minimizes use of non-saline groundwater aquifers or surface water.
5. Social impacts: n/a
6. Linkages with other sectors: No
7. Barriers/constraints: Availability at some sites
8. Percent participation: 50% or more.
9. Technology availability: Yes
10. Implementation timeline: Currently implemented at many operations.
11. Available resources: Yes
12. Risk: Low
13. Sustainability: Depends on available saline water sources.
14. Stakeholder engagement: Yes

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 10

Implement oil sands in situ enhanced recovery by solvent injection

Summary

Source: Non-saline groundwater
Type: Productivity
Industry: Oil sands in situ operations

Description

Adding solvent(s) into or to replace steam in SAGD or Cyclic Steam Stimulation (CSS) is a new oil sands innovation initiative which can potentially increase the recovery of heavy oil or bitumen without consuming more water (as steam). Some examples of these initiatives are Imperial Oil's LASER, Cenovus SAP, Laricina's SC-SADD and Statoil/PTRC's SOLVE.

These recovery technologies combine both heat and solvent(s) into thermal recovery process. Solvents, such as propane, butane or diluents, are injected into the steam to enhance bitumen recovery, while reducing the amount of heat or water required. Some of the pilot tests suggest solvent-assisted SAGD and CSS can reduce operating steam to oil ratios by 30%. As a result, the process may also require less water. In addition, the greenhouse gas emissions associated with the recovery process tend to decrease significantly. The key challenge is to optimize the amount of solvent injected into reservoir and to recover the solvent to make the process economically viable.

Evaluation criteria, comments

1. Water savings: The technologies that supplement water with solvent could reduce steam requirement by 10-50%.
2. Net cost: Depends on solvent recovery.
3. Cost/Benefit ratio: n/a
4. Environmental considerations: Reduced greenhouse gas emissions.
5. Social impacts: n/a
6. Linkages with other sectors: No
7. Barriers/constraints: Uncertain operational feasibility.
8. Percent participation: The technologies could be potentially applied to all thermal in situ projects
9. Technology availability: Limited commercialization, several pilots in place
10. Implementation timeline: Depends on the success of existing pilot facilities.
11. Available resources: Yes
12. Risk: Technology uncertainty; operational difficulty
13. Sustainability: Yes; less energy requirement and greenhouse gas emissions
14. Stakeholder engagement: n/a

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 11

Recycle produced water from oil and gas wells instead of disposal or release

Summary

Source: Surface water
Type: Efficiency
Industry: Waterflood / Conventional oil / Unconventional gas / Oil sands in situ

Description

Water recycling refers to the multiple use of water in a similar process or operation, while water reuse refers to the additional use of water for a different application. Water recycling is already a common practice for a number of operations in the upstream oil and gas sector, including EOR, SAGD, CSS and mining processes. Water is recycled, usually multiple times, until it reaches threshold levels of contamination and must be treated as a waste product. Pursuing water recycling opportunities would reduce overall water diversions by decreasing the overall effluent discharge. Recycling water presents a cost saving opportunity in that the costs for water supply and wastage are reduced.

For the Alberta upstream oil and gas industry, changes to existing ERCB and Alberta Environment requirements would be required to enhance this opportunity. The ERCB currently considers produced water to be a waste and as such it must be safely re-injected into the subsurface either in disposal wells or injectors to maintain reservoir pressure.

Evaluation criteria, comments

1. Water savings: Low or none, assuming produced water is currently disposed to non-saline sources. Water savings may be relatively high if the water would otherwise be disposed to saline water sources.
2. Net cost: May be relatively low, depending on configuration of the facility and duration of water requirements.
3. Cost/Benefit ratio: > 1 B:C ratio where limited produced water is available and non-saline water is costly to source.
4. Environmental considerations: There is little environmental risk associated with the management of produced water.
5. Social impacts: None
6. Linkages with other sectors: n/a
7. Barriers/constraints: Cost, duration of water demand.
8. Percent participation: Unknown.
9. Technology available: Yes
10. Implementation timeline: Immediate where treatment prior to reuse is not required. Generally 2 to 3 years to assess opportunity on an asset level scale.
11. Available resources: Yes. Several producers have direct experience
12. Risk: Low
13. Sustainability: Sustainable if demand for produced water exists.
14. Stakeholder engagement:

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 12

Implement in situ combustion to enhance recovery at oil sands in situ operations

Summary

Source: Non-saline groundwater
Type: Productivity
Industry: Oil sands in situ operations

Description

In situ combustion (also known as fire flooding) involves heating a heavy oil or bitumen reservoir (typically with steam) and subsequently injecting significant quantities of air. This induces an underground fire to melt the heavy oil/bitumen and allow it to flow to collector wells. The heating process causes partial upgrading of the bitumen to a lighter oil that is ready for pipelining and/or direct sales without further upgrading. The process has been successfully used in Romania, India, and around North America. An application of in situ combustion called toe-to-heel air injection (THAI) is being investigated by Petrobank Resources.

This technology is still at the pilot stage in Alberta, and will depend on reservoir characteristics. Two THAI pilot projects are underway: the Whitesands project near Conklin, Alberta; and the Kerrobert project in Saskatchewan. Plans are underway to develop a larger scale THAI project at May River near Conklin.

Advantages of in situ combustion include considerably lower energy needs, water requirements, and greenhouse gas generation, as well as a smaller surface footprint. Water is required for initial steaming only (small amounts are also required for utility water and potable water). Once initial steaming is completed, further injection is comprised of air and not steam. Over a 10 year well life, this will result in significant water savings, as well as reduced energy requirements for steam generation.

Issues being addressed in the current experimental projects include sand in the production wells, heat impacts on the production wells and control of the fire front. Current estimates indicate that the THAI process can recover more bitumen than the SAGD process.

Evaluation criteria, comments

1. Water savings: Significant potential reduction in water requirement at in situ operations that plan to use this method.
2. Net cost: Pilot costs are about $75,000 per flowing barrel.
3. Cost/Benefit ratio: Variable, depending on reservoir characteristics.
4. Environmental considerations: Less water use, greenhouse gases, and surface disturbance.
5. Social impacts: Lower than existing SAGD operations.
6. Linkages with other sectors: Reduced requirement for upgrading.
7. Barriers/constraints: Technology not yet proven for application to the oil sands.
8. Percent participation: One experimental site in the Athabasca oil sands area, one in Saskatchewan. Plans for a third.
9. Technology availability: In-situ combustion proven. THAI still in pilot stages.
10. Implementation timeline: Uncertain
11. Available resources: Unknown
12. Risk: Low
13. Sustainability: Potentially considerable improvement over SAGD, in terms of sustainability of local water resources.
14. Stakeholder engagement: Ongoing

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 13

Consider water treatment for waste/produced/saline water to be reused or released instead of disposal

Summary

Source: Surface water
Type: Efficiency
Industry: Waterflood / Conventional oil / Unconventional gas / Oil sands in situ

Description

Many oil and gas activities result in the disposal of produced water to deep saline aquifers. This disposal removes water from the available water supply for other uses (i.e., essentially lost to the hydrologic cycle), but the disposal of water provides a benefit by avoiding the release of relatively undesirable water to surface water bodies or non-saline aquifers. Treatment and reuse or release of this water would reduce the net loss of water for water supply purposes. Water reuse would be the most desirable use, as it would likely require less treatment compared to releases to the environment.

This opportunity could be considered in areas with high water disposal rates. This opportunity is currently implemented in the US for shale gas. The treatment technology is mature and readily available.

The feasibility of this opportunity depends partly on water treatment costs and requirements to dispose of sludge material (a by-product of water treatment) to a landfill or other suitable location. Regional industrial water treatment plants may improve the economics of water treatment by sharing the cost among producers. However, issues of ownership and availability may factor into the design and construction of a treatment hub and the pipelines associated with it.

Evaluation criteria, comments

1. Water savings: Potentially high savings in terms of net loss of water to the environment
2. Net cost: Assumed to be high, compared to conventional water disposal.
3. Cost/Benefit ratio: Unknown
4. Environmental considerations: Additional disturbance footprint and disposal of highly concentrated sludge from treatment.
5. Social impacts: Uncertain.
6. Linkages with other sectors: Water supply opportunities with forestry, other industries
7. Barriers/constraints: Economics, demand for treated water.
8. Percent participation: Likely to be limited to areas with relatively high water disposal rates.
9. Technology availability: Yes
10. Implementation timeline: Dependent on regulatory requirements.
11. Available resources: Not assessed.
12. Risk: Additional risk of produced water spills
13. Sustainability: Potentially highly valued opportunity for long-term sustainability
14. Stakeholder engagement: TBD

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 14

Convert to oil sands mining extraction methods that are not water-based

Summary

Source: Surface water
Type: Efficiency
Industry: Oil sands mining

Description

Water-based extraction is a well-developed commercial process for recovery of bitumen from oil sands mining. The process involves addition of warm water and a chemical additive (such as caustic) for separation of bitumen from sand in a form that is suitable for further processing to produce a marketable product. The process inherently produces a tailings stream with relatively high porewater requirements. Therefore, oil sands mining currently stores water in the form of porewater as part of the tailings deposit areas.

The advantage of a non-water based process is the reduction of initial porewater storage within the tailings product. This potential savings will need to be considered in conjunction with potential tradeoffs such as higher energy or chemical requirements. Another consideration for the assessment of non-water based processes will need to be the long-term net water balance. Tailings products with little or no initial porewater may eventually accumulate water by high infiltration of precipitation. This infiltration may result in a long-term trend toward porewater volumes that are similar to tailings products derived from water-based extraction. The difference would be in terms of the time frame for accumulating the water.

Various non-water based methods are currently being considered and researched, and are subject to change. These methods are not yet commercially available.

Evaluation criteria, comments

1. Water savings: Significant potential reduction in Athabasca River water withdrawal. Water, in terms of either precipitation or other sources (dewatering wells) would still be required for geotechnical stability of dry tails. Assuming a requirement of 15% water in “dry tailings,” non-water based operation could present approximately 50% reduction of river makeup water.
2. Net cost: Cost and economics are uncertain.
3. Cost/Benefit ratio: Not known.
4. Environmental considerations: Recovery and recycle of extraction aids (solvent, water, other chemicals) from bitumen and from solids, potential leaching from tailings, volatile organic compounds and odors.
5. Social impacts: Uncertain.
6. Linkages with other sectors. None.
7. Barriers/constraints: Typical constraints with a new technology: high cost of entry, long development time, uncertain regulatory requirements. Uncertain performance or impacts on production.
8. Percent participation: Potential for use by future mines after technologies are proven viable. Retro-fit existing mines would likely be extremely costly.
9. Technology availability: Alternate technologies are at basic research stage.
10. Implementation timeline: Greater than 10 years to commercialization.
11. Available resources: Research is ongoing.
12. Risk: High due to technical uncertainty, economic uncertainty, and absence of defined regulatory requirements for alternate processes.
13. Sustainability: Uncertain.
14. Stakeholder engagement: Industry and government aligned on concept of reduced water use, but are currently focused on water recovery from tailings that are derived from water-based extraction methods.

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 15

Reuse produced water from oil and gas wells instead of disposal or release

Summary

Source: Non-saline groundwater
Type: Efficiency
Industry: Waterflood / Unconventional gas / Oil sands in situ

Description

Produced water, or water generated during the production of oil and gas, is already being reused extensively to maintain reservoir pressures as required by the ERCB. The water volumes are tracked and reported to the ERCB. Produced water has been used by some producers as an alternative to non-saline water for well completions but there remains additional opportunity across the industry. The produced water is generally reused with little to no additional treatment.

There is a potential for efficiencies resulting from the sharing of produced water among companies, due to seasonal availability/use. For example, produced water is currently being redistributed among individual producer's asset areas as a means to maintain reservoir pressure. In specific cases one producer may transport excess produced water via pipeline to another producer who needs the water or possibly to another production area that is operated by the producer some distance from the excess source of produced water.

Additional water withdrawal licence conditions may be needed to reuse water instead of returning it to the environment. Currently, there are no criteria for the reuse of produced water and it is likely that individual Alberta Environment approvals would be required for each produced water reuse/recycle project.

Evaluation criteria, comments

1. Water savings: No net savings of water if return flows are considered, but there is a potential reduced withdrawal of new water from the environment.
2. Net cost: Depends on length of pipeline and disposal costs. May be a net savings to producer if costs of disposal are higher than costs to pipeline produced water to its new location.
3. Cost/Benefit ratio: Unknown
4. Environmental considerations: Potential for greater environmental risk due to pipeline leaks as compared to disposing of water at point of generation.
5. Social impacts: None
6. Linkages with other sectors: Minimal.
7. Barriers/constraints: Cost, licence conditions, regulations, and local demand for water reuse.
8. Percent participation: Uncertain. Produced water is currently being reused to replace non-saline water sources during well completions of deep natural gas or to hydraulically fracture shale gas wells.
9. Technology available: Yes
10. Implementation timeline: No constraints
11. Available resources: Yes
12. Risk: Likely to be low
13. Sustainability: Yes, this opportunity would contribute to the overall sustainability of water sources.
14. Stakeholder engagement: TBD

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 16

Use evaporator technology to treat blowdown at oil sands in situ operations

Summary

Source: Non-saline groundwater
Type: Conservation
Industry: Oil sands in situ operations

Description

Oil sands in situ operations, such as Steam-Assisted Gravity Drainage (SAGD) operations, typically have a multi-stage water treatment process using lime softeners and cation exchange to remove inorganic constituents such as silica, calcium and magnesium. The treated water is directed to a once-through steam generator (OTSG) to produce steam from the relatively high total dissolved solids content water that is often used.

Evaporator towers have been used as an alternative to this process since 2000, and are currently being used on over ten SAGD projects. An evaporation system can increase the water recovery from 90% to as high as 98% and can potentially be used in conjunction with a zero liquid discharge (ZLD) system to reduce or potentially eliminate liquid waste streams from a SAGD plant. Since the water quality from an evaporator system is considerably better than the traditional systems, more economical drum boiler systems can be used with the plant. Advantages include lower capital and operating costs, improved steam quality, less boiler blowdown water, less wastewater injection, and potential integration with a ZLD system. An evaporator system requires greater power consumption although this is of an issue for sites that have cogeneration capacity.

The advantages are: reduced make-up water requirements; reduced wastewater production; reduced blowdown; and reduced waste.

Evaluation criteria, comments

1. Water savings: Reduced make-up requirements
2. Net cost: Reported less capital investment and operational costs.
3. Cost/Benefit ratio: n/a
4. Environmental considerations: Reduced water supply and disposal are both net benefits.
5. Social impacts: None
6. Linkages with other sectors: None
7. Barriers/constraints: No technical constraints.
8. Percent participation: About 20% of current installed capacity.
9. Technology availability: Available and in use.
10. Implementation timeline: Not an issue.
11. Available resources: Existing suppliers of technology.
12. Risk: Low
13. Sustainability: Strong contribution to overall sustainability of in situ development.
14. Stakeholder engagement: Yes, as part of approval process.

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 17

Reduce evaporation from ponds

Summary

Source: Surface water
Type: Efficiency
Industry: Oil sands mining

Description

There is a potential opportunity to reduce evaporation losses from tailings ponds at oil sands mining operations. Currently, water losses are due to the following:

- Natural evaporation net of precipitation from the pond surface area.
- Additional evaporation due to relatively high temperature tailings deposits.

Both of these losses are difficult to measure and to confirm. However, they have been estimated for each mine as part of the environmental regulatory and mine water management processes. Evaporation from ponds at oil sands mines accounts for about 20% of the total Athabasca River makeup requirement. This is based on 14 Mm^3 per year or 0.17 m of net evaporation each year (i.e., precipitation minus evaporation) for about 80 km^2 pond surface area (assuming 60% of 130 km^2 footprint for tailings facilities is pond surface area), plus 4 to 8 Mm^3 per year additional evaporation due to high temperature initial tailings deposits.

Technologies to reduce pond evaporation include tailings heat recovery systems to reduce the temperature of initial tailings deposits. The heat would then be recycled to other aspects of the extraction process. Technologies exist for this these types of applications, but design issues may arise for large pipes with high solids content. The benefit/cost incentive would also need to be evaluated on a project-specific basis.

Another option would be to treat or cover the pond surface to reduce evaporation. Some technologies are available, typically for smaller ponds, and often for other purposes such as control of UV penetration to control algae. This option has not been tested in the oil sands, and unintended consequences will need to be considered before implementing such technologies.

Evaluation criteria, comments

1. Water savings: Uncertain. It is unlikely that evaporation could be eliminated, but it may be reduced slightly.
2. Net cost: Unknown.
3. Cost/Benefit ratio: Unknown.
4. Environmental considerations: Successful application would reduce Athabasca River withdrawal by an equivalent amount.
5. Social impacts: None.
6. Linkages with other sectors: None.
7. Barriers/constraints: Technologies are not yet applied at oil sands mines.
8. Percent participation: Potential for all oil sands mines to participate.
9. Technology availability: TBD.
10. Implementation timeline: 5 years.
11. Available resources: Unknown.
12. Risk: Other (environmental) consequences or benefits not yet identified.
13. Sustainability: Potential for reduced water use footprint.
14. Stakeholder engagement: TBD

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 18

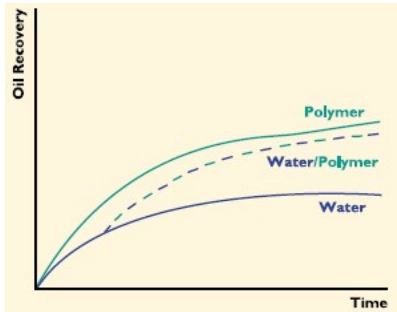
Add polymers to waterfloods for improved productivity

Summary

Source: Surface water / Non-saline groundwater
Type: Productivity
Industry: Waterflood

Description

Polymer floods are an enhanced oil recovery technique in which a polymer solution is pumped into a reservoir through a distributed system of injection wells. The chemical solution reduces the interfacial and capillary forces between oil and water and triggers an increase in oil production. Therefore, this is an opportunity for increased productivity, and not an opportunity for water savings.



The opportunity needs to be assessed on a reservoir-by-reservoir basis as the opportunity is not applicable to all projects. Increased production from the reservoir is required to offset the chemical costs and facility and distribution costs (new injectors may be required). Many chemicals require water that is compatible and in some cases water treatment may be required especially where saline water or produced water is the main source of water for the water flood scheme. These additional water treatment costs may render the opportunity uneconomical.

Evaluation criteria, comments

1. Water savings: None
2. Net cost: Assessed on project-by-project basis. Costs of polymer and facility modifications need to be offset by increase in oil production.
3. Cost/Benefit ratio: Dependent on expected increases in oil recovery.
4. Environmental considerations: None
5. Social impacts: None
6. Linkages with other sectors: None
7. Barriers/constraints: Cost and reservoir suitability.
8. Percent participation: Several in province already in place.
9. Technology available: Yes
10. Implementation timeline: Pilot test generally performed first to assess feasibility.
11. Available resources: Many. Producers have direct experience in several reservoirs across the province.
12. Risk: Potential financial risk if oil recovery does not cover additional costs of implementing the opportunity.
13. Sustainability: This technology contributes to energy resource conservation.
14. Stakeholder engagement: None required unless additional volumes of non-saline water are required.

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 19

Consider storage of water in aquifers for future use

Summary

Source: Non-saline surface water
Type: Efficiency
Industry: Oil sands in situ, conventional oil

Description

Aquifer storage and future recovery of water, also known as ASR (aquifer storage and recovery), is practiced worldwide and is used in areas of seasonal surface water supply shortages. ASR projects have been used to store and recover water for drinking water supplies, irrigation systems, and ecosystem restoration projects. The process involves the artificial recharge of aquifers during wet periods, or periods of water abundance/low demand, and the subsequent recovery of the water when needed. ASR is used as a tool to move towards water supply reliability and sustainability. To be feasible, ASR requires suitable subsurface storage capacity that has not yet been identified and proven in Alberta. ASR background information and summaries are available through the US EPA (1999), CSIRO (2006), NGWA (2010), and the National Academy of Sciences (2008).

The opportunities in the oil and gas sector are primarily two-fold:

- In water-short areas, ASR could be used for EOR projects and / or larger scale drilling and completions to decrease the use of surface water during low flow conditions
- In the oil sands development areas, ASR could be used to decrease the pressure on surface water sources during lower flow periods. ASR was considered as part of a larger OSDG study (Golder Associates, 2009), and was estimated to be of limited potential use for oil sands mining due to availability of relatively small volumes.

Evaluation criteria, comments

1. Water savings: No net total water savings. Savings would be seasonal, during low flow periods.
2. Net cost: n/a
3. Cost/Benefit ratio: Depends on water availability.
4. Environmental considerations: Benefits due to decreased pressure on surface water systems during low flow periods.
5. Social impacts: low
6. Linkages with other sectors: No
7. Barriers/constraints: Geology and hydrogeology, and infrastructure requirements (i.e., location)
8. Percent participation: Unknown
9. Technology availability: Well developed in a number of jurisdictions
10. Implementation timeline: 1-5 years (estimated)
11. Available resources: Yes
12. Risk: Low if appropriate characterization and planning are conducted
13. Sustainability: Potential to be a partial solution for seasonal water shortages.
14. Stakeholder engagement: TBD

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 20

Consider surface water storage options for oil sands mining

Summary

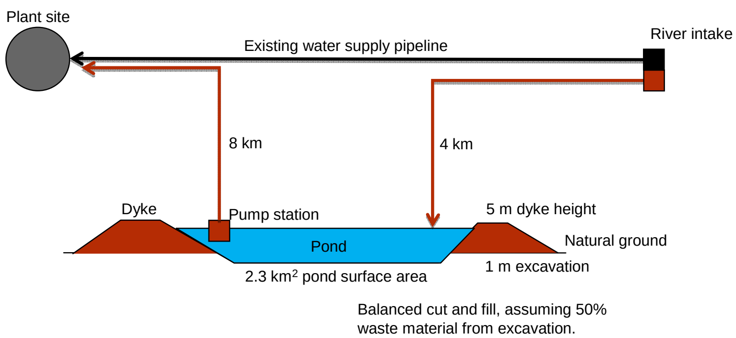
Source: Surface water
Type: Conservation
Industry: Oil sands mining

Description

Surface water storage options for oil sands mining, located either on-site or off-site, have been discussed for several years. The purpose of the storage would be to offset seasonal low flow conditions in the Athabasca River that may result in water shortage conditions – based on the *Athabasca River Water Management Framework* (Alberta Environment & DFO, 2007).

Raw water storage in dedicated ponds is one of the potential engineering mitigation options that were identified and evaluated as part of a previous OSDG study (Golder Associates, 2009). The illustration highlights the infrastructure requirements for this type of opportunity, for a pond with 8 Mm^3 storage capacity. Other forms of surface water storage include additional water in tailings ponds. In either case, water would be withdrawn from the Athabasca River in summer, and used in winter to offset some river withdrawal during low flow conditions.

This option does not reduce the overall water use by oil sands mines. It provides seasonal protection for river ecosystems that may be limited by low winter flows.



Evaluation criteria, comments

1. Water savings: No water savings, but timing of water withdrawal will reduce winter river withdrawal during low flow conditions.
2. Net cost: $ 16/m^3
3. Cost/Benefit ratio: n/a
4. Environmental considerations: Large footprint disturbance area, with.
5. Social impacts: n/a
6. Linkages with other sectors: None
7. Barriers/constraints: Potential limitations on lease space land availability.
8. Percent participation: Potential participation of all oil sands mines except Suncor and Syncrude.
9. Technology availability: Yes
10. Implementation timeline: Subject to mine plan.
11. Available resources: Yes
12. Risk: None
13. Sustainability: Potential to partially mitigate the environmental impact of river withdrawal during natural low river flow conditions.
14. Stakeholder engagement: Phase 2 Lower Athabasca Water Management Framework, Cumulative Environmental Management Association.

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.

CEP opportunity 21

Treat water to increase recycling rate from tailings ponds at oil sands mines

Summary

Source: Surface water
Type: Efficiency
Industry: Oil sands mining

Description

Oil sands mines actively recycle water released from tailings porewater. This recycled water, commonly referred to as process-affected water, typically accounts for more than 80% of the water used in the extraction process. The water is utilized repeatedly for some extraction processes, but is not suitable for some uses such as boiler feed water. Oil sands process-affected water usually has relatively high salinity and contains fines and bitumen residues. Water used for boilers, for example, must be of low salinity, low suspended solids and oil free. Therefore, most mines withdraw water from the river for water supply to boilers and other processes that require cleaner water.

Depending on the water quality requirement of different processes, water treatment could be used to increase the recycle water uses and avoid additional river water withdrawal. The required water treatment processes usually include deionization, de-oiling, and fines reduction. Treatment technologies could include ultra filtration, nano filtration, and/or reverse osmosis.

This opportunity has the potential for only a small reduction of river withdrawal requirements and is relatively costly. Most importantly, oil sands mines currently recycle all available tailings water. There is therefore little or no surplus water available for additional recycle at most mines.

The most likely uses for this opportunity are for relatively small volumes to be handled in special cases, or to avoid storage of ‘blowdown’ water that cannot otherwise be released.

Evaluation criteria, comments

1. Water savings: Small limited potential for water savings.
2. Net cost: $50/m^3$
3. Cost/Benefit ratio: n/a
4. Environmental considerations: Disposal of (sludge) waste stream from treatment process, energy requirements
5. Social impacts: n/a
6. Linkages with other sectors: None
7. Barriers/constraints: Availability of process-affected water, cost
8. Percent participation: Potential for older mines to consider.
9. Technology availability: Yes, but operational testing is still ongoing at the pilot stage.
10. Implementation timeline: one to five years.
11. Available resources: Yes
12. Risk: n/a
13. Sustainability: Contributes to the overall water supply sustainability.
14. Stakeholder engagement: n/a

Note: Evaluation criteria follow the suggested screening criteria provided by the Alberta Water Council.