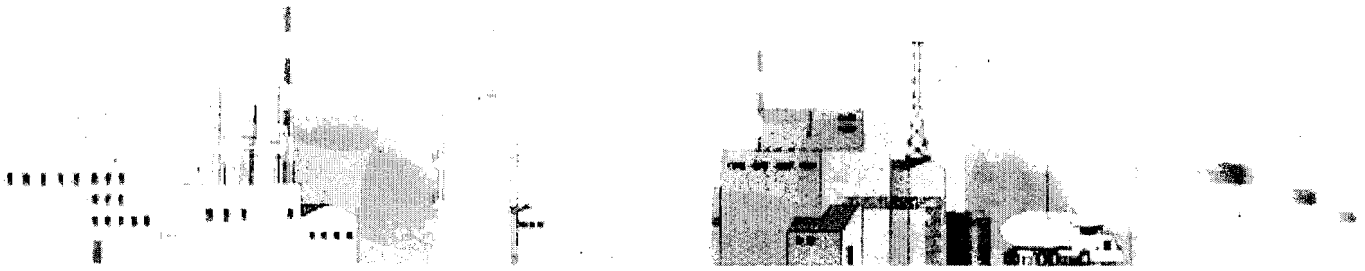

UPGRADING OIL SANDS TO SYNTHETIC CRUDE OIL

Producing the final synthetic crude oil from bitumen requires two stages of upgrading.

The first stage cracks the large bitumen hydrocarbons into smaller molecules. This is done using either coking or hydrocracking or both. In the coking process, excess carbon is removed when high temperatures (circa 500°C) crack the bitumen molecules by vaporizing them. The excess carbon forms a solid residue called coke. The coke, which resembles coal, is then stockpiled as a waste by-product. Hydrocracking involves the addition of hydrogen to bitumen molecules that are cracked using a catalyst, such as platinum.

The second stage of upgrading is called hydrotreating whereby high pressure and temperatures (300-400°C) are used to remove nitrogen and sulphur.

In hydrotreating, metals, sulphur and nitrogen are removed using a catalyst in a hydrogen environment.

The nitrogen is removed as ammonia and is usually used as a source of fuel, while the sulphur by-product is converted to elemental sulphur and either transported for use in other industrial processes (e.g., production of fertilizers) or stored in massive sulphur blocks.

About 65% of the bitumen is upgraded in Alberta to form light, sweet synthetic crude oil.[70] The remainder is transported by pipeline to other regions of Canada and the United States for upgrading.

One barrel of synthetic crude oil produces enough gasoline to fill three-quarters of a Chevy Avalanche's gas tank, or enough to drive it about 490 kilometres.[71]

▲

FIGURE 11
Schematic of oil sands upgrading
SOURCE: CENTRE FOR ENERGY

Bitumen must first be upgraded or transformed into synthetic crude oil before it can be refined.

PHOTO: DAVID DODGE, THE PEMBINA INSTITUTE

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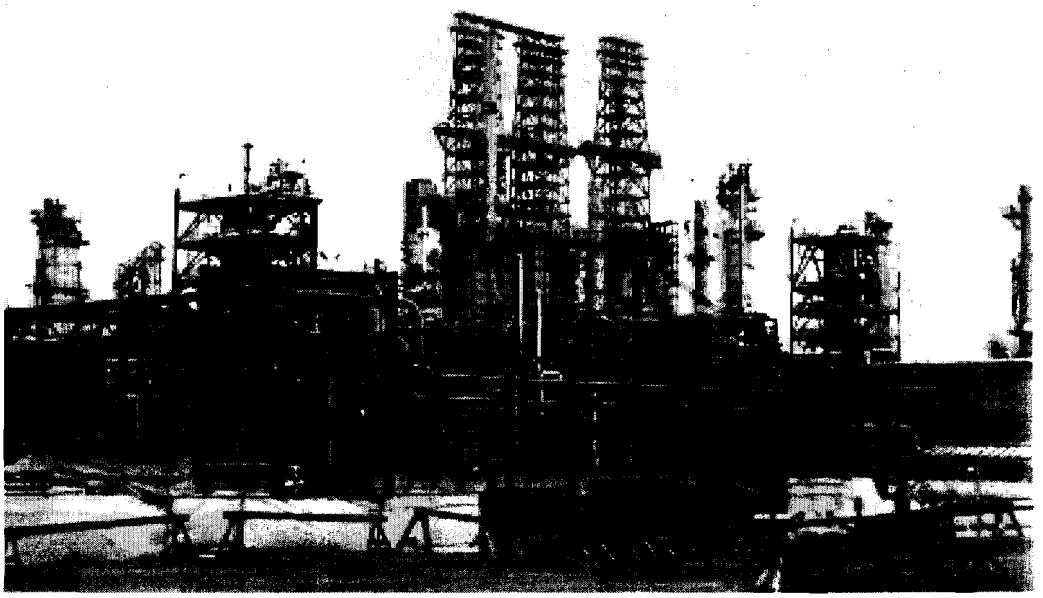


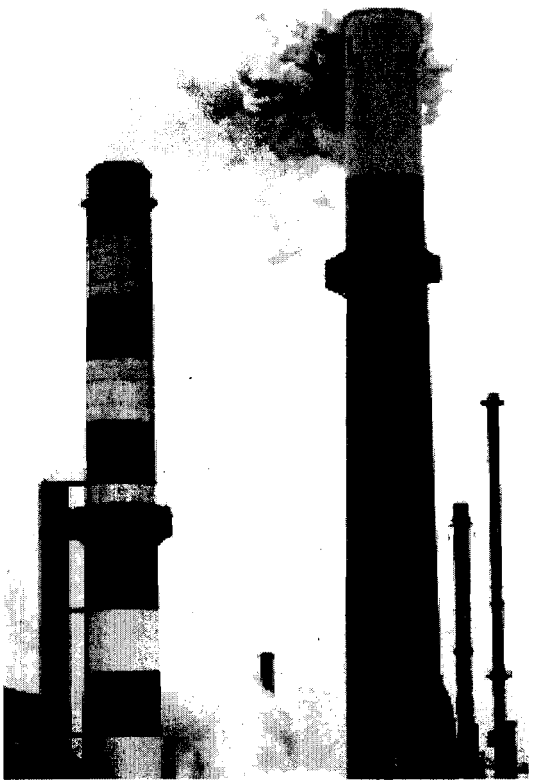
2.2 Fuel for the Oil Sands

Both surface mining and in situ operations are energy intensive endeavours. Natural gas is used both to generate the heat necessary to extract the bitumen from the oil sands and as a source of hydrogen to upgrade the bitumen into synthetic crude oil. Natural gas has traditionally been selected as the fuel of choice because it was relatively clean burning, readily available and (until recently) cheap.[72] Table 2 shows how much natural gas is consumed on a per-barrel basis to produce bitumen and convert it into synthetic crude oil. The oil sands industry consumes about 0.6 billion cubic feet of natural gas per day, enough to heat 3.2 million Canadian homes per day.[73,74]

In 2012, to produce two million barrels per day will require approximately two billion cubic feet of natural gas per day, more than 1.5 times the amount of natural gas that would be available from the proposed Mackenzie Valley Pipeline (Figure 12).[75] This daily requirement is roughly equivalent to the amount of natural gas needed to heat all of the homes in Canada for a day.[76]

"Burning a clean fuel to make a dirty fuel is a form of reverse alchemy, like turning gold into lead. It also leaves less gas for more sensible uses, such as making electricity and heating your home.... When you calculate the toll on gas reserves, the cleanest and most versatile hydrocarbon, the oil sands don't look like a godsend after all."

Eric Reguly, May 28, 2005 The Globe and Mail [78]



▲ *Suncor installed scrubbers in 1996 to reduce SO_2 emissions, achieving a 75% reduction in SO_2 emissions relative to 1990. Regional SO_2 emissions are expected to grow to 295 tonnes per day, which is higher than currently approved emission rates, but lower than the actual emission rates of the early 1990s.* PHOTO: SUNCOR ENERGY

Activity	Volume of Natural Gas Consumed (cubic feet) per Barrel of Bitumen
Surface mining and upgrading	Approximately 750 (250 extraction and 500 upgrading)
In situ production and upgrading	1500 (1000 extraction and 500 upgrading)

▲ *TABLE 2: Natural gas consumption for bitumen and synthetic crude oil production*[77]

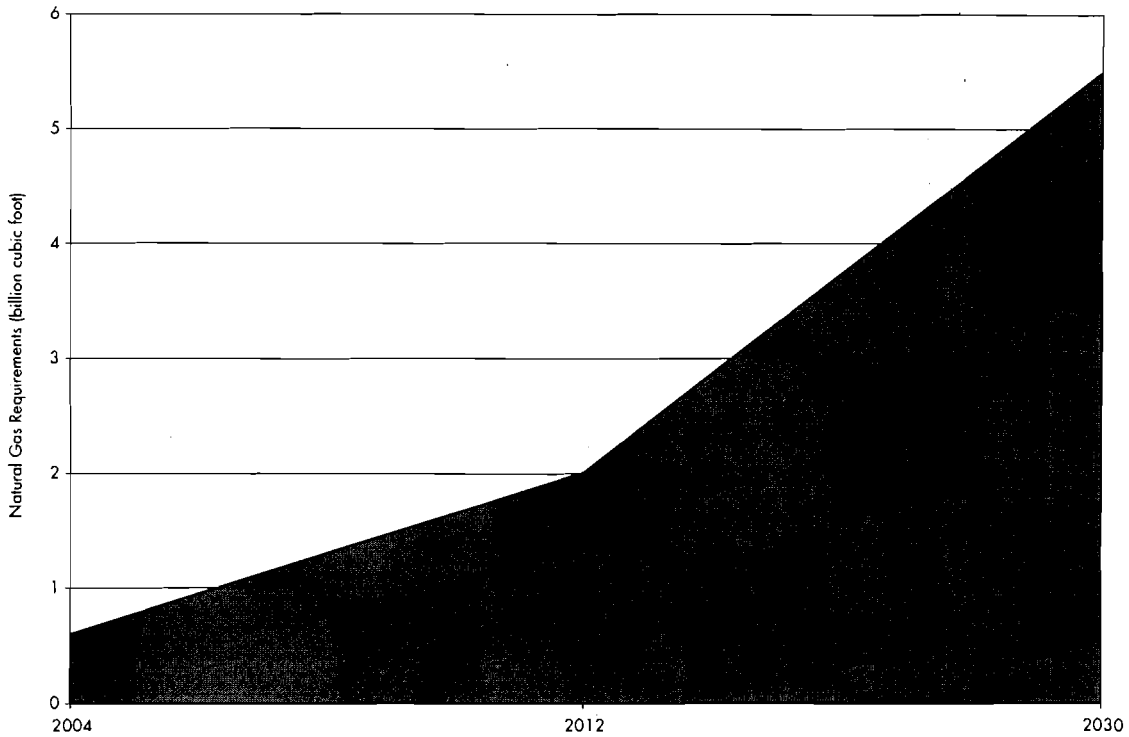


FIGURE 12: Projected natural gas demand for oil sands production 2004–2030 [79]

NUCLEAR ENERGY IN THE OIL SANDS – AN EMERGING DEBATE

With natural gas prices on the rise, oil sands companies have quietly mulled the idea of using nuclear energy to produce synthetic crude oil. This is not the first time that nuclear energy has been considered. In 1958, a collective of oil companies approached the governments of Alberta and Canada with a proposal to detonate a 9-kiloton atomic bomb underground to liquefy bitumen so it could be pumped to the surface.[80] *While the proposal was considered a number of times, it was never implemented.*

In 2003, the Canadian Energy Research Institute concluded that advanced CANDU reactors could be economically viable in the oil sands.[81] *In September 2005, Total SA, who has a stake in the Surmont in situ project and is in the process of acquiring Deer Creek Energy Limited, publicly opened the debate by announcing that it was considering the construction of a nuclear facility in the oil sands region between 2020 and 2025.*[82]

Alberta's premier, Ralph Klein, has reportedly dismissed the idea because of concerns with nuclear waste disposal. But he also noted that he was firmly against using natural gas because it represents "a tremendous waste of a resource."[83] *The Canadian environmental community has long advocated against the use of nuclear power in Canada because of environmental risks, hazardous waste issues and poor economic performance. Many stakeholders would likely oppose proposals for the use of nuclear energy in the oil sands.*

The oil sands industry is coming under fire for its ever-increasing demand for high quality, clean-burning natural gas. Moreover, the purchase of natural gas is a major cost for mining and in situ operations (15% and 60% of the total operating costs respectively), and projections of rising natural gas prices have prompted oil sands producers to actively seek alternative sources of energy.[84,85]

At the present time, gasification of coal or oil sands residue (i.e., the coke by-product of upgrading) appears to be the most likely alternative source of energy to fuel the oil sands.[86,87] However, unless mitigating technologies are also employed, the alternatives to natural gas pose an even greater environmental and climate threat.

2.3 Transportation to Refineries

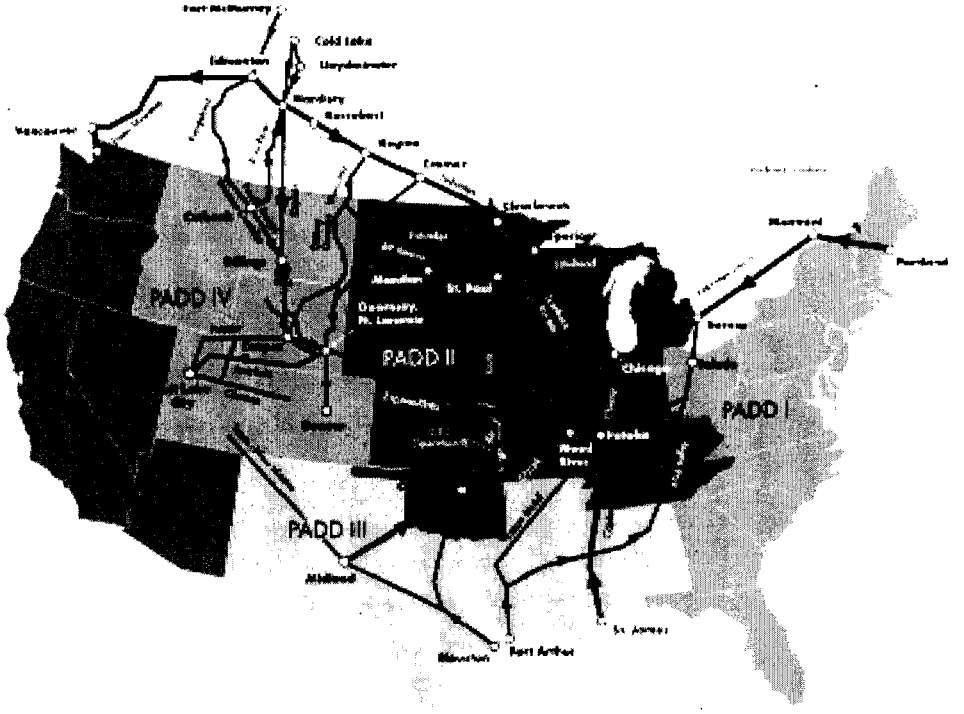


FIGURE 13: Major Canadian and U.S. crude oil pipelines and markets.

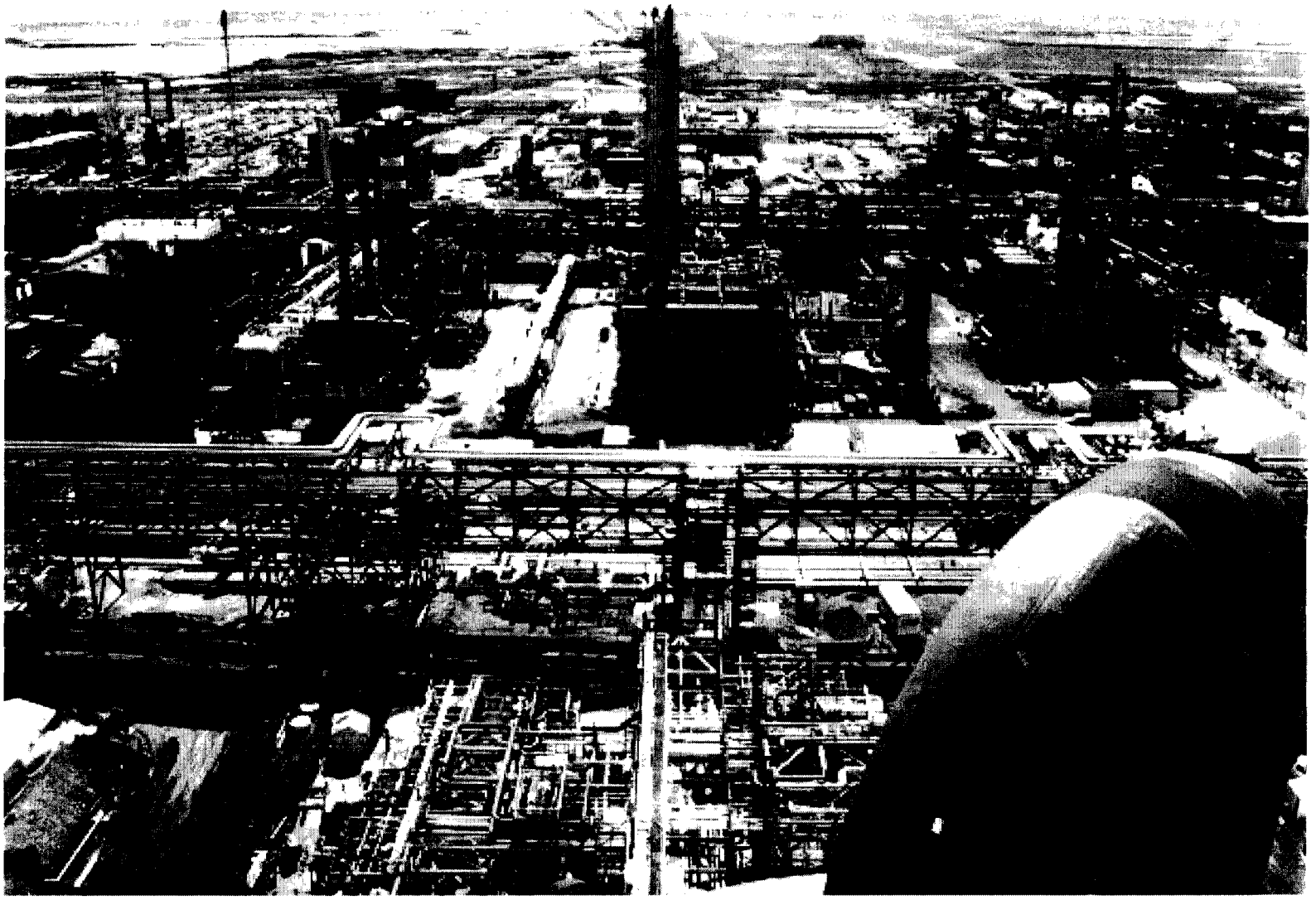
SOURCE: NATIONAL ENERGY BOARD

Moving synthetic crude oil and bitumen from the oil sands producers to refineries is accomplished through a network of pipelines that run from Fort McMurray to Edmonton and Hardisty. While some refining occurs in the Edmonton region, most of the oil sands product is pipelined to Ontario, the Midwest and Rocky Mountain regions of the United States, or to British Columbia and Washington.[88,89] (Figure 13)

There are several new proposals to expand the pipeline capacity between Fort McMurray and Edmonton, and from Edmonton to both eastern Canada and to the West Coast for export to California and Asia-Pacific markets, chiefly China.[90] Enbridge is proposing a new pipeline, the Gateway Pipeline, from Edmonton to a new, deep-water marine terminal in Kitimaat, British Columbia, from where synthetic crude oil will be exported to China, other Asia-Pacific markets and California.[91]

In addition to a proposal to expand the capacity of its TransMountain pipeline, Terasen is considering a pipeline to Kitimaat to compete with Enbridge's Gateway pipeline.[92] Construction of these terminals and their use by oil tankers would require a lifting of the moratorium on tanker traffic along the Pacific coast. These proposals have already encountered significant public opposition.

Once transported to Canadian and American refineries, synthetic crude oil is converted into a wide variety of petroleum products. From a barrel of oil, approximately 72% (by volume) is refined into transportation fuels (40% to gasoline, 25% to diesel fuel, 7% to jet fuel). From the refineries, these fuels are transported by tanker trucks to local gas stations.

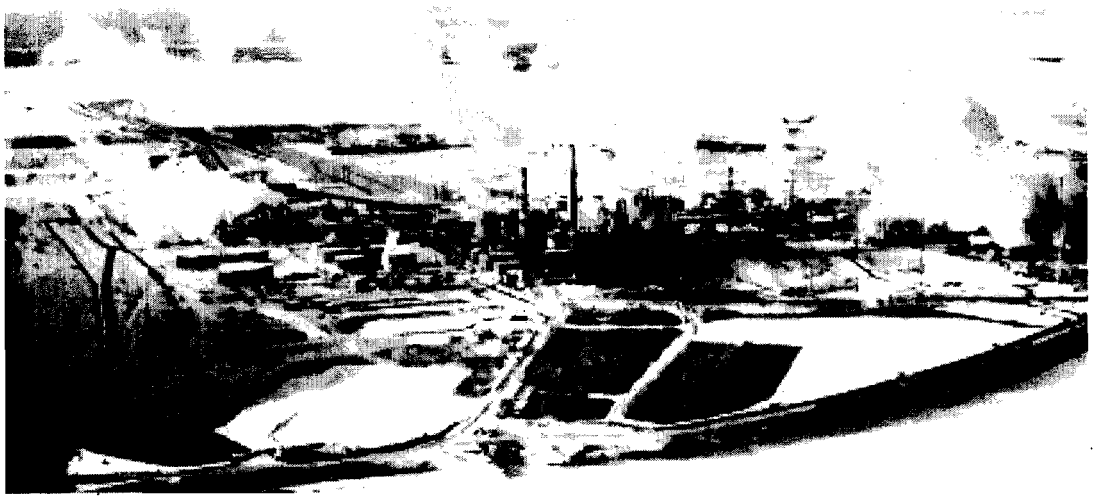


▲ *The upgrading plants are massive complexes that take years to build.*

PHOTO: MELINA MARA. © 2005, THE WASHINGTON POST. REPRINTED WITH PERMISSION

3 Climate Change Consequences

3.1 Escalating Greenhouse Gas Emissions



▲ *The oil sands are the single largest contributor to GHG emissions growth in Canada.*
PHOTO: DAN WOYNILLOWICZ, THE PEMBINA INSTITUTE

The science of climate change leaves little doubt that deep reductions in global greenhouse gas emissions (GHG) must be achieved if we are to prevent drastic worldwide impacts from climate change. These reductions will need to go far beyond the requirements of the Kyoto Protocol: industrialized countries such as Canada need to reduce their GHG emissions to 80%-90% below the 1990 level by 2050.[93]

The oil sands are the single largest contributor to GHG emissions growth in Canada. While the emissions intensity of producing oil sands has decreased substantially, i.e., 26% over the past decade, the rapid rate of new development has more than consumed these gains.[94]

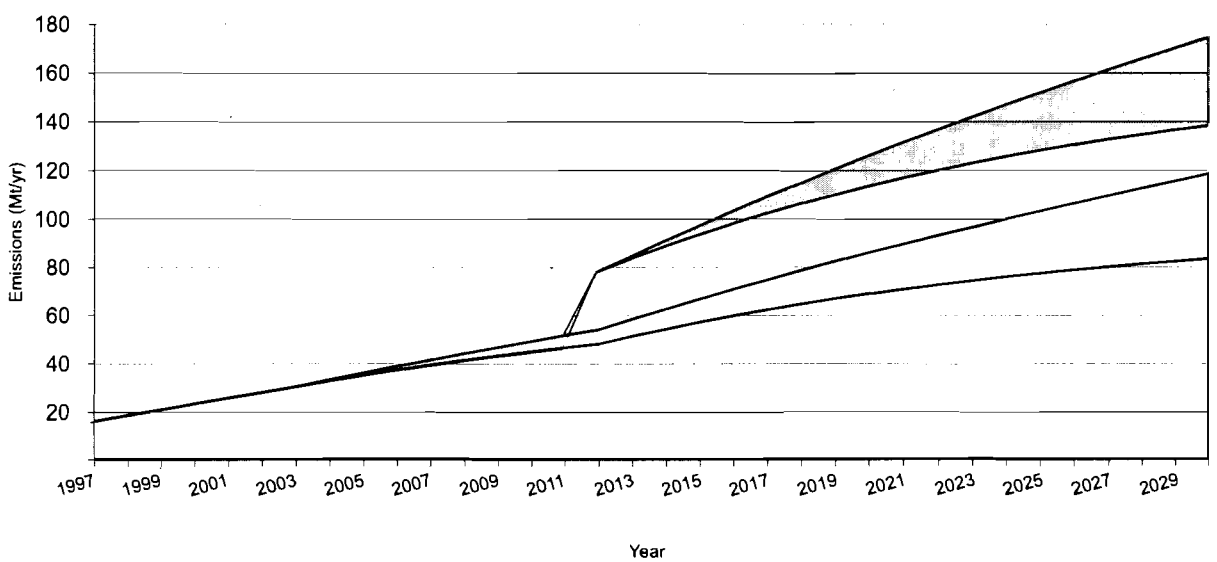
In 1997, the upstream fossil fuel producing industry (activities encompassing the extraction, production and transportation of raw oil, natural gas and coal) accounted for 98 megatonnes (Mt) of GHG emissions, of which 16% (16 Mt) was emitted from oil sands operations.[95] The most recent estimate of GHG emissions for the entire oil sands industry is for the year 2000, when the industry emitted 23.3 Mt, or 3% of Canada's total GHG emissions.[96] To project future GHG emissions

growth from the industry, we have created four scenarios (Table 3). As shown by Table 3 and Figure 14, even the best-case scenario (Scenario 1) will lead to significant growth in GHG emissions.

If oil sands development is not curtailed or more aggressively managed, Canada will have to shoulder its responsibility in the global effort to reduce emissions by requiring the industry to implement technologies that cut the emissions intensity of production, or to offset GHG emissions by investing in emission reductions elsewhere.

[illegible]	[illegible]	[illegible]	[illegible]
Scenario 1 – natural gas	2.3%	57	83
Scenario 2 – natural gas	1%	66	118
Scenario 3 – oil sands residue (e.g., coke)	2.3%	94	138
Scenario 4 – oil sands residue (e.g., coke)	1%	97	175

▲ *TABLE 3: Scenarios for GHG emissions from oil sands in 2015 and 2030*[97]



▲ *FIGURE 14: GHG emission projections for anticipated oil sands production to 2030*

OIL SANDS AND CANADA'S EVER-INCREASING "KYOTO GAP"

The federal government regularly produces projections of Canada's future GHG emissions under a so-called business-as-usual scenario in which governments implement no policies or measures to reduce emissions. The difference between projected business-as-usual emissions in 2010 (the middle year of the five-year period to which the Kyoto target applies) and the Kyoto target is commonly referred to as the Kyoto gap. The Kyoto gap measures the amount by which annual emissions must be reduced below the business-as-usual level to reach the Kyoto target. The federal government has repeatedly increased its estimate of Canada's Kyoto gap, to a significant degree because of increased projections of oil sands production:

The emissions projection produced by the federal government in April 1997 showed a Kyoto gap of 138 Mt.[98]

In October 1998, the Kyoto gap was updated to 185 Mt, with 45% (21Mt) of the increase attributed to new projections for oil sands production.[99]

In December 1999, a further update resulted in a Kyoto gap of 199 Mt.[100]

In February 2002, the Kyoto gap was further revised to 238 Mt, with 18 Mt of the new increase attributed to an additional rise in projected oil sands production.[101]

In April 2005, the government stated that the Kyoto gap is "likely in the area of 270 Mt."[102] *It is widely understood that yet more increases in future oil sands production were, once again, a key factor in this latest increase to the gap.*[103]

It should be noted that the details of why the business-as-usual scenarios needed revision in February 2002 and April 2005 have never been published.

3.2 A Matter of Emissions Intensity

Canada is one of the most energy-intensive countries in the industrialized world. Our energy intensity has declined over the past two decades, but it still remains high because of our energy-intensive industries. Much of Canada's energy production and consumption is fossil fuel based; therefore, the economy's GHG intensity – commonly referred to as carbon intensity – is similarly high. Canada's emissions of GHGs relative to GDP are 25% higher than for the industrialized world as a whole.[104] According to Environment Canada, this high carbon intensity relative to other OECD countries is the result of increased consumption of fossil fuel for electricity generation, increased energy consumption in the transportation sector and growth in fossil fuel production for export.[105]

While Canada's obligation to reduce GHG emissions requires efforts to reduce the carbon intensity of our economy, significant growth in oil sands development will produce the exact opposite. Production of synthetic crude oil from the oil sands is a more GHG intensive endeavor than producing conventional light or medium crude oil.

"Living up to Canada's commitment to Kyoto and at the same time ensuring continued growth together with transition to a less emission-intensive economy is the biggest single economic and political challenge for Canadian energy policy in the coming years. Curbing GHG emissions is all the more challenging as Canada's emissions are growing along with its production and exports of energy which consume large quantities of fossil fuels."

International Energy Agency, January 2005[106]

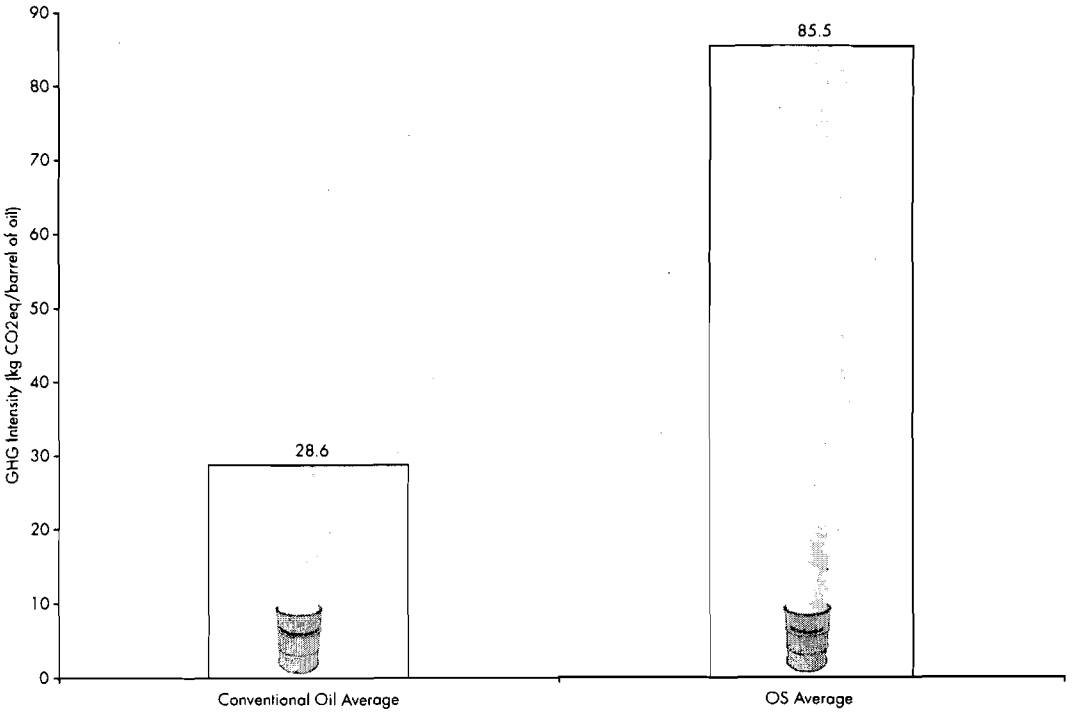


FIGURE 15: Average GHG intensity for conventional oil production versus oil sands synthetic crude oil[107]

As seen in Figure 15, the GHG intensity of synthetic crude oil production from the oil sands is significantly higher than the average intensity to produce conventional oil in Canada. Therefore, as increasing production of synthetic crude oil from the oil sands offsets the decline of conventional oil, the net GHG emissions from the oil industry are set to rise dramatically. While there are a variety of end-of-pipe solutions in the oil sands under evaluation, such as carbon capture and storage, and alternative energy sources, such as deep geothermal, they are years, if not decades, away from full-scale implementation.

3.3 Canada's Climate Contradiction

In December 2002, the federal government ratified the Kyoto Protocol legally binding Canada to reduce its GHG emissions to 6% below the 1990 level between 2008 and 2012. Despite this obligation, Canada's energy strategy remains focused on accelerating growth in oil sands production, the most GHG-intensive form of oil production. This stark contradiction in policy clearly demonstrates the need for Canada to more closely align its energy strategy with its climate obligations.

In April 2005, the government replaced its 2002 *Climate Change Plan for Canada* with a new plan: *Moving Forward on Climate Change – A Plan for Honouring Our Kyoto Commitment.* This new plan lays out the necessary steps for Canada to

OIL SANDS AND THE CLIMATE CONTRADICTION

"We must ensure that there is nothing, as we move forward to implement Kyoto, that in any way undermines or impedes the growth of projects like the oil sands and obviously their contribution to the prosperity of this country."

Deputy Prime Minister Anne McLellan, 2002[108]

"Canada's position on GHG emissions reduction is ambivalent. It can be described as someone trying to ride two horses galloping in opposite directions. One horse pulls energy investments towards the fossil fuels sector, thus increasing GHG emissions. The opposite horse pulls programmes and policies aimed at reducing GHG emissions."

Charles Caccia, former Chair, House of Commons Standing Committee on Environment and Sustainable Development, 2002[109]

▲ *Growing GHG emissions from the oil sands threaten Canada's ability to meet its Kyoto obligation and diminish its international reputation.* PHOTO: DAVID DODGE, THE PEMBINA INSTITUTE

achieve a 270 Mt reduction in annual GHG emissions by 2010. An essential component of this plan is a Large Final Emitters (LFE) system of mandatory emissions targets and trading to secure GHG emission reductions by heavy industry, including the oil sands sector. Large Final Emitters are responsible for nearly 50% of Canada's GHG emissions.

However, industry lobbying has led to government plans to require only 36 Mt of reductions from Large Final Emitters during 2008-2012. So although responsible for nearly 50% of Canada's GHG emissions, they will only be required to achieve 13% of the 270 Mt reduction target. Targets for new facilities in the LFE system are to be set at the level of "best available technology

Project	Kyoto compliance cost (US$/barrel)
Canadian Natural Resources Ltd. Horizon Mine & Upgrader	$0.18
OPTI/Nexen Long Lake SAGD	$0.34
Petro-Canada Mackay River SAGD	$0.12
Syncrude Mines & Upgrader	$0.24
Suncor Mines, SAGD & Upgrader	$0.24
Albian Sands Athabasca Oil Sands Project	$0.15
*Assumes $15/tonne and 85% free permit allocation	

▲ *TABLE 4: Predicted Kyoto compliance costs for oil sands operators*[110]

economically achievable" (BATEA). If the government accepts oil industry arguments that its current technology is already BATEA, then new oil sands facilities could be exempted from any meaningful contribution at all to Canada's Kyoto effort. The government has estimated, and industry has confirmed, that these targets represent a worst-case cost of no more than 25 cents a barrel to the oil industry (Table 4). Given that oil prices are likely to remain above US$50 per barrel, this is an economically insignificant and inadequate contribution to Canada's Kyoto effort.

Certain companies have acknowledged the need to take action to reduce their GHG emissions thereby demonstrating an ability and willingness to go further than what is likely to be required of them by the federal government. For example, after receiving approval for its Athabasca Oil Sands Project (AOSP), Shell Canada committed to achieving a 50% reduction in GHG emissions relative to its projected emissions intensity of 65 kilograms of GHGs per barrel of bitumen. The company plans to do this through a combination of reduced energy consumption, improved energy efficiency, the purchase of domestic offsets and feasibility studies regarding $C0_2$ capture.[111] This example clearly demonstrates that the industry can go well beyond what the federal government expects of it.

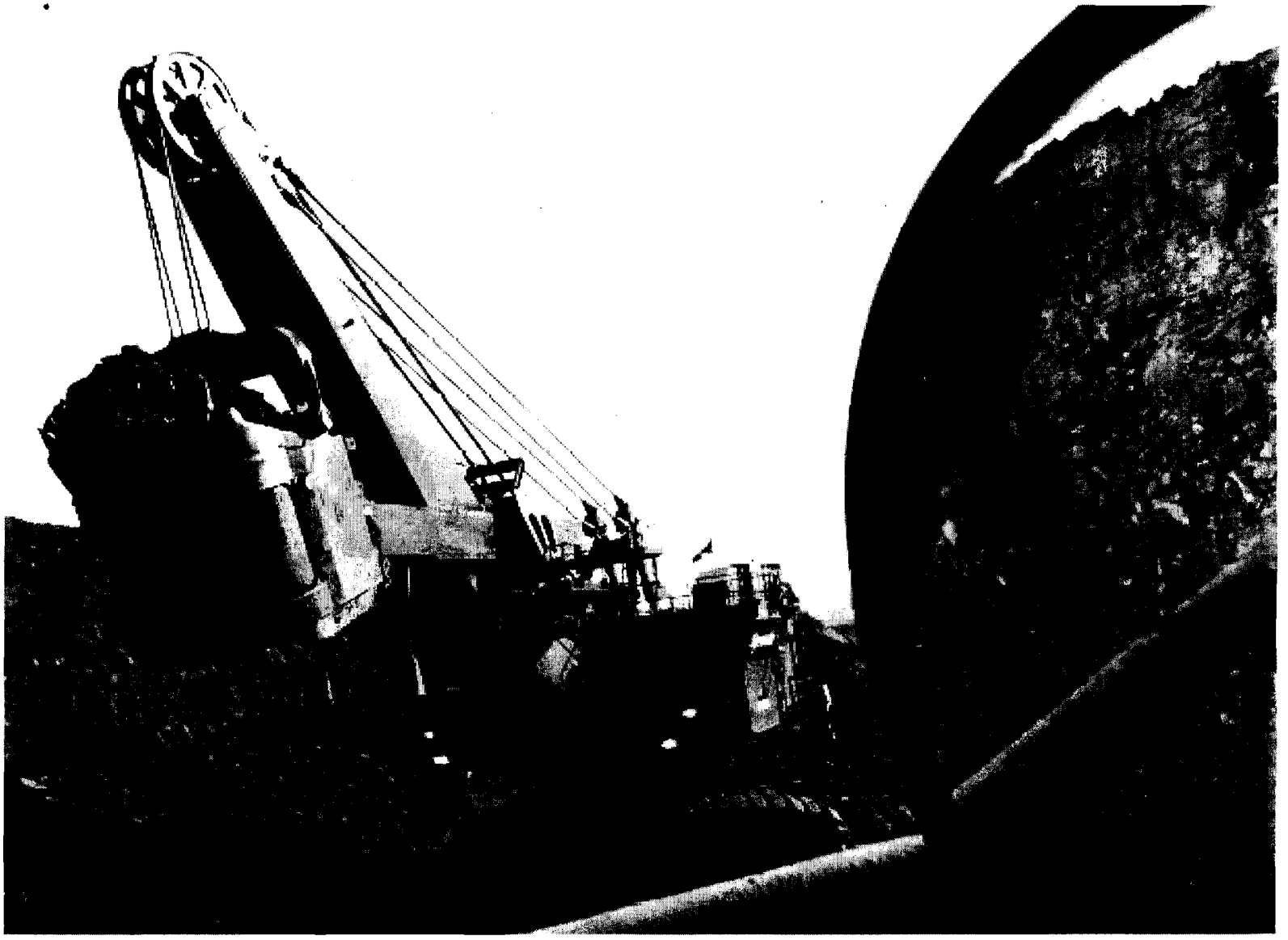
3.4 Taking Meaningful Action

Both government and business leaders widely recognize climate change as one of the greatest and most pressing challenges of the 21st century.[112]

To effectively tackle this challenge will require strong leadership and action in both the short and long term on the part of government and the oil sands industry.

"The scientific understanding of climate change is now sufficiently clear to justify nations taking prompt action. It is vital that all nations identify cost-effective steps that they can take now, to contribute to substantial and long-term reduction in net global greenhouse gas emissions."

Statement by the National Science Academies of all G8 countries, China, India and Brazil. June 2005[113]



▲ *Only about 10% of the tar sands are actually oil. Therefore, vast quantities have to be mined to produce one barrel of oil.*

PHOTO: MELINA MARA. © 2005, THE WASHINGTON POST. REPRINTED WITH PERMISSION

4 Environmental Impacts

4.1 Cumulative Environmental Impacts

The expression "death by a thousand cuts" is often used to describe the accumulation of environmental impacts resulting from multiple industrial activities. Technically referred to as "cumulative environmental impacts," the accumulation of impacts may appear insignificant on their own but can lead to significant and often irreversible ecological damage. In few places is this concept more tangible than in the Athabasca oil sands region, where a proliferation of in situ and surface mining operations are rapidly degrading the regional environment.

The boreal forest ecosystem is resilient, but it can only withstand so much degradation before its ability to recover is exceeded. This proverbial "tipping point," referred to as an ecological threshold or environmental limit, represents the extent of change that an ecosystem can endure before this change is irreversible. As the industrialization of the northeast quadrant of Alberta continues unabated through oil sands development, forestry, and conventional oil and gas, threats to the region's long-term ecological sustainability escalate.

We need to ensure we have the scientific information to understand how the boreal ecosystem – its air, land and water – will react to the impacts of development. It would then be possible to determine, for example, how much water can be removed from the Athabasca River before fish populations are affected, how much habitat can be destroyed before wildlife species are lost and how much air quality can change before the ecosystem is irreversibly stressed.

The following sections describe how the oil sands industry impacts the region's water, land and air and provide projections of the even greater impacts that will accompany planned development to approximately 3.7 million barrels per day of oil sands production.[114] If production reaches five million barrels per day (or higher) by 2030, the environmental impacts will be even greater than those described below.

"There is no environmental minister on earth who can stop the oil from coming out of the sand, because the money is too big. But we have to be very strict on environmental impact."

Stéphane Dion, Federal Minister of Environment[115]

CUMULATIVE SOCIO-ECONOMIC IMPACTS

As the hub of regional oil sands development, the Regional Municipality of Wood Buffalo (RMWB) is growing rapidly and changing. First Nations and Métis people make up approximately 6% of the RMWB's population, the vast majority of whom live in small communities outside Fort McMurray.[116,117] The RMWB is struggling with the socioeconomic impacts such as lack of affordable housing and insufficient infrastructure e.g., roads and schools. The regional First Nations and Métis face similar challenges as they seek to balance the benefits of job creation and a booming economy with ensuring that their culture, the region's environment and their traditional way of life are preserved. Not unlike cumulative environmental impacts, the rush of development is having cumulative socioeconomic impacts. While beyond the scope of this report, managing these socioeconomic impacts is also an urgent issue.

4.2 Troubled Waters

▲

Oil sands operators rely on large amounts of fresh water to extract the bitumen from the oil sands.

PHOTO: DAVID DODGE, THE PEMBINA INSTITUTE

The scale and growth of surface mining and in situ development pose water use and management challenges that will need to be overcome to prevent significant environmental impacts. The predominant technologies for extracting bitumen from the oil sands all rely on large amounts of fresh water, which is withdrawn from both groundwater and surface water bodies (rivers and lakes).

Oil sands mining operations impact water resources in a number of ways, both directly and indirectly, as a result of muskeg and overburden drainage, aquifer dewatering, withdrawal of water from the Athabasca River and the long-term management of tailings. The Alberta Chamber of Resources has identified water use as one of the top four challenges for oil sands mining operations.[118]

Similarly, in situ operations can impact the quantity and quality of both groundwater and surface water bodies (including wetlands). From lowering the levels of groundwater aquifers to the production of large volumes of waste associated with water treatment, in situ operations pose a number of risks to water resources.

4.2.1 The Athabasca River

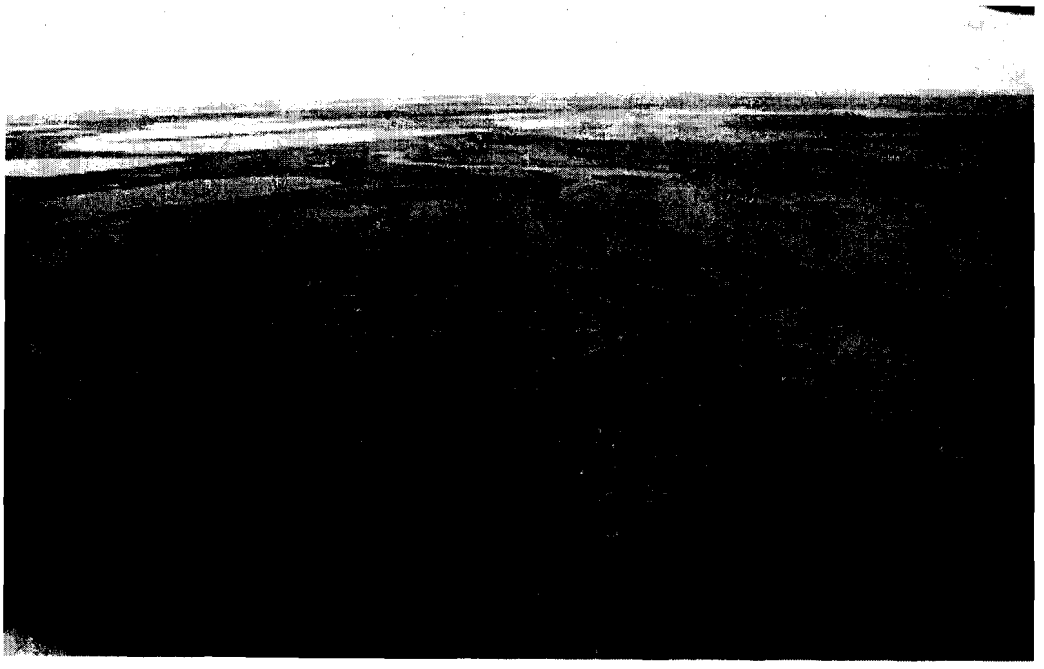
The Athabasca River is the longest river in Alberta, winding 1,538 kilometres from its source, the Athabasca Glacier in Jasper National Park, to Lake Athabasca in Wood Buffalo National Park. It enters Lake Athabasca at the Peace-Athabasca Delta, the largest boreal delta in the world, and one of the most important waterfowl nesting and staging areas in North America.[119]

Oil sands surface mining operations upstream of the delta have been listed as one of the threats to its integrity because large amounts of water are withdrawn from the Athabasca River for use in the extraction process.[120] Between two to five barrels of water are withdrawn from the Athabasca River for each barrel of bitumen extracted. Less than 10% of the water approved for withdrawal is returned to the river.[121] The Athabasca River's ecosystem requires adequate flows and natural seasonal variations to support healthy fish populations. This relationship is referred to as the river's instream flow needs and is the amount of water the river needs to sustain a healthy environment. The Athabasca River has less water flowing during the winter months, so habitat for the many fish species e.g., northern pike, walleye and burbot that spend the winter in the Athabasca River is limited. Therefore, further reductions in flow because of water withdrawals could reduce the amount of habitat available for fish.

▲

Oil sands companies are currently licensed to divert a total of 349 million cubic metres of water from the Athabasca River, enough to satisfy the needs of a city of two million people.

PHOTO: DAVID DODGE, THE PEMBINA INSTITUTE



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The Athabasca River flows into the Peace-Athabasca Delta, the largest boreal delta in the world, and one of the most important waterfowl nesting and staging areas in North America.

PHOTO: DAVID DODGE, THE PEMBINA INSTITUTE

After five years of gathering information, Alberta Environment plans to identify how much water must remain in the river to provide adequate habitat for the fish. Then the department can make informed decisions about how much water can be withdrawn during the winter while ensuring that the ecosystem is fully protected. However, considering the industry's assertion that alternatives to water-based extraction technology will likely not emerge for 20 years,[123] it is also critical for industry and government to manage the timing and development of future projects (whether singly or as a region) to ensure that the Athabasca River is protected.

"The tailings ponds in Canada would not be legal in the United States under our environmental laws."

Tom Bachtell, Wind River Resources Corp[122]

4.2.2 A Tailings Legacy

Water used for extraction at oil sands mines ends up in tailings – a slurry of bitumen, water, sand, silt and fine clay particles – that is pumped to tailings ponds. While commonly referred to as ponds, these enormous bodies of water and the dykes that contain them are some of the largest human-made structures in the world. Collectively, they cover an area of land greater than 50 square kilometers.[124]

In these ponds, the sand, silt and fine clays slowly settle to the bottom. Then as much water as possible is pumped back to the extraction plant and reused in the extraction process. Because of the bitumen that remains in the tailings, the ponds pose a number of environmental risks including the migration of pollutants into the groundwater system and leakage into the surrounding soil and surface water.[125]

One such group of pollutants are the naphthenic acids that are a naturally occurring family of compounds found in bitumen. During the bitumen

Tailings ponds already cover an area of land greater than 50 square kilometers.

PHOTO: CHRIS EVANS, THE PEMBINA INSTITUTE

TAILINGS PONDS

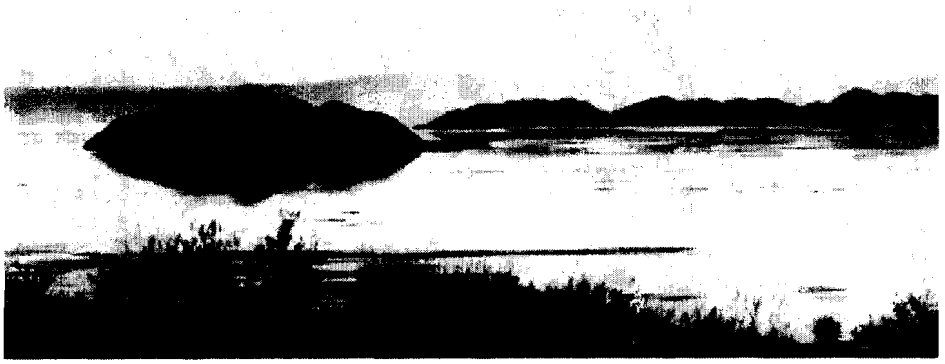
Approximately six cubic metres of tailings are created for every cubic metre of bitumen produced. The tailings are comprised of 3-5 cubic metres of water and approximately 1.5 cubic metres of fluid fine tailings.[126,127,128]

Syncrude's Southwest Sand Storage (SWSS) Facility is one of the three largest dams in the world.[129]

Existing tailings ponds can be seen from space.

Syncrude's Mildred Lake tailings pond contains more than 400 million m³ of tailings, enough to fill 160,000 Olympic-sized swimming pools.[130,131]

Suncor's mining operations include nine tailings ponds that cover an area of 2,280 hectares.[132]



▲ *Tailings ponds pose a number of environmental risks including the migration of pollutants into the groundwater system and the leakage into the surrounding soil and surface water.*

PHOTO: DAN WOYNILLOWICZ, THE PEMBINA INSTITUTE

extraction process, these acids become concentrated and end up in the tailings ponds. The concentration of naturally occurring naphthenic acids in rivers in the region is generally below 1 milligram per litre (mg/ L) but may be as high as 110 mg/L in tailings ponds.[133]

The water in tailings ponds is also acutely toxic to aquatic life.[134] Although recent studies indicate that acute toxicity in wild mammals is unlikely under worst-case exposure conditions, repeated exposure may have adverse health effects.[135] In addition, the presence of the bitumen in the tailings ponds means that migratory birds that might be tempted to land must be scared away by propane cannons (a noise deterrent) and floating scarecrows.

The ultimate objective is to wait for the fine clay particles to settle in the tailings and become what is known as fluid fine tailings. This can take anywhere from a few decades to 150 years depending on the technology employed.[136] These fluid fine tailings pose a reclamation challenge because they are simply too wet and toxic to incorporate into a reclaimed landscape. The National Energy Board characterizes the problem of managing fluid fine tailings as "daunting" – the volume of fluid fine tailings produced by Suncor and Syncrude alone will exceed one billion cubic metres by the year 2020, enough to fill 400,000 Olympic-sized swimming pools.[137] If a company were not able to cover the cost of cleaning up tailings ponds, these costs could become major public liabilities.[138]

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Noise from propane cannons and floating scarecrows are used to deter migratory birds from landing in the oil-slicked tailings ponds.

PHOTO: DAVID DODGE, THE PEMBINA INSTITUTE

New technology that produces consolidated or thickened tailings is now being used to reduce the amount of fluid fine tailings and create tailings material that can be incorporated into a reclaimed landscape. But even with these technologies there will be fluid fine tailings that require special management. The industry is currently suggesting that these fluid fine tailings be placed in the mine pit after mining is complete and "capped" with water from the Athabasca River. In theory, these "end pit lakes" will be deep enough (65-100 metres) and of a great enough volume to ensure that the contaminants will be adequately diluted before draining into the Athabasca River watershed. Whether these lakes will support aquatic life and become sustainable aquatic ecosystems is still unknown.

Surface mine operators have committed to only discharging water that meets Alberta's Surface Water Quality Guidelines from these end pit lakes.[139,140] However, in the absence of any demonstration end pit lakes, the feasibility of this commitment or the necessary mitigation should it prove impossible remains unknown. Further, these guidelines do not include water quality limits for some of the chemicals, such as naphthenic acids, found in the fluid fine tailings that will be placed in the end pit lakes. Despite concern about the persistence and aquatic toxicity of naphthenic acids, Alberta Environment does not have any regulations for this toxin.[141]

At the joint federal-provincial regulatory panel hearing for Shell's Jackpine Mine – Phase 1 (now approved), the above issues were raised by a number of concerned stakeholders. In response, the Joint Panel, composed of a federal appointee and two members of the EUB, directed the EUB, Alberta Environment and Alberta Sustainable Resource Development to work with industry to develop tailings management performance criteria.[142] While this work was to be completed by June 30, 2005, the government has not, at the time of writing, published these performance criteria.

4.2.3 Freshwater Aquifers

Both oil sands mining and SAGD operations can impact freshwater aquifers by lowering their levels and creating a similar decrease in water levels in streams, ponds, lakes and wetlands that are connected to groundwater. The study of the hydrogeology of the region has only just begun. Consequently the flow of water between aquifers of varying depths is not well understood. When groundwater is pumped from a well, it causes a decrease in the pressure and water levels in the aquifer around the well. This decrease in pressure can cause water from aquifers closer to the surface to "leak" down, which can cause lowering of water in wetlands, reduced discharge of groundwater to streams, lakes and wetlands, and the lowering of the water table.[143] This is referred to as a drawdown effect.

Once the mine pit is excavated, groundwater levels are often lowered in the area to prevent flooding of the pits. Because multiple mines may be pumping water from an aquifer, the removal of groundwater from a large area of the landscape can lower the groundwater level in adjacent areas.

This can result in reduced groundwater flows to peatlands, wetlands and other surface water bodies.

The area impacted by the drawdown effect of removing this water can be up to 100 square kilometres.[144] Because prevention of pit flooding is considered essential, even if significant impacts are detected (e.g., wetlands drying out), there is not any possible mitigation.

In situ projects also impact freshwater aquifers through the SAGD technology used to recover bitumen. After the recovery, 90%-95% of the water, known as produced water, is de-oiled and treated so it can be reused in the steam generator. Because some of the water is lost in the treatment process, additional groundwater must be withdrawn. For every cubic metre of bitumen produced, about 0.2 cubic metres (200 litres) of additional groundwater must be added to produce more steam. To minimize the need to use freshwater aquifers, almost all SAGD projects in the region use some fresh groundwater mixed with saline groundwater (from deeper formations). While the use of saline groundwater for SAGD operations avoids additional demands on freshwater aquifers, treating it for use in the steam generators produces large volumes of solid waste.

4.2.4 Waste from Water Treatment

When saline water or produced water is being used at SAGD facilities for steam production, it must either be blended with fresh water or treated. The wastes from desalinization and other treatment processes are landfilled or injected into disposal wells that are drilled in deep, porous rock formations. Given the substantial volumes of water used by SAGD operations, the amount of solid waste produced is significant. For example, between 2005 and 2025 EnCana's Foster Creek SAGD operation will dispose of 48 million cubic metres of sludge into deep wells and send almost 260,000 tonnes of waste to landfill.[145]

To minimize the cost of transporting waste to regional landfills, many operators are constructing their own landfills and disposal wells. This has led to a proliferation of waste disposal facilities, another long-term environmental concern. The predominant use of landfills is also a serious issue because "disposing concentrates and effluent sludge in landfills could have significant environmental and ecological impact on the nearby soil and groundwater due to the high concentration of acids, hydrocarbon residues, trace metals and other contaminants."[146]

4.2.5 Troubling Trends in Water Use

Canadians are increasingly concerned about the long-term sustainability of surface and groundwater resources and the health of aquatic ecosystems. In the midst of a drought and public concerns about the quantity and quality of fresh water, the government of Alberta developed its Water for Life strategy in 2003.[147] During the development of this strategy, the public identified the use of water by the oil and gas sector as one of its key concerns.

During the consultation for the Water for Life Strategy in 2003, the public identified the use of water by the oil and gas sector as one of its key concerns.

PHOTO: DAVID DODGE, THE PEMBINA INSTITUTE

Despite the government's commitment to addressing this concern, water use for oil sands mining and SAGD operations is growing at an incredible rate. Of all the users of water from the Athabasca River, oil sands mining operations are by far the largest and the fastest growing. (Figure 16).

Approved oil sands mining operations are already licensed to divert 349 million m^3 of water per year from the Athabasca River. This is approximately two times the volume of water required to meet the municipal needs of Calgary, a city of almost one million people, for a year.[149] Further exacerbating the matter is the fact that, unlike most other water users, only one of the six approved oil sands mines discharges water back to the river. Planned oil sands mines, which have yet to receive approval, would push the cumulative withdrawal of water from the Athabasca River to 490 million m^3 per year (Figure 17).[150]

The amount of freshwater used for SAGD operations is also of concern. Most of the oil sands deposits in Alberta (93%) can only be accessed using in situ technologies such as SAGD, and therefore the future demand for groundwater is likely to grow exponentially. Because it is more expensive to drill wells into deep saline
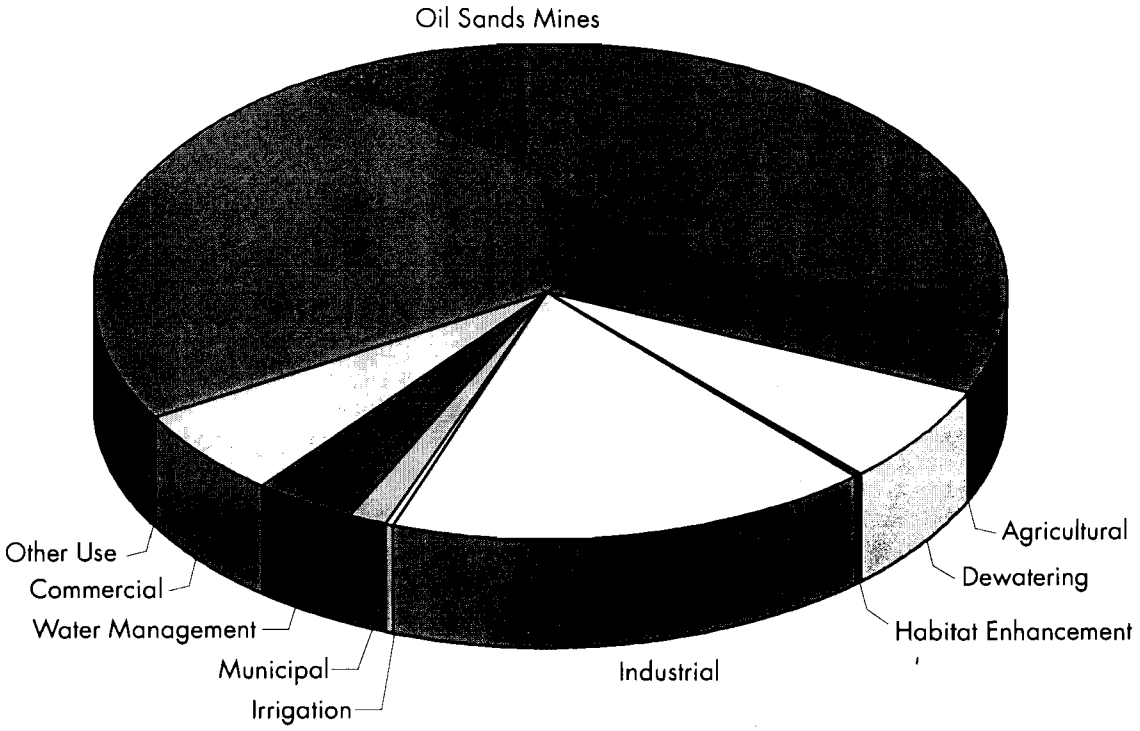
FIGURE 16: Licensed surface water allocations from the Athabasca River and its tributaries, 2005[148]