IHS CERA

Special Report

Critical Questions for the Canadian Oil Sands

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Contents

About this report

- **Purpose.** IHS CERA first researched questions critical for oil sands development in the 2009 Special Report *Growth in the Canadian Oil Sands: Finding the New Balance*. This update accounts for changes since that time and aims to illuminate critical questions for oil sands development, with a focus on areas of disagreement or uncertainty.

- **Context.** This report is part of a series from the IHS CERA Canadian Oil Sands Dialogue. The dialogue convenes stakeholders in the oil sands to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. Participants include representatives from governments, regulators, oil companies, pipeline companies, academia, and nongovernmental organizations. This report and past Oil Sands Dialogue reports can be downloaded at *www.ihs.com/oilsandsdialogue*.

- **Methodology.** This report includes multistakeholder input from a focus group meeting held in Washington, DC, on 13 November 2012 and participant feedback on a draft version of the report. IHS CERA also conducted its own extensive research and analysis, both independently and in consultation with stakeholders. IHS CERA has full editorial control over this report and is solely responsible for the report's contents. (See the end of the report for a list of participants and the IHS CERA team.)

- **Structure.** This report has an introduction, seven sections, and a conclusion.
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  - Part 2: Economics of oil sands compared with other supply sources
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Special Report

Critical Questions for the Canadian Oil Sands

Summary of key insights

This report is intended as a reference guide to the critical questions facing oil sands development. It updates our earlier work, the 2009 IHS CERA Special Report *Growth in the Canadian Oil Sands: Finding the New Balance*. Some key insights from this report are

- **Despite the rapid growth of US tight oil, the Canadian oil sands will continue to be an important component of US oil supply.** Even with tight oil, the United States will still need over 5 million barrels per day of net crude oil imports over the next two decades, and Canada will be key to helping meet this demand. Oil sands and tight oil are complementary—not competitive. New oil sands supply is expected to be heavy crude, while US tight oil is light crude. These two types of crude target different types of refineries.

- **Today more, not less, regulation, monitoring, and research are occurring in the oil sands.** The environmental impacts associated with oil sands growth are now better understood. Since the 2009 report, there are more rules and greater certainty about the sustainability of water use, the management of tailings accumulations, the impacts of land use on wildlife, and the impact of operations on regional air quality. However, questions still remain. For example, for mining operations, what will reclaimed land look like? And as in-situ operations expand, how will impacts on wildlife be managed?

- **Aggregate greenhouse gas (GHG) emissions from oil sands are regulated and are lower than often perceived, accounting for 7.8% of Canadian emissions and 0.14% of global emissions.** Oil sands GHG emissions are already regulated, and more rules are coming. Oil sands projects are subject to GHG regulation at the provincial level in Alberta, and Canada's federal government is developing new regulations as part of its nationwide target to reduce GHG emissions by 17% from 2005 levels by 2020—the same objective as the United States.

- **Oil sands crudes pose no greater risk to transmission pipelines than other crude oils.** Pipeline corrosion is well understood, and a number of scientific studies have concluded that the properties of oil sands crudes and pipelines that transport them are within the range of other crude oils. Consequently, oil sands crudes are no more likely to spill than other crudes.

– October 2013

Introduction

Development of the oil sands encapsulates the complexity the world faces on energy, environmental, and security issues. Canada and most other oil producers are searching for the right balance between increasing oil supply—to accommodate growing economies, aspirations for higher living standards, and greater energy security—and protecting the environment.

This report is a new appraisal, following on the 2009 IHS CERA Special Report *Growth in the Canadian Oil Sands: Finding the New Balance* on the critical issues for oil sands development, and incorporates four additional years of research and experience.

Like our original report, this update identifies areas of uncertainty or disagreement that are central to the future development of the Canadian oil sands. Our goal is to create a reference document that illustrates complex issues clearly, to identify what is known and unknown, and to provide a common understanding for future discussions on oil sands development.

This report has an introduction, seven sections, and a conclusion:

- Introduction
- Part 1: The role of oil sands in US oil supply
- Part 2: Economics of oil sands compared with other supply sources
- Part 3: Environmental regulations
- Part 4: Regional environmental impacts: Air, land, water, and waste
- Part 5: Greenhouse gas emissions
- Part 6: Technology
- Part 7: Pipeline transport of oil sands
- Conclusion

Throughout this report, we refer to a number of unique oil sands extraction methods and marketable products (see the box “Canadian oil sands primer” for definitions).

Canadian oil sands primer

The signature feature of the oil sands is their immensity. Current estimates place the amount of oil that can be economically recovered from Alberta's oil sands at 168 billion barrels, making oil sands the world's third largest proven oil reserve (after Saudi Arabia and Venezuela). However, with advances in technology, as much as 315 billion barrels could ultimately become accessible from the oil sands.

The oil sands are grains of sand covered with water, bitumen, and clay. The "oil" in the oil sands is bitumen, an extra-heavy crude oil with high viscosity. Raw bitumen is semisolid at ambient temperature and cannot be transported by pipeline. It must first be diluted with light oil or converted into a synthetic light crude oil. Several types of crude oils are produced from bitumen.

Bitumen blends. To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons (often natural gas condensates) into a bitumen blend. A common bitumen blend is dilbit—short for diluted bitumen—typically about 70% bitumen and 30% lighter hydrocarbons. Going forward we expect the vast majority of oil sands supply growth to be bitumen blends.

Synthetic crude oil (SCO). SCO, which resembles light sweet crude oil, is produced from bitumen in refinery conversion units (called upgraders) that turn very heavy hydrocarbons into lighter, more valuable fractions from which gasoline and diesel are manufactured. We do not expect meaningful future growth in SCO supply because of challenging economics.[1]

Oil sands are unique in that they are extracted through mining and in-situ processes.

Mining. About 20% of currently recoverable oil sands reserves are close enough to the surface to be mined. In a surface-mining process similar to coal mining, the overburden (vegetation, soil, clay, and gravel) is removed and stockpiled for later use in reclamation. The layer of oil sands ore is excavated using massive shovels that scoop the material, which is then transported by truck to a processing facility. The original mining operations always marketed SCO. However, a new mining operation (which started up this year) does not include an upgrader and will instead ship bitumen blend straight to market. Slightly less than half of today's production is from mining, and we expect this proportion to be about 40% by 2030.

In-situ thermal processes. About 80% of the recoverable oil sands deposits are too deep to be mined and are recovered by drilling. Thermal methods inject steam into the wellbore to lower the viscosity of the bitumen and allow it to flow to the surface. Such methods are used in oil fields around the world to recover oil. Thermal processes make up 39% of current oil sands production, and two commercial processes are used today:

- **Steam-assisted gravity drainage (SAGD)** is the fastest growing method, accounting for 25% of production in 2012 and by 2030 is is projected to account for almost 45% of oil sands production.
- **Cyclic steam stimulation (CSS)** was the first process used to commercially recover oil sands in situ. Currently making up 14% of total production, CSS is projected to account for less than 10% of total production in 2030.

Primary production. The remaining oil sands production is referred to as primary production. This material is less viscous and is extracted without steam, using conventional oil production methods. Primary production currently makes up 12% of total output and is projected to be less than 5% by 2030.

1. For more information on upgrading economics see the IHS CERA Special Report *Extracting Economic Value from the Canadian Oil Sands: Upgrading and refining in Alberta (or not)?*

Part 1: The role of oil sands in us oil supply

This section explores the current and possible future role of oil sands supply in the US market and in strengthening North American energy security. We include a brief explanation of why increased oil sands supply to the United States is unlikely to contribute to higher gasoline prices, which has been a concern in the dialogue surrounding oil sands.

What is the role of oil sands in US and global oil supply today?

Canada is the largest supplier, by a wide margin, of imported oil to the United States. In 2012 Canadian crude oil imports to the United States totaled about 2.4 million barrels per day (mbd), or about 28% of total US crude imports. Much of this—1.5 mbd, or about 18% of US imports— is from the oil sands.[2] In fact, the oil sands alone are now the largest foreign source of US oil supply, providing more oil than Saudi Arabia or Mexico (the second and third largest suppliers), which accounted for 16% (1.4 mbd) and 11% (1.0 mbd), respectively, in 2012. Even in the past few years, a time when total US oil imports have fallen sharply owing to the North American tight oil revolution and weak domestic demand, Canada's share of total US crude imports rose from 21% in 2010 to 28% in 2012. Despite the rapid growth of tight oil, we expect that the United States will still need over 5 mbd of net oil (liquids) imports each year over the next two decades. Oil sands are expected to remain an important pillar of US supply to meet this demand. Moreover, the two supply sources, tight oil and the oil sands, are complementary—not competitive. The vast majority of new supply from Canada is heavy crude, while most new US supply from tight oil is light crude. These two types of crude target different types of refineries, and both are important supply sources for North America.

More generally, Canada—and the oil sands in particular—has been a major source of global oil supply growth over the past decade and is poised to continue to be a key source of supply growth for the world. Canada is one of four countries included in what IHS CERA has called the "axis of oil supply growth," along with the United States, Brazil, and Iraq. We expect western Canadian crude oil output to rise from 3 mbd in 2012 to 5.9 mbd by 2030.[3] Considering other anticipated sources of growth, the oil sands could account for 16% of all new production globally until 2030.[4]

Although markets for oil sands are expected to diversify gradually, a large part of new oil sands supply through 2030 is expected to go to the United States—as virtually all of the production does today. By 2030, the United States could import more than 4 mbd of oil sands crudes from Canada.[5]

How does oil sands production strengthen North American energy security?

The presence of the oil sands within the continent increases North American energy security. Increasing supply from Canada allows the United States to reduce its dependence on more distant supplies of oil by tanker, often from regions that are less stable and more susceptible to disruption. Pipeline and rail links between the United States and Canada constitute a "hardwired" link of Canadian oil to the US market—very different from waterborne shipments that can be diverted, even while en route.

2. The estimate of volume of US imports of oil sands is based on data from the Canadian National Energy Board (NEB) and the US Energy Information Administration (EIA). We have added 250,000 barrels per day (bd) to the reported values from the NEB to account for some oil sands blends that the agency categorizes as heavy conventional crudes.

3. Western Canadian production estimate does not include imported diluents added to non-upgraded bitumen for transport by pipeline.

4. This assumes that oil sands production grows by 2.6 mbd between 2012 and 2030 (not including diluents added to oil sands for shipping) and that over the same period global production grows by over 16 mbd.

5. Between 2012 and 2030 western Canadian supply is projected to grow by 2.9 mbd. Assuming that Gateway, Trans Mountain Expansion, and Energy East pipelines are constructed by 2030, there is the potential for 1.9 mbd of new western Canadian supply to be exported to other markets. This assumes that some oil transported by these pipelines will still be exported to the United States, by tanker or barge.

Complex refineries on the US Gulf Coast (USGC), the largest heavy oil refining complex in the world, require heavy crude like bitumen blends from the Canadian oil sands. The region currently relies on heavy crude oil from Mexico and Venezuela. Mexico has struggled to maintain its heavy crude output to the USGC. Between 2005 and 2012, imports of Mexican heavy crude to the United States have declined by about half.[6] In the first six months of 2013, the United States averaged just over 750,000 bd of heavy crude oil imports from Venezuela.[7] There is also some uncertainty surrounding future supply from Venezuela, stemming from a recent history of declining production. Canadian heavy supply offers an alternative to less certain heavy crude suppliers.

All sources of oil supply contribute to global spare capacity and price stability. All else being equal, without the Canadian oil sands, the world's spare production capacity cushion would be less than it is now. The thinner this cushion is, the more susceptible the price of oil is to unanticipated changes in supply and demand. By the end of this year Canadian oil sands production will be roughly equivalent to about two-thirds of estimated global spare production capacity for 2013.[8] We expect global spare production capacity in 2020 to average about 4.3 mbd, which is higher than the 2 to 3 mbd of recent years. The 1.4 mbd of oil sands production growth over this time would be an important contribution to a greater global supply cushion.

How will new oil sands pipelines affect US gasoline prices?

For the past few years, the price of inland North American crudes has been below—significantly at times—the price of crude oil on the USGC. These North American crudes—not only from Canada and the oil sands but also from North Dakota—have traded at a discount compared with the cost of similar crudes available globally. This is because the expansion of the inland pipeline network has struggled to keep pace with the rapid growth of onshore supply, resulting in a glut of oil in the US Midwest. If proposed pipelines are completed, the oversupply situation in the US Midwest will be resolved, and crude prices would strengthen as they reconnect with global market prices.

There is a view that this would also cause prices for refined products, such as gasoline, in the Midwest to increase. However, this is not the case.

The global price of oil is the most important factor shaping global and US gasoline prices. Although the price of inland North American crudes has been below the price of crudes on the USGC, this spread has not been reflected in inland North American gasoline prices, which have tracked USGC prices. For example, in 2012 the difference between Louisiana Light Sweet on the USGC and West Texas Intermediate (WTI) in Cushing, Oklahoma, averaged over $17 per barrel, compared with an average of $3.35 in 2010, before infrastructure bottlenecks became pronounced. Despite the wide price difference for crudes in the Midwest compared with the USGC, the price of gasoline in the two areas has remained very close. In 2012 the price in the Midwest averaged $2.89 per gallon, only $0.02 higher than on the USGC. This is because the price of gasoline in both regions, and elsewhere in the United States, is set on the world market. Prices in all regions are linked because gasoline is shipped from the USGC through the refined product pipeline network and by water to consumers in the Southeast, the East Coast, the Midwest, and the West. As a result, increased oil sands imports to the USGC and other US markets will not have a material impact on US gasoline prices in any market. However, as oil sands production expands, as discussed above, it can help boost global spare capacity, which can help moderate global prices, which in turn affects US gasoline prices.

6. Mexican Maya imports in 2012 were 0.7 mbd, compared with 1.3 mbd in 2005.

7. We define heavy crude oil as having an API gravity of less than 28 degrees. Source of import data: US EIA.

8. By the end of 2013, oil sands production of SCO and non-upgraded bitumen is expected to average over 1.9 mbd. We project that global spare capacity will average about 2.9 mbd in 2013.

Part 2: Economics of oil sands compared with other supply sources

This section explores how the economics of oil sands production compare with other sources of supply.

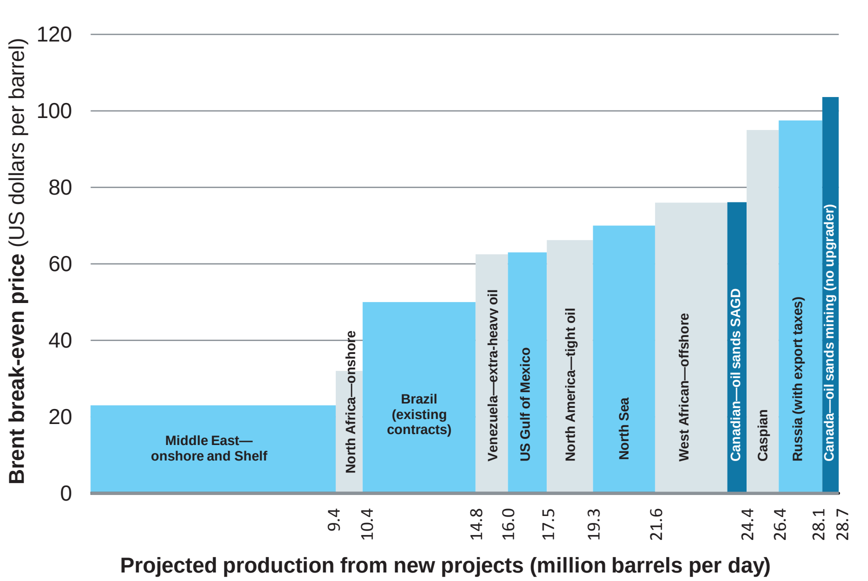
How costly are the oil sands compared with other new sources of supply?

Oil sands are one of a group of higher-cost supply sources that are being developed globally. Oil sands development costs are higher than those for conventional resources being developed in the Middle East and North Africa. However, the cost of oil sands production that uses SAGD technology is in the same range as new supplies from the North Sea, Brazil offshore, and West Africa offshore.

Figure 1 compares the economics of a number of oil projects currently under development. The projects, grouped by type, represent about 90% of new production capacity expected to come online between now and 2020.[9] The economic analysis of each development first considers finding, development, and production costs, then taxes and royalties, transportation, and crude quality differences. It then evaluates the threshold Brent price (a global crude benchmark price) required to obtain a reasonable return on capital investment—we assume 10% for oil sands and North American tight oil and 15% for all other international projects, which have a higher investment risk.[10]

FIGURE 1

Brent break-even price for new crude supply to 2020



Note: The required Brent oil price is based on full-cycle costs that include finding, development, and production and an internal rate of return (IRR). IRR is 15% for all areas, except for Canadian oil sands and North American tight oil, for which it is 10%. Middle East onshore and shelf breakeven price is for Saudi Arabia. North African onshore breakeven price is for Libya. For Venezuela extra-heavy, breakeven price is for projects under the strategic association agreements for production of extra-heavy oil in the Orinoco region, which includes a royalty holiday and tax benefits for vertically integrated producers (i.e., those with both upstream and upgrading operations). For Brazil, production is all under existing concession royalty contracts, with the exception of 600,000 bd from Franco. Franco is a "Transfer of Rights" field, i.e., a field that the Brazilian government gave to Petrobras under special terms to capitalize the company prior to its initial public offering. For Canada oil sands mining, the breakeven price assumes that no upgrader was used and that the facility markets dilbit. The breakeven prices for the oil sands and tight oil are for WTI and are converted into a Brent basis by adding $4 to reflect quality differentials and the cost of transporting the crude from inland areas in North America to a port where it competes directly with Brent (assumed to be on the US East Coast). This $4 supplement represents our annual average price outlook to 2020 for WTI less Brent.

Source: IHS Energy

9. The projects in Figure 1 represent about 29 mbd of new supply—about 90% of the total new capacity we expect to come online by 2020.

10. Brent crude oil is a globally traded crude, based originally on North Sea production, that is often used as a global crude benchmark price.

Part 3: Environmental regulation

With oil sands production expected to more than double between 2012 and 2030, there are concerns about whether existing environmental regulations can address the impacts of such growth.[11] Provincial and federal governments in Canada are responding by issuing new regulations and by expanding monitoring. This section highlights key changes to the environmental regulatory framework for the oil sands in the past few years. Part 4 examines in detail the specific regional environmental impacts and regulation for air, water, land, and waste in the oil sands region. Part 5 presents an outlook for greenhouse gas (GHG) emissions from the oil sands.

How does environmental regulation of oil sands compare with resource development in other regions?

Environmental regulation of oil sands projects is generally similar to that of natural resource development projects in peer areas. IHS CERA compared regulation in oil sands to two peers: South Australia's mining sector and Alaska's mining and oil sectors. Similarities in regulation include the project approval process, the use of inspections and nature of enforcement, and requirements for environmental monitoring and site closure.[12]

What changes are under way for oil sands regulation?

Over the past few years, Canada's federal and Alberta's provincial governments introduced new policies and regulations to address the growing scale of oil sands development. The most significant of these aim to

- Clarify and streamline the project environmental assessment process
- Move to a system that assesses the cumulative effects of development
- Consolidate and enhance environmental monitoring

Clarifying and streamlining the project environmental assessment process

Each oil sands facility undergoes a project-specific review process at the provincial level. In addition, projects may also require federal permits that can involve a federal environmental review.[13] Projects that trigger multiple federal permits or are of high public interest may require a coordinated federal review by a panel. Where overlap occurs with provincial reviews, the review panel may be held in cooperation with the province; this is called a joint federal-provincial review panel. Joint reviews are generally more exhaustive than other reviews because they typically involve larger, more complex projects that have the potential for significant environment impacts.

It is a common misconception that the sole purpose of an environmental review is to deliver a yes or no decision. Though review panels do make recommendations, environmental assessments also serve as an important planning tool to inform project proponents, regulators, and stakeholders about the potential impacts of the development. It provides a forum for all parties to discuss and, to the extent possible, mitigate

11. Oil sands production of SCO and non-upgraded bitumen is expected to rise by 2.6 mbd between 2012 and 2030, to nearly 4.4 mbd. When diluent is included (some of which is imported into Canada), total oil sands supply is expected to rise by 3.5 mbd, to 5.6 mbd, over this period.

12. See the IHS CERA Special Report *Assessing Environmental Regulation in the Canadian Oil Sands*.

13. Key federal departments/agencies with regulatory responsibilities most likely involved in oil sands developments include the Canadian Environmental Assessment Agency, Transport Canada, the Department of Fisheries and Oceans, and Environment Canada.

potential adverse effects from the development.[14] Panel recommendations take into account whether potential impacts are justifiable. Rarely does a project go through the environmental review process only to be denied.[15]

In recent years, industry and governments have argued that the review process has become increasingly burdensome—raising costs and uncertainty for the companies seeking to undertake industrial projects in Canada. For instance, projects may not always trigger a joint review panel but may still require multiple permits from both levels of government. Separate reviews by both federal and provincial regulators increase both time and cost for project proponents. Also, when joint review processes are triggered, they have become increasingly lengthy. In one recent example, an oil sands project took nearly six years to receive a final decision.[16]

Greater public interest, even from organizations and people far removed from the project, has been one factor that has contributed to a lengthier review process. In one recent example, more than 4,400 individuals asked to speak at public hearings of the joint review of the proposed Northern Gateway pipeline. This volume of requests contributed to a one-year extension of the regulatory time frame.[17] A review of the Northern Gateway hearing database shows requests to address the panel from across Canada (British Columbia, Alberta, Saskatchewan, Ontario, Québec, and the Maritimes), but also from the United States and as far away as England.[18]

With an eye toward reducing duplication and improving the timeliness of reviews, in 2012 the Government of Canada revamped the federal rules for environmental assessments of industrial projects, including oil sands.[19] Key aspects of the new Act include predefined criteria for determining when federal environmental assessments must be conducted; time limits for reviews (12 months for a comprehensive environmental review and 24 months for a joint review panel); the potential for provinces to substitute their environmental reviews in place of a federal review; and restricting those who can orally address the review panel to subject matter experts and those directly affected by the proposed project.[20]

The revised federal environmental assessment rules have faced some criticism for being potentially less rigorous. This is in part because the new rules impose time limits and reduce public participation, but also because they are expected to result in fewer federal reviews owing to possible substitution with provincial processes. However, the impacts of the new process will become clearer over time, as reviews of the first tranche of projects subject to the new guidelines run their course.

14. For more information, see Canadian Environmental Assessment Agency, Basics of Environmental Assessment, *www.ceaa-acee.gc.ca/default.asp?lang=en&n=B053F859-1#gen02*, accessed 9 October 2013.

15. The last major project that was denied approvals was the Prosperity Mine in British Columbia, in 2010. The federal review found that the significant adverse effects could not be justified. This resulted in the reworking of the project proposal, and the revised project is back under review, with a decision expected early in 2014. For more information, see *www.ceaa.gc.ca/050/document-eng.cfm?document=46185*, accessed 29 July 2013; and for the new review submitted 9 August 2011, see *www.ceaa-acee.gc.ca/050/details-eng.cfm?evaluation=63928*, accessed 29 July 2013. In another rare example, although not a panel review, in 2012 the Alberta Energy Regulator (at the time the Energy Resources Conservation Board) denied E-T Energy Ltd.'s Poplar Creek project because the regulator did not have enough information to conclude if the technology E-T wished to pilot could sustain commercial production rates. For more information, see *www.e-tenergy.com/media/files/upload/ETEL_PR_June_14_2012_ERBC_Decision_sxq.pdf*, accessed 31 July 2013.

16. The Jackpine Expansion review is closing in on six years (20 December 2007 to present). Barring any extensions, a final decision is expected by the Minister of Environment before to 6 November 2013—120 days following the submission of the joint review panel report on 9 July 2013. Source: Canadian Environmental Assessment Agency, Jackpine Mine Expansion Project Documents, *www.ceaa-acee.gc.ca/050/documents-eng.cfm?evaluation=59540*, accessed 23 July 2013.

17. As of July 2013 the Joint Review Panel had received 4,455 requests to make an oral statement and 5,444 letters of comment. Source: Enbridge Northern Gateway Project Joint Review Panel Public Registry, "F – Letters of Comment" and "G – Requests to Make an Oral Statement," *https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/384192/620327/customview.html?func=ll&objId=620327&objAction=browse&sort=-name&redirect=3*, accessed 14 October 2013. On 6 December 2011, the Joint Review Panel issued a new hearing schedule that delayed the final Northern Gateway project decision until late in 2013, a year later than previously expected.

18. Enbridge Northern Gateway Project Joint Review Panel Public Registry, "G – Requests to Make an Oral Statement," *https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/384192/620327/G_-_Request_to_Make_an_Oral_Statement_file.html?nodeid=838062&vernum=0*, accessed 14 October 2013.

19. The federal government enacted the Canadian Environmental Assessment Act, 2012, which replaced a similarly named law passed in 1992. For more information, see *www.ceaa-acee.gc.ca/default.asp?lang=en&n=16254939-1*, accessed 9 October 2013.

20. For more information on the Canadian Environmental Assessment process and Act, see *www.ceaa-acee.gc.ca/default.asp?lang=en&n=B053F859-1*, accessed 29 July 2013.

Moving to a system that assesses the cumulative effects of development

Although each oil sands project must undergo a thorough review process, concerns about the cumulative impact of development on the oil sands region as a whole have emerged owing to the scale of development and the growing number of projects. In response to this issue, in 2012 Alberta introduced a regional plan for the main oil sands development area, the Lower Athabasca Regional Plan (LARP).[21]

Under LARP, industrial project environmental reviews take into account regional environmental limits in addition to project-level requirements. Environmental impacts (including on air and water quality) from all industrial development (including oil sands) are required to stay within the regional limits.[22] Actions to mitigate negative environmental effects must be taken to address upward trends before regional limits are reached. For now, indicators for regional air and water quality are still below limits. This is not a surprise, since the concern is directed more toward future effects if all approved projects are constructed. It remains to be determined how individual facilities, not only from the oil sands but from all sectors, might be required to reduce their environmental impact in the event that levels approach regional limits, since the burden is on all sources from the area rather than an individual facility.

In addition to managing the cumulative effects of development, LARP also designates new conservation areas: 22% of the region's total area is protected, an area almost the size of the state of New Jersey.[23]

Although LARP was announced last year, it will take several years for all aspects of the plan to come into force. Some initiatives are taking longer than anticipated, such as the groundwater management framework for the lower Athabasca, the biodiversity framework, and the tailings management framework. Specific examples of regulatory changes resulting from LARP are highlighted, where appropriate, in Part 4, which reviews regional environmental impacts.

Consolidating and strengthening environmental monitoring

Regional air and water quality are monitored in the oil sands region by the Wood Buffalo Environmental Association (WBEA) and the Regional Aquatics Monitoring Program (RAMP), respectively.[24] WBEA, which has been in place for over a decade, actively monitors air quality at 16 locations (18 by the end of 2013), and periodically at 23 boreal forest sites, and measures some 214 air quality indicators.[25] In addition, each oil sands facility is required to monitor and report on air and water quality and biodiversity for each site.

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21. The Lower Athabasca region is the main oil sands development area in Alberta, accounting for 83% of the province's oil sands resources. The oil sands in Alberta, in turn, represent more than 95% of Canada's total oil reserves. LARP is the first of seven regional plans under Alberta's Land-use Framework to be approved. See Government of Alberta, *Lower Athabasca Regional Plan 2012–2022*, 2012, *https://landuse.alberta.ca/LandUse%20Documents/Lower%20Athabasca%20Regional%20Plan%202012-2022%20Approved%202012-08.pdf*, accessed 13 September 2013. For resource estimates, see Alberta Energy Regulator, ST-98-2013 *Alberta's Energy Reserves 2012 and Supply/Demand Outlook 2013–2022*, *www.aer.ca/documents/sts/ST98/ST98-2013.pdf*.

22. Other major industrial sectors in Alberta include forestry, natural gas, minerals, and agriculture.

23. The total Lower Athabasca region is 35,989 square miles (sq mi), or 93,212 square kilometers (sq km). Within this region, the total conservation areas are more than 7,722 sq mi or 20,000 sq km. The area of the state of New Jersey is 8,204 sq mi, or 21,248 sq km. Sources: Government of Alberta, Lower Athabasca Regional Plan 2012–2022, 2012, *https://landuse.alberta.ca/LandUse%20Documents/Lower%20Athabasca%20Regional%20Plan%202012-2022%20Approved%202012-08.pdf*, accessed 13 September 2013; and The State of New Jersey, Fast Facts, *www.state.nj.us/nj/about/facts/facts/*, accessed 13 September 2013.

24. Both WBEA and RAMP may be subject to change owing to the implementation of a Joint Federal-Provincial Monitoring Program. For more information on WBEA, see *www.wbea.org*. For more information on RAMP, see *www.ramp-alberta.org*.

25. Periodic monitoring, or passive monitoring, is more useful to detect longer-term trends, whereas active monitoring provides more up-to-date air quality measurements. Source: WBEA monitoring information provided by WBEA.

In 2012 the Alberta and federal governments jointly unveiled a plan to strengthen monitoring activities in the oil sands region. Scheduled for full implementation by 2015, the Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring was a response to concern by scientists and governments in Canada that the existing level and structure of monitoring in the oil sands regions were insufficient to capture the effects of oil sands development. The new plan will increase the number of sites and extend the reach of the existing regional monitoring system.[26] One goal of the new program is to measure the impacts from oil sands development on regional air, water, land, and biodiversity in an integrated way. Another goal is to ensure that the system is adaptive, incorporating experience (gained through past monitoring) and new scientific and technical knowledge. Transparency is another objective. A new data management system, the Oil Sands Data Management Network, will be used to increase public access to monitoring data. The improved monitoring is critical to supporting LARP, as thresholds will need to be measured at the regional level to understand whether cumulative effects are within mandated limits.

26. For more information on the joint monitoring plan, see Canada-Alberta Oil Sands Environmental Monitoring Information Portal, *www.jointoilsandsmonitoring.ca*. For information on concerns about prior monitoring, see Environment Canada, Lower Athabasca Water Quality Plan, Phase 1, *www.ec.gc.ca/Content/8/A/1/8A1AB11A-1AA6-4E12-9373-60CF8CF98C76/WQMP_ENG.pdf*, accessed 13 September 2013.

Part 4: Regional environmental affects: Air, land, water, and waste

This section examines the regional environmental impacts associated with oil sands development: air pollutants, land use and reclamation, water use, and waste (tailings). GHG emissions are examined in the next section.

Air pollutants

Oil sands facilities emit air pollutants that degrade air quality. The type of air pollutants emitted by oil sands operations are similar to those found in urban or other industrial areas.[27] When air pollutants find their way back to earth, they can accumulate in water and soil and can affect human and wildlife health if present at sufficient concentrations.

Air quality

Compared with that of major urban centers in Alberta and Canada, the air quality in the oil sands region is better on average.[28] Although most airborne contaminants remain relatively localized—within about 15 mi (25 km) of oil sands operations—evidence has been found of contaminants, specifically PAH, accumulating in lakes up to 55 mi (90 km) away.[29] However, current measured levels of PAH concentrations in lakes do not pose a health risk and are comparable with levels found in water in urban environments. As development expands other evidence of industrial activity will grow.

Regulating and monitoring

Regulations are in place to limit air emissions from each oil sands facility.[30] Facilities must monitor and report air emissions to the government on a regular basis. In addition, new regional limits were implemented in 2012 under the Alberta Air Quality Management Framework (part of the Land-use Framework, discussed above). These new thresholds aim to manage emissions from all sources, including industrywide impacts on the region's air quality (as opposed to facility-level emissions limits). A key requirement in enforcing regional air pollution limits is measuring pollutants over a wide area. Plans to strengthen regional monitoring are discussed in more detail above in Part 3.

Future levels of air pollution and regional thresholds

Although air quality in the oil sands is typically better than in major urban cities, air pollutants are set to increase in line with rising oil sands production. Indeed, a recent cumulative environmental assessment completed as part of an oil sands mine regulatory review has confirmed that if all planned oil sands projects are built and no new air pollutant measures are taken, the levels of air pollutants such as nitrogen dioxide (NO_2) and sulfur dioxide (SO_2) could exceed regional limits under Alberta's new air quality regulations.[31]

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27. Some common air pollutants resulting from oil sands operations are sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulate matter. Other pollutants include volatile organic compounds, total reduced sulfurs, and polycyclic aromatic hydrocarbons (PAH).

28. Using a modified Environment Canada/Health Canada Air Quality Health Index (AQHI), for 98% of the time over the past five years, air quality in the oil sands region posed a low risk to human health. Oil sands air quality was estimated from the share of low risk records (as measured by an AQHI index of three or less) from 2007 to 2012 from the summation of records for Fort McMurray and Fort McKay. Urban records include Edmonton and Calgary, which both reported that 81% of the time, air quality was low risk over last five years. For more information, see the Clean Air Strategic Alliance, Data Warehouse, *www.casadata.org*.

29. See K. Percy (2013), *Alberta Oil Sands: Energy, Industry, and the Environment, Developments in Environmental Science 11, Oxford, UK*; *http://www.elsevier.com/books/alberta-oil-sands/percy/978-0-08-097760-7#*, accessed 9 October 2013. Also, see J. Kurek et al. (2013), "Legacy of a half century of Athabasca oil sands development recorded by lake ecosystems," Proceeding of the National Academy of the Sciences of the United States of America, *http://www.pnas.org/content/early/2013/01/02/1217675110*, accessed 9 October 2013.

30. Air pollution regulations are diverse and are contained in a variety of federal and provincial legislation in Canada. At the federal level, the Canadian Environmental Protection Agency Act 1999 sets limits and requires reporting of industrial emissions. In Alberta, the Air Quality Management System provides provincial direction.

31. Source: Shell Canada Energy's Response to the Joint Panel's Information Requests, Jackpine Mine Expansion Joint Panel Review, September 7, 2012, *www.ceaa-acee.gc.ca/050/documents/p59540/81301E.pdf*, accessed 14 October 2013.

If levels approach regional limits, industry would need to reduce pollutant levels. Reductions can be achieved at a financial cost, but currently it is unclear who would bear this burden—whether it would be industrywide or just involve the most recent facility. Some potential abatement options include obtaining newer, more efficient, mining trucks or deploying new technologies, such as emission scrubbers or systems to capture key air pollutants.

Land use and reclamation

The decision to develop the oil sands has resulted in land being disturbed. Oil sands operations require land to access oil sands deposits and to house their extraction, processing, and transportation equipment. The predevelopment state of land in the oil sands region is boreal forest. Evergreen trees dominate the landscape, and 30–40% of the boreal areas are wetlands.

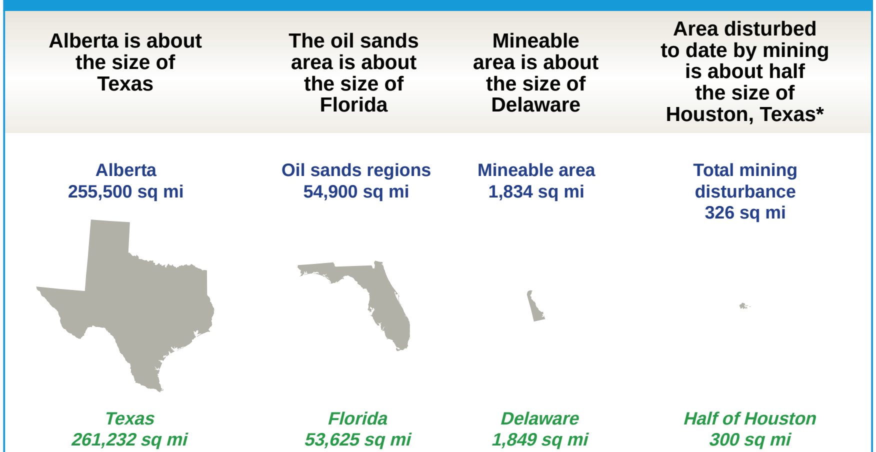
Land disturbed by oil sands operations is degraded or removed from the ecosystem for a period of time. This affects wildlife and local residents, particularly Aboriginal peoples who use the land for traditional activities such as hunting, trapping, and fishing. As the scale of oil sands development has grown, the amount of disturbed land has increased. The degree to which land is disturbed and the challenge of reclamation vary according to whether the oil sands operation is in-situ or mining. These differences are highlighted below.

Footprint of oil sands development

As shown in Figure 2, Alberta is about the size of Texas, and the oil sands region within the province is about the size of Florida. Within the oil sands region, the area suitable for surface mining is just over 3% of the total oil sands area—an area comparable to the state of Delaware. The remaining 97% of the oil sands areas are suitable for in-situ extraction techniques. At any given time, only a small part of the mineable or in-situ areas is expected to be under active development. As of the end of 2012, about one-fifth of the total mineable area had been disturbed—an area 326 sq mi in size, similar to half of Houston proper. While the potential in-situ development area is a considerable size, individual in-situ project footprints and their resulting disturbance are small compared with mining operations and are more comparable to conventional oil and gas footprints, with well pads and pipelines.[32]

FIGURE 2

Illustrative comparison of various oil sands areas to some US areas



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Note: Images are approximations and are not to scale.
*Includes area under active disturbance, 296 square miles and reclaimed areas, 30 square miles as of the end of 2012.
Source of oil sands areas from Alberta Energy, www.energy.gov.ab.ca/LandAccess/pdfs/OSAagreeStats.pdf; source of oil sands disturbance Alberta Environment and Sustainable Resource Development (ESRD), Oil Sands Portal, Oil Sands Mine Regional Totals for Reclamation and Disturbance Tracking by Year, environment.alberta.ca/apps/OSIPDL/Dataset/Details/27#, accessed 24 September 2013.
Source of area of US states (2010), US Census Bureau, State and Country QuickFacts, quickfacts.census.gov/qfd/index.html; area of Houston proper from Greater Houston Convention and Visitors Bureau, www.visithoustontexas.com/travel-tools/about-houston/facts-and-figures/.
Source: IHS CERA

32. Alberta occupies 255,000 sq mi (661,000 sq km), and oil sands deposits in Alberta underlie an area of 54,900 sq mi (142,200 sq km). The minable region occupies an area of about 1,833 sq mi (4,750 sq km). The total area disturbed by mining operations as of the end of 2012 was 326 sq mi (844 sq km) and is made up of reclaimed land area of 30 sq mi (78 sq km) and active mining disturbance of 296 sq mi (766 sq km). The total area suitable for in-situ development is 53,070 sq mi (137,450 sq km). Disturbed land is defined as an area where natural vegetation has been partially or totally cleared, wetlands have been drained, or the land has otherwise been changed from its natural ecological state. Source of disturbance data: Alberta Environment and Sustainable Resource Development (ESRD), Oil Sands Portal, Oil Sands Mine Regional Totals for Reclamation, and Disturbance Tracking by Year, *environment.alberta.ca/apps/OSIPDL/Dataset/Details/27#*, accessed 24 September 2013.

Land disturbance and reclamation: mining

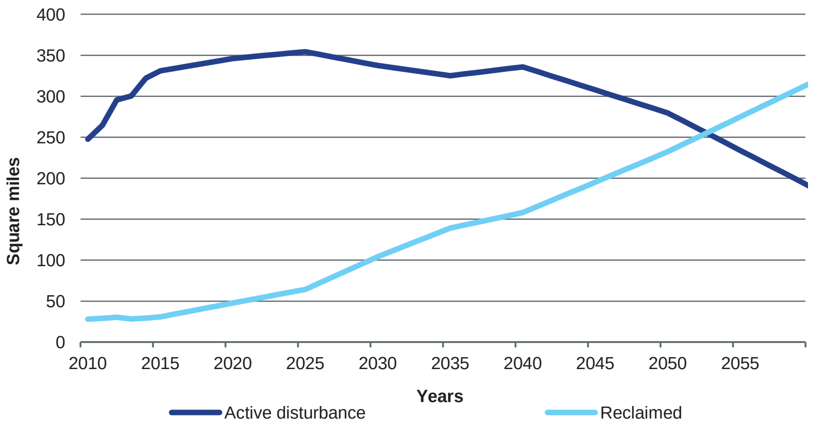
Although the total mineable area is smaller than the in-situ development area, mining requires the removal of all material overlaying the oil sands deposits before mining can commence.[33] This represents a total loss of the ecological character of the land for a period of time and highlights the importance of reclamation in returning the lands to productive use.

Large-scale commercial oil sands mining began over 45 years ago, in 1967.[34] As new projects have come online and mining has progressed, the amount of disturbed land has increased. However, reclamation has not progressed at the same rate. With mining operations lasting for more than 40 years, the current practice has been to mine-out large areas before performing large-scale reclamation. At the end of 2012, total active disturbance (disturbed land less reclaimed land) was 296 sq mi—30 sq mi less than shown in Figure 2, which accounts for areas under various stages of reclamation (0.4 sq mi of this has been certified as reclaimed).[35] Increasingly governments and industry are looking at ways to accelerate reclamation. One often discussed method is progressive reclamation, which involves planning a mine to more readily allow operators to reclaim as they go.

Although the amount of disturbed land has been growing steadily, based on expectations set forth in projects' approved reclamation plans, the pace of growth is projected to slow. Figure 3 depicts the result of the latest mine reclamation and closure plans submitted to Alberta ESRD. As older mines approach the end of their life, the pace of reclamation is projected to pick up. In the absence of new mining projects, between now and 2060 the total area of active disturbance is expected to be at most 20% larger than it is today.[36]

FIGURE 3

Oil sands mining footprint: Outlook for disturbed and reclaimed land



Note: Historical data used for years 2010 to 2012 inclusive form Alberta Oil Sands Portal. See: Alberta ESRD, Oil Sands Mine Regional Totals for Reclamation and Disturbance Tracking by Year Description, http://environment.alberta.ca/apps/OSIPDL/Dataset/Details/27, accessed 17 October 2013. Mine disturbance and reclamation for the years 2013, 2014, 2015, and every five years after to 2040, then 2050 and 2060 from mine reclamation and/or mine closure plants submitted to Alberta ESRD. Line interpolated between data points. Provided directly by Alberta ESRD.Mine reclamation and/or mine closure plans included: Syncrude Canada Ltd. Mildred Lake Canada (2011) and Aurora (2011), Canadian Natural Resources Horizon (2011), Suncor Energy Inc. base mine (2011), and Fort Hills (2011), Shell Muskeg River (2012), and Jackpine (2011), Imperial Kearl (2011).

Source: IHS CERA and Alberta ERSD

When land is disturbed on the scale of oil sands mining operations, the land is permanently changed. The extent to which reclaimed land will resemble its predisturbance state is an open question. The reclamation of wetlands, which cover two-thirds of the oil sands mineable area, is of particular concern. The re-creation of some types of wetlands, such as fens and bogs, is more challenging; and although research and large demonstration projects are under way, successful reclamation of these types

33. Overburden, or the material that overlies an oil sands deposit, consists typically of clay, sands, soils, and organic material including plants and vegetation.

34. The first oil sands mine commenced operations in 1967, producing 45,000 bd. Source: Suncor Energy, *www.suncor.com/en/about/744.aspx*, accessed 24 September 2013.

35. According to Alberta's Environmental Protection and Enhancement Act, before land can be certified as reclaimed it must have equivalent capability as its predevelopment state. For more information, see Alberta's Environmental Protection and Enhancement Act, 2000, *www.qp.alberta.ca/1266.cfm?page=E12.cfm&leg_type=Acts&isbncln=9780779735495*. For more information on land disturbances and reclamation, see Alberta ESRD, Oil Sands Portal, *http://environment.alberta.ca/apps/osip/*.

36. The maximum active mining footprint is expected to be reached in 2025, at 354 sq mi. See Figure 3 for more information.

of habitat remains an area of active research (see the section "Evolving policy and technology for land reclamation" below).

Land disturbance and reclamation: In situ

Compared with mines, in-situ operations disturb less land. Overburden is largely left in place, with only forest and vegetation removed for well pads, processing areas, and access corridors. This impacts about 7–15% of an in-situ lease area.[37] Also, the disturbance of land in an in-situ development takes place over a shorter period since the life of a well is shorter than that of a mine. For example, Imperial Oil's Cold Lake in-situ operation has been active since 1985, and 19% of its disturbed land, principally access roads and retired well pads, has been reclaimed.[38]

For in-situ operations, the way in which land is disturbed can impact wildlife in an area greater than the physical footprint. In-situ operations create linear corridors through the forest where the trees and vegetation have been removed to support infrastructure such as roads, pipes, and seismic lines. These linear disturbances, though relatively small as a percentage of land disturbed, fragment forests, affecting wildlife in an area beyond the footprint of the development by altering the mobility and interaction of forest animals.

The woodland caribou, a species at risk in Canada, is particularly vulnerable to linear disturbances.[39] Their population is declining in Canada, including the five known herds within the oil sands regions. In 2012 a Canada-wide federal Recovery Strategy for Woodland Caribou was released. It confirmed that linear disturbances from industry (oil sands, forestry, and other industrial activity) contributed to the decline—disturbing the caribou's habitat and increasing contact with predators.[40]

In response to the federal recovery strategy, Alberta and other provincial governments must now develop action plans (e.g., regional recovery strategies), expected by the end of 2015. It is possible that the rules will require oil sands operators to reduce project footprints and set more aggressive reclamation targets (including reclaiming beyond oil sands lease areas, such as lands disturbed from prior industrial development from conventional oil and gas or forestry). This could also require the culling of wolves, the primary predator risk for caribou.

Evolving policy and technology for land reclamation

As part of LARP, Alberta is committed to developing new policies to push for more rapid reclamation and reduction of disturbances in the oil sands region. The land-use plan includes commitments to encourage better sharing of existing footprint, such as access roads, between industrial users, forestry stakeholders, and oil and gas companies.

Also, research is under way to better understand methods to reclaim land disturbed by oil sands activity. Canada's Oil Sands Innovation Alliance (COSIA), a group of oil sands producers formed in 2012, is studying ways to accelerate land reclamation from mines, including harder-to-construct habitats such as wetlands and muskeg (a type of peat-rich wetland). For example, as part of COSIA, Syncrude, a major oil sands producer, has constructed a 17 hectare fen, a type of wetland, on a former mined pit to study and demonstrate how to reclaim these more challenging types of ecosystems on a large scale. Suncor, another major oil sands

37. The land disturbance resulting from in-situ developments is generally—but not always—somewhat higher than for conventional oil developments.

38. Source: Imperial Oil, *www.imperialoil.ca/Canada-English/operations_sands_glance_land.aspx*, accessed 24 July 2013.

39. In Canada, a species is considered at risk when its population is declining and at risk of becoming endangered or non–self-sustaining.

40. According to the 2012 federal Recovery Strategy for Woodland Caribou, 62% to 85% of the caribou's habitat within the oil sands region has been disturbed from natural (fire) and industrial activity (forestry and oil and gas). For more information, see Recovery Strategy for the Woodland Caribou, *www.sararegistry.gc.ca/document/default_e.cfm?documentID=2253*, accessed 23 July 2013.

producer and a member of COSIA, is also undertaking a similar project to reclaim a fen.[41] COSIA is also maintaining and growing a seed bank to ensure that a variety of plant species native to the boreal forest are available for reclamation in the future.

Water use

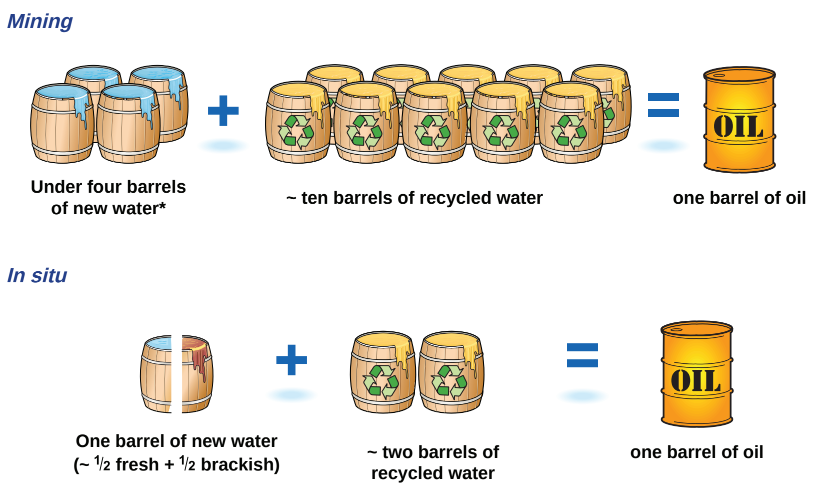
Water is used in oil sands extraction to separate the bitumen from the sand. In-situ operations get most of their water from underground sources, while the Athabasca River remains the main water source for mining operations. Water is critical to the local ecosystem—for local residents, wildlife, and fish habitat. And, without water, oil sands extraction could not take place. Anticipated growth in oil sands production has raised questions about the sustainability of future water demands. Although uncertainty exists, if new practices and technologies are deployed, water should not be a limiting factor in oil sands growth.

How does oil sands water intensity compare with other types of energy?

The water intensity of oil sands operations is comparable to other types of energy production. Oil sands extraction makes use of both "new" water that is withdrawn from the environment and recycled water. On a net basis, for each barrel of bitumen produced, an oil sands mining operation withdraws up to four barrels of new water from the environment, whereas an in-situ operation draws less than one barrel (see Figure 4).[42] An additional barrel of water is used per barrel of bitumen in refining and processing. This brings the total life-cycle water use to produce oil sands and convert them to useable refined products to around two barrels and five barrels per barrel of output for in-situ operations and mining, respectively. For comparison, life-cycle water use for refined products from conventional oil is one to three barrels of water per barrel of oil, and corn ethanol can require up to 550 barrels per barrel of oil equivalent.[43]

FIGURE 4

Oil sands extraction water intensity



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Note: Brackish water is defined as ground water with dissolved solids exceeding 4,000 milligrams per liter.

*Water demands do vary across oil sands mining operations. Industry wide, in 2012 mining operations used 3.15 barrels of "new" water per barrel of bitumen. And according to data from 2011, when all water sources are considered such as site runoff, river water withdrawals averaged 2.11 barrels per barrel of bitumen. Source: Alberta ESRD, Oil Sands Portal, *Oil Sands Operators: Water Use History,* http://environment.alberta.ca/apps/OSIPDL/Dataset/Details/56#. Athabasca river withdrawals provided directly by Alberta ESRD.

**Industrywide in-situ operations used on average 0.31 barrels of nonsaline groundwater and 0.25 barrels of brackish grounder water per barrel of bitumen produced. Source: Alberta ESRD, Oil Sands.

Source: IHS CERA and Alberta ESRD

What are the major sources of water?

For mining projects, the extraction process requires high-quality fresh water. The Athabasca River—the largest source of fresh water near the mining area—is the main source of water, providing about three of

41. For more information on Syncrude's and Suncor's wetland pilots, see *www.cosia.ca/projects/land/building-fens* and *www.suncor.com/en/newsroom/2418.aspx?id=1805639*, accessed 24 September 2013.

42. Comparison between water barrel and oil barrel is done on an equivalent volumetric basis, where one barrel is equivalent to 0.159 cubic meters.

43. Comparison is on a barrel of oil equivalent energy basis and a net water basis. Sources: Alberta ESRD and US Department of Energy, *Energy Demands on Water Resources: Report to Congress on the Interdependency of Energy and Water*, December 2006.

the four barrels of new water required per barrel of bitumen. The Athabasca River originates from the base of the Columbia Glacier in the Canadian Rockies, where it travels northeast through the oil sands region before terminating in Lake Athabasca in the northeast corner of Alberta. The remainder (about one barrel) comes from rain and other surface runoff that is collected from the mine lease area and some groundwater.

In-situ operations can use lower-quality water, and projects can be located farther from surface water sources. Accordingly, these projects use primarily groundwater. In 2012 nearly half of groundwater withdrawals to support in-situ production were of brackish water, with the remainder made up of higher quality nonsaline water.[44] Nonsaline groundwater may or may not be potable water, is typically found closer to the surface, and is higher quality than brackish sources. All brackish water is nonpotable water and is typically found beneath nonsaline water levels. Because of the depth where brackish water is found, withdrawals are less likely to have a direct impact on the water table and on surface water levels.

Water for mining operations (from the Athabasca River)

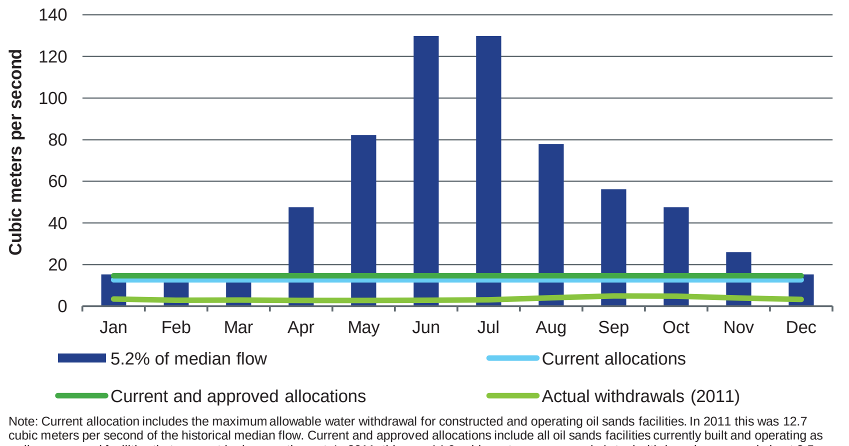
The Athabasca River is the second largest river in Alberta, and its watershed occupies nearly one-quarter of the province—an area of about 58,000 sq mi.[45] In 2011 oil sands mining operations withdrew 1.9 mbd (300,000 cubic meters per day) of water directly from the Athabasca River and an additional 640,000 barrels (102,000 cubic meters per day) from the surrounding environment.[46]

The Athabasca River flow fluctuates seasonally, with higher water levels in the summer and lower water levels in the winter. Water levels in the Athabasca River have been ample to support aquatic life and the wider ecosystem. Yet, given the level of growth expected from mining operations in the coming years, there are concerns that future withdrawals could impact the river's ecosystem, particularly in the winter months.

To protect the river during low-flow periods, the governments of Canada and Alberta have instituted a joint water-use framework. The first phase of this framework limits cumulative withdrawals from the river by oil sands operators to no more than 5.2% of the river's historical monthly median flow. These restrictions are shown in Figure 5—a graph of various withdrawal limits against 5.2% of the historical median flow of the Athabasca River. Current and approved oil sands water withdrawal licenses are near limits in the winter months; however, actual withdrawals have been much lower.[47]

FIGURE 5

Athabasca River flow: 5.2% of median flow compared to allocated withdrawals



Note: Current allocation includes the maximum allowable water withdrawal for constructed and operating oil sands facilities. In 2011 this was 12.7 cubic meters per second of the historical median flow. Current and approved allocations include all oil sands facilities currently built and operating as well as approved facilities that may not be in operation yet. In 2011, this was 14.6 cubic meters per second. Actual withdrawals averaged about 3.5 cubic meters per second in 2011.
Source: IHS CERA and Alberta ESRD, 2013 (2011 data)

44. Nonsaline water contains less than 4,000 milligrams (mg) per liter of total dissolved solids, whereas Health Canada defines potable water as containing less than 500 mg per liter of total dissolved solids. In brackish water, total dissolved solids exceed 4,000 mg per liter. For more information on in-situ water use, see Figure 3 footnotes.

45. Source: Athabasca Watershed Council, *www.awc-wpac.ca/content/athabasca-watershed*, accessed 31 July 2013.

46. Source: Athabasca River withdrawals provided by Alberta ESRD. Other water use data from Alberta ESRD Oil Sands Information Portal, *environment.alberta.ca/apps/OSIPDL/Browser#Category=WATER*, accessed 23 July 2013.

47. For more information see Figure 5 footnotes.

Outside of the official joint water-use framework, oil sands producers have implemented a private, nonbinding agreement to manage withdrawals from the Athabasca River during low-flow periods. The arrangement, the Oil Sands Water Management Agreement (OSWMA), currently includes the potential for further reductions—equivalent to less than 3% of the river's historical median flow during low-flow months.[48]

Looking ahead, there are concerns that the current restrictions may not be sufficient to protect the aquatic environment. A group of stakeholders, including representatives from government, industry, environmental groups, and First Nations, made recommendations for a second phase of the joint water-use framework that would reduce the cumulative water withdrawal limit.[49] This second phase of the framework was expected from regulators in 2012 but is yet to be released for public consultation prior to implementation.

Even under the most stringent restrictions, IHS CERA believes that—through the deployment of new technology and practices—water supply will be sufficient to support planned oil sands mining growth. If water withdrawals are more limited in the winter, there are alternatives. For example, new oil sands mining operations (and some older ones) have constructed large holding ponds that enable them to rely on stored water during low-flow winter months. Fluid tailings waste from mining operations is another potential water source. More rapid reclamation of liquid tailings (the potential of which is discussed in the waste section, below) would allow greater recycling of water within mining operations, reducing demands for new water.

Water for in-situ operations (groundwater)

The use of groundwater by in-situ oil sands projects will rise as bitumen output from these operations increases. Assuming no changes in in-situ water use, demand would nearly triple by 2030.[50] However, this outlook is not inevitable. There is potential for in-situ water intensity (particularly for nonsaline water) to decline as the industry moves toward greater use of brackish water sources.

- **Regulations that encourage in-situ projects to recycle more water and shift toward more brackish water sources**. Alberta recently introduced new regulations that will support greater recycling and encourage existing operations to shift toward more brackish water sources.[51] Brackish water sources in Alberta are believed to be immense, though less is known about them because they have had few historical uses and are typically present at greater depths. Importantly, use of brackish water does not compete with other water uses.

- **Potential use of tailings water and other recycled sources**. Although the applications are limited to in-situ operations near mining tailings ponds or local municipal waste systems, both could provide an additional source of recycled water that could reduce new water withdrawals. If more tailings from

48. Under certain low-flow conditions the OSWMA includes the potential for water withdrawal restrictions down to 8.2 cubic meters per second, versus 15 cubic meters per second under the existing framework. Fifteen cubic meters per second is equivalent to 5.2% of historical median flow during low-flow (winter) months. Source: Alberta ESRD, Oil Sands Information Portal, "Oil Sands Mining Management Agreement for 2012–2013 Winter Period," *environment.gov.ab.ca/info/library/8742.pdf*, accessed 16 July 2013.

49. Historical median flow of the Athabasca River during low-flow periods is about 300 cubic meters per second. Under the existing framework, withdrawals are restricted to 15 cubic meters per second when flows fall below 15% of the historical median flow (45 cubic meters per second). Under the recommended phase two framework, restriction could commence at 270 cubic meters per second, ratcheting down to 4.4 cubic meters per second when flow is below 87 cubic meters per second. Sources: Alberta ESRD, and the Cumulative Environmental Management Association (CEMA), *cemaonline.ca/index.php/administration/cat_view/2-communications/44-p2wmf*, accessed 14 October 2013.

50. Forecast groundwater demand growth assumes no new regulations or intensity improvements with a fixed water intensity based on 2012 oil sands production and water withdrawals. Under these restrictive assumptions, annual demand for new (brackish and nonsaline) would grow from 32.6 million cubic meters in 2012 to 93 million cubic meters in 2030. Note that there can be a larger variation in water intensity between projects owing to geology and hydrology. Source of withdrawals: Alberta ESRD. *Oil Sands Operators: Water Use History, All in-situ and integrated in-situ,* http://environment.ca/apps/OSIPDL/Dataset/Details/56, accessed 18 October 2013.

51. Alberta Energy Regulator (2012), Directive 081 - Water Disposal Limits and Reporting Requirements for Thermal In-Situ Oil Sands Schemes, November 21, 2012, *www.aer.ca/rules-and-regulations/directives/directive-081*, accessed 16 July 2013.

mining operations are reclaimed, this could be a large source of water for in-situ projects. Suncor is already making use of water from tailings ponds to augment water demands at one of its in-situ facilities.[52] Some in-situ project operators are also considering the use of municipal wastewater streams.

- **Development of new, less water-intensive in-situ techniques**. New in-situ extraction and water treatment technologies could reduce the demand for new water by further reducing water intensity and improving recycle rates. For instance, increased use of solvents in place of water improves water intensity. Broader deployment of technology, such as combining evaporators with zero liquid discharge processes, could further reduce water intensity by 80% to 100% compared with the traditional technology.[53]

The LARP, discussed in Part 3, will set forth cumulative interim triggers and limits for groundwater quality in the oil sands areas. To support these future requirements, Alberta is conducting a survey of nonsaline groundwater. These efforts will help ensure that industry demand are sustainable.

Waste (tailings)

Fluid waste material produced from oil sands mining operations, known as tailings, can be hazardous to the environment. While in-situ operations also generate waste, this is less of a concern than the tailings generated by mining operations. Ever since mining operations began, tailings material has been accumulating. Below we explore how tailings material could impact the environment and what is being done to manage further accumulations.

What are tailings, and how could they impact the environment?

Tailings are stored in large open-air settling basins, called tailings ponds. The ponds contain three layers: a top layer of water with some residual bitumen; a middle layer of fluid fine tailings (a combination of clay, silt, and water that does not readily settle); and a bottom layer of coarse sand.[54] Even after years of settling, the middle or fluid fine tailings layer does not settle and is the consistency of pudding. Historically for every barrel of bitumen produced at a mine, about four barrels of tailings were produced that had to be stored on site, with about 1 to 1.5 barrels being fluid fine tailings.[55] As oil sands production has grown, so has the accumulation of tailings. At the end of 2011, tailings ponds contained almost 5.7 billion barrels (900 million cubic meters) of material and covered a collective area about 78 sq mi (200 sq km) or about the size of the District of Columbia.[56]

There are two main environmental concerns about tailings growth: impacts on wildlife, specifically waterfowl if they contact tailings; and impacts if liquid tailings material escapes into the surrounding environment:

- **Impact on waterfowl**. Even though bitumen is periodically skimmed off the surface of tailings ponds, it can nonetheless accumulate (mostly along the edges of the ponds). If waterfowl land on the ponds and come in contact with bitumen, they can become soiled, which can lead to hypothermia or drowning. Although most landings (more than 99%) result in no measurable health impact on the birds, mortalities

52. Suncor Energy Inc., sustainability.suncor.com/2011/en/responsible/1799.aspx, accessed 23 July 2013.

53. See the IHS CERA Special Report *Oil Sands Technology: Past, Present, and Future*.

54. Fluid tailings contain about 1% to 3% bitumen by weight.

55. Fluid fine tailings estimate assumes 30% solids per barrel of bitumen produced and can vary with specific composition of oil sands ore, which can vary across deposits—some have more or less bitumen or fine content.

56. Source: Alberta ESRD. The tailings pond areas are contained within the total area disturbed to date shown in Figure 2.

occur, as was the case in 2008, when 1,600 ducks died, and in 2010, when 230 ducks died.[57] The best strategy is therefore to prevent contact. Since 1999 all mines have been required to have a Waterfowl Protection Plan that includes deterrents, such as air cannons, scarecrows, and flares. In addition, after the 2008 incident the federal and Alberta provincial governments initiated a regional bird monitoring program, and the fines levied against the industry for the death of birds in 2008 was used to finance further research at the University of Alberta. Research at the university and elsewhere is expanding the understanding and techniques of waterfowl protection in the oil sands regions.[58] For example, radar detection systems are being deployed that are expected to improve the effectiveness of bird deterrents.[59]

- **Impacts to the surrounding environment**. Water deposited in the tailings ponds has been found to be toxic to fish and other microorganisms. Although the toxicity of these ponds will decline over time as the organic compounds degrade, this is a slow process. For these reasons the Alberta government does not permit the release of tailings material. Since tailings ponds are unlined earthen structures, there are concerns about seepage of tailings material into the environment. In an effort to prevent this, tailings ponds are generally constructed above grade, above the surrounding land, with secondary containment structures and drains and ditches to collect seepage and surface runoff.[60] Clays found at the bottom of tailings ponds have low hydraulic conductivity and do not easily allow water to pass through, minimizing groundwater seepage. Despite these measures, some water seeps through into the environment. Measuring seepage is difficult, and there are no publicly available data that quantify the volume. Alberta ESRD monitors groundwater quality in the oil sands mining region, requiring each operator to provide an annual groundwater monitoring report. And, according to the "Latest Data" from the Canada-Alberta Oil Sands Environmental Monitoring Information Portal, "low levels of oil sands development-related contaminants" have been found in the water, but "are not a cause of concern."[61] The joint Canada-Alberta monitoring program, discussed in Part 3, will increase the scale and scope of water monitoring (ground and surface) in these areas.[62]

What is being done to address tailings growth and the existing stock of tailings?

In 2009, the Alberta regulator introduced Directive 74 to slow the accumulation of tailings material after 2010.[63] Although oil sands operators have invested more than C$1 billion in technology to reduce tailings, they did not meet the timeline set by the regulator.[64] Based on our analysis of the development plans outlined by operators, IHS CERA expects the accumulation of tailings to reach around 6.3 billion barrels (1 billion cubic meters) in the next few years (see Figure 6). If further mining operations proceed, the tailings volume could climb higher in the absence of new tailings management regulations. However, if the targets

57. Observed landings from April to October on about 10% of the ponds recorded 20,540 landings and found 139 dead birds. Source: News article in July 12, 2013 issue of the Edmonton Journal, *www.edmontonjournal.com/business/energy-resources/cannons+scaring+birds+away+from+tailings/8649164/story.html?__lsa=afac-1b0f*, accessed 19 July 2013. Source of 2008 bird incident: Reuters (2010), "UPDATE 2-Syncrude Canada fined C$3 [million] for 1,600 duck deaths," *www.reuters.com/article/2010/10/22/syncrude-ducks-idUSN2219038320101022*, accessed July 15, 2013. Source for 2010 bird incident: Reuters (2010), "At least 230 ducks die in latest Syncrude incident," *www.reuters.com/article/2010/10/27/us-syncrude-ducks-idUSTRE69L4K620101027*, accessed July 15, 2013.

58. For more information on the Research on Avian Protection Program at the University of Alberta or the Regional Bird Monitoring Program, see *hocking.biology.ualberta.ca/oilsands/?Page=8524*, accessed 14 October 2013.

59. For more information, see Nohara, T. J., Beason, R. C., and Clifford. S. P., (2012), "The Role of Radar-Activated Waterfowl Deterrents on Tailings Ponds," Presented at the International Oil Sands Tailings Conference, Edmonton, Alberta, December 2012, *www.accipiterradar.com/media/pdf/20120913_Iostc_Noharabeasoncliffordfinal_Distrib_.pdf*, accessed 16 September 2013.

60. Some tailings are stored below grade in mined-out pits.

61. Joint Oil Sands Monitoring, Latest Data, October 10, 2013, www.jointoilsandsmonitoring.ca/pages/latestdata.aspx?lang=en, accessed 15 October 2013.

62. For more information, see Canada-Alberta Oil Sands Environmental Monitoring Information Portal, *www.jointoilsandsmonitoring.ca/pages/home.aspx?lang=en*, accessed 23 July 2013.

63. For more information on Alberta Energy Regulator (formerly ERCB) Directive 74, see http://www.aer.ca/rules-and-regulations/directives/directive-074, accessed 14 October 2013.

64. The regulator in Alberta recently reviewed oil sands tailings performance and determined that although the pace of progress was slower than hoped, the target was "optimistic" and "industry had committed significant resources" toward the issue and "made material progress." Sources: Alberta Energy Regulator (2012), "2012 Tailings Management Assessment Report: Oil Sands Mining Industry," *www.aer.ca/documents/oilsands/tailings-plans/tailingsmanagementassessmentreport2011-2012.pdf*, accessed 16 July 2013; Oil Sands Today (CAPP website), *www.oilsandstoday.ca/topics/Tailings/Pages/default.aspx*, accessed 16 July 2013.

are reached, tailings would be processed as the same rate as they are produced, and fluid fine tailings would no longer accumulate.

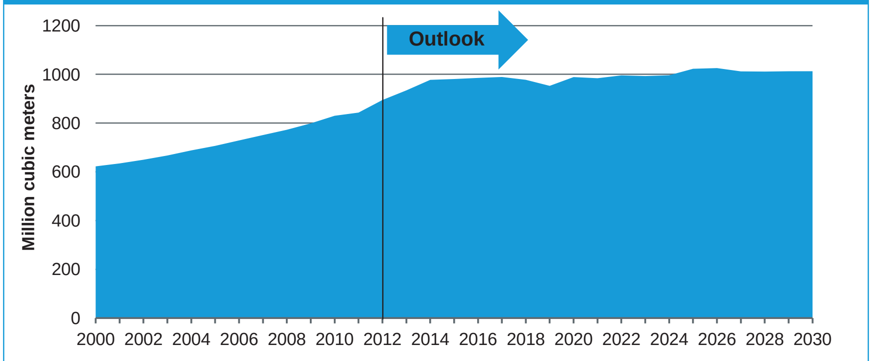
In addition to reducing the rate of accumulation, there is additional focus on reducing the existing tailings inventory. Alberta has committed to reducing legacy tailings material and has promised a new tailings management plan.[65] It will be challenging for the industry to dispose of the tailings. Separating the water from some of the fine clays in the tailings is difficult. Two general methods for disposal are being developed:

- **Liberating water from the tailings**. One disposal method is to allow the tailings to dry out. Areas where tailings have been dried could then support revegetation and reclamation. Tailings do not readily dry out on their own, however, and industry, government, and academia are collaborating on the advancement of technologies to accelerate the separation of water and the drying of tailings.[66] Some leading technologies are centrifuge, atmospheric fines drying, accelerated dewatering, and soft tailings reclamation.[67]

- **Permanently storing the tailings**. Another disposal method is to store the tailings beneath a fresh water cap in end pit lakes (EPLs). The fresh water acts as a barrier between the tailings material beneath and the environment above. Although capping tailings with fresh water has been used in other types of mining operations for decades, in the oil sands it remains unproven. There is concern about whether these lakes can become active ecosystems that support plant and animal life. If unsuccessful they could pose a long-term liability for the province. Before the government permits the use of EPLs, the industry must demonstrate to the satisfaction of regulators that they are a viable option. To this end, Syncrude Canada has been running test ponds since 1989 and is now scaling up this research to a large-scale demonstration project. Although efforts are increasing, it could still be decades before the results will be fully known.[68]

FIGURE 6

IHS CERA estimate of cumulative fine fluid tailings inventory



Based on the tailings plans of operators. Does not include the following potential projects: Total E&P Joslyn North or South Mine; Shell Albian Sands Pierre River Mine; Suncor Energy Voyageur South Expansion, Teck Frontier Mine, and Total/Sinopec, Northern Lights Project. Mines plans included: Horizon Tailings Management Plan, November 2010. Suncor Energy 2011 Mine & Tailings Plan Millenium, North Steepbank Extension and Lease 86/17, ERCB Annual Submission, September 2010. Syncrude Annual Tailings Plan Submission Mildred Lake, September 2010. Syncrude Annual Tailings Plan Submission Aurora North, September 2010. Syncrude Annual Tailings Plan Submission Aurora South, September 2010 with a delay from 2016 start to 2021 based on news from Syncrude that project postponed to post 2020. Shell Canada Energy Muskeg River Mine Annual Tailings Management Plan 2011. Shell Albian Sands – Jackpine Mine ERCB Directive 074 Jackpine Mine Tailings Management Plan, December 2010. Imperial Kearl Oil Sands 2010 Annual Tailings Plan Submission to ERCB, September 2010. Fort Hills Energy ERCB Directive 074 Annual Tailings Management Plan, September 2009.
Source: IHS CERA

65. Source of tailings management framework: Lower Athabasca Regional Plan, Tailings Management Framework, *https://landuse.alberta.ca/RegionalPlans/LowerAthabascaRegion/Pages/default.aspx*, accessed 1 August 2013.

66. For more information on this collaboration, see *www.cosia.ca/releases/3/158/Tailings-Technology-Roadmap-project-invokes-major-industry-government-collaboration/d,detail_interior*.

67. For more information, see www.cosia.ca/projects/tailings/tailings-technology-roadmap, accessed 14 October 2013.

68. Source: Syncrude Sustainability Report 2010/11, www.syncrudesustainability.com/2011/environment#operational_environment_tailings-management, accessed 17 September 2013.

Part 5: Greenhouse gas emissions

GHG emissions linked to oil sands production are a contentious—and high-profile—issue. This section examines the GHG intensity of oil sands compared with other crudes, the aggregate emissions from the industry as a whole, and the state of GHG regulation in the oil sands. It also presents a snapshot of the current state of play and explains how the GHG intensity of oil sands production is expected to decline through the deployment of new technology. The potential impact of the new technology is discussed in Part 6.

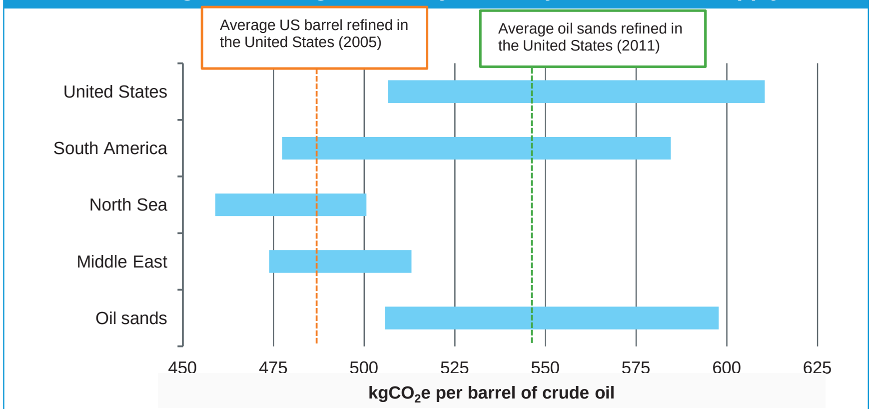
Why does the GHG intensity of oil sands matter?

Government policy that makes use of crude oil GHG intensities could affect demand for different crudes. Low carbon fuels standards (LCFS) being advanced in British Columbia, California, and the European Union seek to reduce GHG emissions from the entire life cycle of a fuel used within their jurisdiction. This includes GHG emissions from production, processing, transportation, and finally combustion. When LCFS policies differentiate crudes by GHG intensity, oil sands along with other higher carbon crudes can be disadvantaged.

Although oil sands are among the more GHG-intensive crudes, they are not the most intensive—nor are they as high carbon as many commonly cited estimates. On a wells-to-wheels basis—accounting for emissions produced during crude oil extraction, processing, distribution, and combustion, including from upstream fuel consumed in crude production and processing facilities—the GHG emissions from oil sands are 4% to 23% higher than from the average crude consumed in the United States, using a 2005 baseline. For the average oil sands product actually exported to the United States, life-cycle GHG emissions are only 12% higher. As shown in Figure 7, sources of supply from other oil-producing regions are in the same range as oil sands.[69] For example, the GHG emissions of Venezuelan crude, the most likely alternative to oil sands in the USGC, are in the same range as oil sands (4–20% higher than the average crude refined in the United States).[70]

FIGURE 7

Well-to-wheels greenhouse gas intensity from major areas of US supply



Note: Based on wide-boundary results in the IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Supply: Getting the Numbers Right—2012 Update.*
Crude ranges based specifically on United States: Mars to Midway-Sunset; South America: Brazil Tupi to Venezuela Petrozuata; North Sea: Statfjord to Mariner; Middle East: Arab Medium to Basra Light; and oil sands: mining dilbit to SAGD SCO.
Source: IHS CERA

69. For more information, see the IHS CERA Special Report *Oil Sands Dialogue: Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right—2012 Update*.

70. Venezuela produces a number of crude oil blends that are imported into the Unites States. Similar to oil sands, the GHG intensity of Venezuelan crudes differs depending on the specific blend. For example our estimate of the GHG intensity of Bachaquero, a conventional Venezuelan heavy crude, is 4% higher than the average crude refined in the United States. However, if Venezuela were to grow production it would mostly likely come from the Orinoco belt. We estimate that the GHG intensities for upgraded Orinoco production, Petrozuata and Zuata Sweet, are 20% and 15% higher, respectively. For more information on alternative crudes oil to Canadian oil sands in the USGC, see the IHS CERA Insight *Keystone XL Pipeline: No material impact on US GHG emissions*.

Measuring the life-cycle GHG emissions of fuels is complex. Data quality and availability are often a key challenge—making estimates of crude oil emissions less certain. In a 2011 report, IHS CERA compared the availability of environmental data from eight existing and potential future crude oil suppliers to the United States: Canada, Mexico, Saudi Arabia, Nigeria, Venezuela, Iraq, Brazil, and Kazakhstan. We found that of all the jurisdictions compared, the Canadian oil sands have the highest level of readily available online data.[71] Since Canada provides more data than most other crude suppliers, there is a risk that oil sands could be unfairly disadvantaged compared with other supply sources.

Aggregate GHG emissions: Current and outlook

Aggregate oil sands emissions are growing alongside production growth. In 2011 oil sands operations emitted 55 million metric tons (MMt) of carbon dioxide equivalent (CO_2e) per year—7.8% of Canada's total GHG emissions and 0.14% of global emissions.[72] This is on a similar scale as the level of emissions from power generation from the states of Louisiana or Arizona in 2011.[73] Assuming that no new climate change policies are implemented in Canada, Environment Canada estimates oil sands emissions could reach 104 MMtCO_2e per year by 2020. This could make oil sands responsible for 14% of Canada's total emissions.[74]

GHG Regulations

Oil sands GHG emissions are regulated at the provincial level. Since 2007 oil sands facilities and other large emitters in Alberta have been required to reduce emissions intensity by 2% per year, ramping up to 12% below an average intensity baseline established over the first three years of operation, or from 2003 to 2005 for existing facilities.[75] To comply, operators have the option of reducing emissions, investing in offsets, or paying a carbon levy of C$15 per ton for every ton of GHG emissions produced above the limit. Since 2007, over C$300 million has been collected by the provincial government from the carbon levy. These funds are reinvested in projects geared toward reducing GHG emissions.[76] In total, Alberta estimates that operational changes and investment in offsets as a result of their program have contributed to 40 MMt in GHG reductions from 2007 to 2012.[77]

The federal government is developing additional regulations. At the UN Climate Change Conference in Copenhagen in 2009, Canada committed to reducing its total GHG emissions by 17% from 2005 levels by 2020—the same objective as the United States. To meet this goal Canada is adopting a sector-by-sector approach to GHG reductions.[78] In 2012 Canada finalized regulations for the coal-fired power generation sector and is now developing regulations for the oil and gas sector, including for the oil sands.

71. See the IHS CERA Special Report *Major Sources of US Oil Supply: The Challenge of Comparisons*.

72. Estimate of global share of emissions based on oil sands' share of Canadian emissions on a CO_2 equivalent basis in 2011 and Canada's share of global emissions on a CO_2 basis from combustion in 2010. Source: Environment Canada (2013), *National Inventory Report 1990–2011*, 15 April 2013, *unfcc.int/national_reports/annex_i_ghg_inventories_submissions/items/7383.php*, accessed 16 July 2013; Source: International Energy Agency (2012), CO2 *Emissions from Fuel Combustion Highlights*, *www.iea.org/co2highlights/co2highlights.pdf*, accessed 16 September 2013.

73. Source: 2011 US Environmental Protection Agency, *Greenhouse Gas Emissions from Large Facilities*, *http://ghgdata.epa.gov/ghgp*, accessed 16 September 2013.

74. Source: Environment Canada (2012), *Canada's Emissions Trends*, August 2012.

75. In 2007 the Specified Gas Emitters Regulation came into force in Alberta. It covers large stationary sources of GHG emissions, such as power plants, oil and gas facilities, and refineries that emit more than 100,000 metric tons of GHG per year. For more information, see *www.environment.alberta.ca/01838.html*, accessed 14 October 2013.

76. For more information, see Alberta's Climate Change Strategy, *environment.alberta.ca/0909.html*, accessed 23 July 2013.

77. Source: Alberta ESRD, 2012 Greenhouse Gas Emissions Reduction Program Results, *http://environment.alberta.ca/04220.html*, accessed 13 September 2013.

78. The Canadian approach also includes a number of energy efficiency measures, such a renewable fuels standards, light- and heavy-duty vehicle standards, and appliance standards.

Part 6: Technology

Technical innovation is at the heart of the Canadian oil sands story and is expected to bring about reductions in costs and the environmental intensity of oil sands production.

The deployment of new technology has made the oil sands an economic venture and at the same time has reduced its environmental footprint. (The average GHG intensity of oil sands production is 26% lower than it was in 1990.)[79] Collaboration is another perennial theme in oil sands development, playing a central role in past innovations, including in the development of SAGD. The original SAGD pilot project was conducted in 1984 by Alberta Oil Sands Technology and Research Authority (AOSTRA), a partnership between government and industry. Over AOSTRA's 25-year existence, industry and government have joined forces on 16 oil sands field trials; the SAGD pilot was the only trial that resulted in a commercial process.[80]

Accelerating innovation and collaboration

Technical innovation continues today, and a wide range of new approaches are under development. In fact, compared with the past, new ideas are being tested at an accelerated pace. Innovations being tested include new in-situ extraction methods (such as using hot or cold solvents, electric heating, or in-situ combustion to mobilize the bitumen) and methods to capture carbon from combustion exhaust streams. One project plans to convert carbon emissions from oil sands into biofuels. Many mining pilots aim to reduce water use and eliminate tailings waste. All together, the industry has plans for over 10 field pilots—more than half the pilots that AOSTRA's accomplished in its 25-year existence. Although there is no certainty that the field pilots will lead to commercial technologies, with such a significant number of ideas being field tested—a critical step in technology development—the chances are greatly improved.

Collaboration is also accelerating. The formation of COSIA was announced in 2012, and as of mid-2013, 14 major oil sands companies had come together to share environmental research, technology, and best practices.

COSIA is arguably the most extensive example of industry collaboration to date. Companies are putting aside their competitive cultures and intellectual property when it comes to environmental technology. There is a shared realization that only by accelerating the development and deployment of environmental improvements are material changes in oil sands operations likely to result. The breadth of COSIA's mandate is wide, and the challenge is great—effectively to enable responsible and sustainable development of the Canadian oil sands. It is focused on four main environmental challenges, all of which we document in this report: tailings management and reduction, water use and improved recycling, reduction of land use and impact, and GHG reduction. Our research was unable to find other examples of collaboration on the scale of COSIA elsewhere in the oil and gas industry.[81]

The rapid sharing of ideas is a clear advantage of the COSIA model. If green techniques are deployed at one oil sands operation, the innovation has little impact on the aggregate environmental footprint of the industry. Only when technologies are applied widely, across a greater volume of production, are material impacts possible. COSIA has the potential to speed up the industrywide deployment of new ideas. The ultimate success of COSIA will take many years to measure, since advancements in oil sands technology are most often measured in decades, not years. However, COSIA's initiatives, combined with numerous other industry collaborations, constitute a major step toward reducing the environmental intensity of oil sands production.

79. Source: Environment Canada, May 2013 National GHG Inventory Report 1990–2011.

80. In 2000 what was AOSTRA became part of Alberta Innovates—Energy and Environmental Solutions.

81. For more information, see *www.cosia.ca*.

Potential for reducing the environmental intensity of oil sands

Over the next decade, the greatest opportunity for oil sands GHG emissions reductions is through adding solvents to the steam used for in-situ recovery—a technique called hybrid steam-solvent extraction. If the technique can be made economic, it could reduce GHG production emissions by 25% or more and lower water use by an even greater margin. Since this technique can be applied to existing facilities, it could have a material impact on aggregate emissions from the industry.

For the more mature mining operations, although some options exist for GHG improvements, such as lower-temperature water extraction methods, compared with in-situ operations there is less potential for a material change in GHG emissions. However, assuming that technologies to dry tailings are developed, there are significant opportunities to reduce water withdrawals. Given the Alberta and Canadian governments' significant investment, we expect at least one oil sands–related carbon capture and storage (CCS) project to be operational within the decade. The project will capture emissions from the oil sands upgrader, reducing the GHG intensity from producing SCO from mining by about 20% compared with current levels.[82]

Longer term, the development of totally new extraction methods could lead to greater reductions in environmental intensity, but these trends are not inevitable. Even when ideas are found to be commercially viable, the time lag between a successful pilot and broad commercial deployment is typically more than a decade. Further, most completely novel extraction methods can be applied only to new facilities. Consequently, it can take decades before production from these new ideas becomes large enough to have a material impact on the environmental intensity of the industry as a whole.

82. The Quest CCS project is under way at the Scotford Upgrader in Edmonton. The Alberta government is investing C$745 million (from a C$2 billion fund for CCS), and the Government of Canada is investing C$120 million (from the Clean Energy Fund). The project is expected to reduce upgrading emissions by 35%. IHS CERA has estimated that this equates to about a 20% combined reduction from mining and upgrading. For more information, see *www.shell.ca/en/aboutshell/our-business-tpkg/upstream/oil-sands/quest.html*. There is another project with the potential to capture and store CO_2 related to oil sands being advanced in Alberta. The North West Upgrader, a refinery planned near Edmonton, will include CO_2 capture for use in enhanced oil recovery as well as storage. For more information, see *www.northwestupgrading.com*, accessed 14 October 2013.

Part 7: Pipeline transport of oil sands

Concern has been expressed that pipelines transporting oil sands crude, specifically diluted bitumen, may be more at risk for spills than those transporting conventional crudes. However, pipeline corrosion is a well understood phenomenon, and a number of scientific studies have found no evidence that oil sands crudes subject pipelines to greater risk of damage or spills than other crudes.[83]

It has been suggested that the characteristics of oil sands crudes, which can have a relatively high total acid number (TAN) and sulfur content, make them more likely than other crudes to corrode pipelines. However, the properties of oil sands crudes have been found to be within the range of other crudes transported by pipeline in North America. Moreover, although these two measures of crude quality are important corrosion indicators under refinery conditions (higher temperatures, higher velocity, and smaller pipes), they are of little relevance under transportation pipeline conditions (lower temperature, lower velocity, and larger pipes). For corrosion to occur in transmission pipelines, water along with a corrosive agent, such as sulfides, must be present and be in sustained contact with the pipeline surface. Yet impurities, such as moisture, sediment, and other chemicals that are known to contribute to corrosion, are tightly controlled in pipeline operations.[84]

The velocity and temperature of crude oil moving in the pipeline are other important factors in preventing pipeline corrosion. Water can separate from crude oil if the velocity of crude oil through a pipeline is insufficient. Pipelines that carry heavy crudes (including diluted bitumen) are operated at rates that prevent water accumulation. Moreover, even if water accumulates for any reason (e.g., an upset in pipeline operations that slows flows), when the crude velocity is restored, water would be reabsorbed.

It has also been suggested that pipelines transmitting oil sands crude can operate at higher temperatures, potentially contributing to pipeline metal fatigue. However, studies have shown that pipelines carrying diluted bitumen typically operate at less than 50° Celsius (C), well below temperatures of concern—over 200°C—and within the range of other pipelines.[85]

83. Sources: Been, J. (2011), “Comparison of the Corrosivity of Dilbit and Conventional Crude,” prepared for Alberta Innovates-Technology Futures, September 2011, *http://ai-ees.ca/media/6860/1919_corrosivity_of_dilbit_vs_conventional_crude-nov28-11_rev1.pdf*, accessed 22 July 2013. Papavinasam, S., Rahimi, P., Williamson, S. “Corrosion Conditions in the Path of Bitumen from Well to Wheels,” NACE 2012 Northern Area Eastern Conference, Toronto, Canada, October 28–31, 2012, *http://www.nrcan.gc.ca/minerals-metals/materials-technology/4542*, accessed 22 July 2012. Penspen (2013), “State of the Art Report: Dilbit Corrosivity,” Commissioned for Canadian Energy Pipeline Association, February 21, 2013, Document No. 12671RPT-001 REV 1 *http://www.cepa.com/wp-content/uploads/2013/02/FINAL-Penspen-Report-Dilbit_Corrosivity_Final.pdf*, accessed 22 July 2013. The National Research Council (2013), “TRB Special Report 311: Effects of Diluted Bitumen on Crude Oil Transmission Pipelines,” Washington, DC: The National Academies Press, 2013, *http://www.nap.edu/catalog.php?record_id=18381*, accessed 22 July 2013.

84. Basic sediments, salts, and water are tightly controlled and limited to less than 0.5% on a mass-to-volume basis.

85. Organic acids, as measured by TAN, can be a concern under refinery temperatures above 200°C. For more information see prior footnote with reference to studies.

Conclusion

For a number of important issues related to oil sands development, a wide spectrum of views exists. These differences are at the heart of the debate over the future of oil sands development and market access. Since we issued our first Special Report on the oil sands in 2009, the heightened level of scrutiny of the oil sands—by environmental nongovernmental organizations, media, academia, governments, and the general public—has contributed to an evolution in government regulation and oversight, as well as industry collaboration.

Key areas of changes are

- **Regulation**. The federal and provincial governments in Canada are implementing a more cumulative approach to oil sands development, establishing regional environmental thresholds.
- **Oversight**. Governments are moving to expand and strengthen monitoring activities, putting more equipment and people on the ground to monitor activities and make data more accessible to the public.
- **Collaborative technology development**. Industry initiatives such as COSIA are encouraging faster technology development by pooling resources and sharing learning, and more pilot programs than ever are now under way. Historically, research has been focused on the economics of extracting oil sands; but today there is a greater focus on the environmental footprint.

These changes are providing greater clarity to some key environmental questions, such as the sustainability of water use; the end of tailings accumulation; and the future of regional air quality. But questions remain. For instance, for mining operations: What will reclaimed land look like? And for in-situ operations: How will industry work to protect key wildlife habitats?

The future of oil sands development is of great importance to Canada and beyond, since it impacts both North American oil security and global crude supply. The far-reaching dialogue surrounding oil sands is shaping future development and helping the industry and government to strike the appropriate balance between meeting economic and security objectives and safeguarding the environment.

Report participants and reviewers

On 13 November 2012, IHS CERA hosted a focus group meeting in Washington, DC, to providing an opportunity for oil sands stakeholders to convene and discuss perspectives on the critical questions shaping oil sands development. A number of those participants also reviewed a draft version of this report.

Participation in the focus group or in the review of the draft report does not reflect endorsement of the content of this report. IHS CERA is exclusively responsible for the content of this report.

Alberta Department of Energy

Alberta Environment and Sustainable Resource Development

Alberta Innovates, Energy and Environmental Solutions

American Petroleum Institute

BP Canada

Canadian Association of Petroleum Producers

Canadian Oil Sands Limited

Cenovus Energy Inc.

Devon Energy Corporation

Enbridge Inc.

Conoco Philips Company

Canadian Natural Resources Ltd.

Imperial Oil Ltd.

In Situ Oil Sands Alliance

Marathon Oil Corporation

Natural Resources Canada

Nexen Inc.

Pembina Institute

Shell Canada

Statoil Canada Ltd.

Suncor Energy Inc.

Total E&P Canada Ltd.

TransCanada Corporation

IHS team

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