Technological Prospects for Reducing the Environmental Footprint of Canadian Oil Sands

The Expert Panel on the Potential for New and Emerging Technologies to Reduce the Environmental Impacts of Oil Sands Development

Council of Canadian Academies
Conseil des académies canadiennes

Science Advice in the Public Interest

TECHNOLOGICAL PROSPECTS FOR REDUCING THE ENVIRONMENTAL FOOTPRINT OF CANADIAN OIL SANDS

The Expert Panel on the Potential for New and Emerging Technologies to Reduce the Environmental Impacts of Oil Sands Development

THE COUNCIL OF CANADIAN ACADEMIES
180 Elgin Street, Suite 1401, Ottawa, ON, Canada K2P 2K3

Notice: The project that is the subject of this report was undertaken with the approval of the Board of Governors of the Council of Canadian Academies. Board members are drawn from the Royal Society of Canada (RSC), the Canadian Academy of Engineering (CAE), and the Canadian Academy of Health Sciences (CAHS), as well as from the general public. The members of the expert panel responsible for the report were selected by the Council for their special competencies and with regard for appropriate balance.

This report was prepared for the Government of Canada in response to a request from the Minister of Natural Resources. Any opinions, findings, or conclusions expressed in this publication are those of the authors, the Expert Panel on the Potential for New and Emerging Technologies to Reduce the Environmental Impacts of Oil Sands Development, and do not necessarily represent the views of their organizations of affiliation or employment.

Library and Archives Canada Cataloguing in Publication

Technological prospects for reducing the environmental footprint of Canadian oil sands: the Expert Panel on the Potential for New and Emerging Technologies to Reduce the Environmental Impacts of Oil Sands Development/Council of Canadian Academies.

Includes bibliographical references.

Electronic monograph in PDF format.

ISBN 978-1-926522-11-1 (pdf)

Cover image: Landsat imagery courtesy of NASA Goddard Space Flight Center and U.S. Geological Survey

1. Oil sands—Environmental aspects—Alberta. 2. Oil sands industry—Technological innovations—Alberta. 3. Environmental impact analysis—Alberta. 4. Green technology—Alberta. I. Council of Canadian Academies, issuing body II. Council of Canadian Academies. Expert Panel on the Potential for New and Emerging Technologies to Reduce the Environmental Impacts of Oil Sands Development, author

TD195.P4T42 2015 333.8'232097123 C2015-902597-4

This report can be cited as: Council of Canadian Academies, 2015. *Technological Prospects for Reducing the Environmental Footprint of Canadian Oil Sands.* The Expert Panel on the Potential for New and Emerging Technologies to Reduce the Environmental Impacts of Oil Sands Development, Council of Canadian Academies.

Printed in Ottawa, Canada

Council of Canadian Academies
Conseil des académies canadiennes

Canada

This assessment was made possible with the support of the Government of Canada.

The Council of Canadian Academies
Science Advice in the Public Interest

The Council of Canadian Academies is an independent, not-for-profit corporation that supports independent, science-based, authoritative, expert assessments to inform public policy development in Canada. Led by a 12-member Board of Governors and advised by a 16-member Scientific Advisory Committee, the Council's work encompasses a broad definition of *science*, incorporating the natural, social, and health sciences as well as engineering and the humanities.

Council assessments are conducted by independent, multidisciplinary panels of experts from across Canada and abroad. Assessments strive to identify emerging issues, gaps in knowledge, Canadian strengths, and international trends and practices. Upon completion, assessments provide government decision-makers, researchers, and stakeholders with high-quality information required to develop informed and innovative public policy.

All Council assessments undergo a formal report review and are published and made available to the public free of charge in English and French. Assessments can be referred to the Council by foundations, non-governmental organizations, the private sector, or any level of government.

The Council is also supported by its three founding Member Academies:

The Royal Society of Canada (RSC) is the senior national body of distinguished Canadian scholars, artists, and scientists. The primary objective of the RSC is to promote learning and research in the arts and sciences. The RSC consists of nearly 2,000 Fellows — men and women who are selected by their peers for outstanding contributions to the natural and social sciences, the arts, and the humanities. The RSC exists to recognize academic excellence, to advise governments and organizations, and to promote Canadian culture.

The Canadian Academy of Engineering (CAE) is the national institution through which Canada's most distinguished and experienced engineers provide strategic advice on matters of critical importance to Canada. The Academy is an independent, self-governing, and non-profit organization established in 1987. Fellows are nominated and elected by their peers in recognition of their distinguished achievements and career-long service to the engineering profession. Fellows of the Academy, who number approximately 600, are committed to ensuring that Canada's engineering expertise is applied to the benefit of all Canadians.

The Canadian Academy of Health Sciences (CAHS) recognizes individuals of great achievement in the academic health sciences in Canada. Founded in 2004, CAHS has approximately 400 Fellows and appoints new Fellows on an annual basis. The organization is managed by a voluntary Board of Directors and a Board Executive. The main function of CAHS is to provide timely, informed, and unbiased assessments of urgent issues affecting the health of Canadians. The Academy also monitors global health-related events to enhance Canada's state of readiness for the future, and provides a Canadian voice for health sciences internationally. CAHS provides a collective, authoritative, multidisciplinary voice on behalf of the health sciences community.

www.scienceadvice.ca
@scienceadvice

The Expert Panel on the Potential for New and Emerging Technologies to Reduce the Environmental Impacts of Oil Sands Development

Eric Newell, O.C., FCAE, A.O.E. (Co-Chair), Former CEO, Syncrude Canada Ltd; Chancellor Emeritus and Special Advisor to the Provost, University of Alberta (Edmonton, AB)

Scott Vaughan (Co-Chair), President and CEO, International Institute for Sustainable Development (Ottawa, ON)

Michel Aubertin, FCAE, Professor, Department of Civil, Geological and Mining Engineering, and Scientific Director, Research Institute on Mines and the Environment, École Polytechnique de Montréal (Montréal, QC)

Joule Bergerson, Assistant Professor, Department of Chemical and Petroleum Engineering, Schulich School of Engineering, University of Calgary (Calgary, AB)

Ian D. Gates, Professor and Head, Department of Chemical and Petroleum Engineering, University of Calgary (Calgary, AB)

Murray R. Gray, FCAE, Vice-President, Research, Hamad Bin Khalifa University (Doha, Qatar); Past Scientific Director, Institute for Oil Sands Innovation, University of Alberta (Edmonton, AB)

Jacob Masliyah, O.C., FRSC, FCAE, Distinguished University Professor Emeritus, University of Alberta (Edmonton, AB)

Gord McKenna, Senior Geotechnical Engineer, BGC Engineering Inc. (Vancouver, BC); Adjunct Professor, Department of Renewable Resources, University of Alberta (Edmonton, AB)

Jay Nagendran, President and Chief Executive Officer, Alberta Environmental Monitoring, Evaluation and Reporting Agency (AEMERA) (Edmonton, AB)

Paul Painter, President and Co-founder, IL Fuels LLC; Emeritus Professor, Polymer Science and Engineering, Pennsylvania State University (University Park, PA)

Janet Peace, Vice President, Markets and Business Strategy, Center for Climate and Energy Solutions (Arlington, VA)

Kevin Percy, Executive Director, Wood Buffalo Environmental Association (Fort McMurray, AB)

The Council also recognizes the contribution of Marlo Raynolds, Vice President, Market Development, BluEarth Renewables Inc. (Calgary, AB), to this assessment.

Message from the Co-Chairs

This Expert Panel came together in the context of a wider debate about the role of Canada's oil sands in a carbon-constrained world. A key question is whether proven and emerging technologies have the capability to significantly reduce the environmental footprint of the oil sands. That has been the charge of the Panel.

The oil sands have always been highly dependent on technology. Evaluating the extent to which existing and emerging technologies are capable of reducing the environmental footprint of all aspects of oil sands operations is a fundamental challenge.

However urgent this task, it is analytically challenging. Fundamental uncertainties temper our ability today to anticipate the future performance of emerging technologies, the future levels of ambition of carbon and other environmental policies, as well as the uncertainty inherent in forecasting the extent of technological innovation in an industry where investment priorities are strongly influenced by changing oil prices. What we do know today, however, is that a clear roadmap is needed to show how to reduce the environmental footprint of the oil sands.

By bringing together a wide range of expertise and evidence, the Panel believes that this report makes an important contribution in setting out what is known about the environmental footprint of the oil sands and the range of technological opportunities to reduce it, together with their associated risks and uncertainties. It hopes that this report will prove useful for government and industry alike as they make decisions on the best way forward.

As Chairs, we are indebted to our colleagues on the Panel who contributed their time, effort, and considerable expertise to ensure the breadth, depth, and overall quality of the report. Deliberations proved insightful and constructive for all involved.

On behalf of the Expert Panel, we thank Natural Resources Canada and Environment Canada for asking the Council to undertake this assessment, and the expert peer reviewers who set aside the time to critique the report and help ensure its comprehensiveness, accuracy, and balance. We would also like to thank the professionals at Cenovus, Syncrude, and Wood Buffalo Environmental Association for their informative and insightful tours of their facilities and Canada's Oil Sands Innovation Alliance for providing input to the Panel's deliberations. Finally, we are very grateful to the Council's project team for its outstanding research, rigour, and objectivity throughout the assessment.

Eric Newell, O.C., FCAE, A.O.E., Co-Chair

Scott Vaughan, Co-Chair

The Expert Panel on the Potential for New and Emerging Technologies to Reduce the Environmental Impacts of Oil Sands Development

Project Staff of the Council of Canadian Academies

Assessment Team:	Tijs Creutzberg, Program Director Joe Rowsell, Research Associate Stefan Jungcurt, Research Associate François Bregha, Consultant Cyril Adjeitey, Intern Kristen Cucan, Program Coordinator
With assistance from:	Clare Walker, Editor Accurate Design & Communication Inc., Report Design

Report Review

This report was reviewed in draft form by the individuals listed below — a group of reviewers selected by the Council of Canadian Academies for their diverse perspectives, areas of expertise, and broad representation of academic, industrial, policy, and non-governmental organizations. The reviewers assessed the objectivity and quality of the report. Their submissions — which will remain confidential — were considered in full by the Panel, and many of their suggestions were incorporated into the report. They were not asked to endorse the conclusions, nor did they see the final draft of the report before its release. Responsibility for the final content of this report rests entirely with the authoring Panel and the Council.

The Council wishes to thank the following individuals for their review of this report:

Amin Asadollahi, Oilsands Program Director, Pembina Institute (Calgary, AB)

S. Lee Barbour, FCAE, Professor, Department of Civil and Geological Engineering, University of Saskatchewan (Saskatoon, SK)

Richard Chalaturnyk, Professor of Geotechnical Engineering, Department of Civil and Environmental Engineering, University of Alberta (Edmonton, AB)

David W. Devenny, FCAE, President, The Rock Doctor (Calgary, AB)

Laura Diaz Anadon, Assistant Professor of Public Policy, Harvard Kennedy School (Cambridge, MA)

Andy Fourie, Professor, School of Civil, Environmental & Mining Engineering, University of Western Australia (Crawley, Australia)

Stephen Larter, Professor and Canada Research Chair in Petroleum Geology, University of Calgary (Calgary, AB)

William McCaffrey, Professor, Department of Chemical and Materials Engineering, University of Alberta (Edmonton, AB)

Randy Mikula, Research Scientist, KALIUM Research (Edmonton, AB)

M. Anne Naeth, Professor, Land Reclamation and Restoration Ecology, University of Alberta (Edmonton, AB)

David Schindler, O.C., FRSC, A.O.E., Killam Memorial Professor of Ecology (Emeritus), University of Alberta (Edmonton, AB)

The report review procedure was monitored on behalf of the Council's Board of Governors and Scientific Advisory Committee by **Murray S. Campbell**, Senior Manager, AI and Optimization, IBM T.J. Watson Research Center. The role of the report review monitor is to ensure that the Panel gives full and fair consideration to the submissions of the report reviewers. The Board of Governors of the Council authorizes public release of an expert panel report only after the report review monitor confirms that the Council's report review requirements have been satisfied. The Council thanks Dr. Campbell for his diligent contribution as report review monitor.

Janet W. Bax, Interim President
Council of Canadian Academies

Executive Summary

The oil sands of northern Alberta contain an estimated 169 billion barrels of recoverable bitumen and span an area larger than Canada's three Maritime provinces combined (142,000 km^2). Their development through surface mining and in situ methods is expected to play a growing role in global oil supplies. Bitumen production, however, is resource intensive and generates a significant environmental footprint that is forecasted to grow alongside the growth in bitumen production if current methods of extraction and upgrading are used. And though recent oil price volatility will have implications for the rate of production growth, in the longer term production is expected to double with consequent environmental impacts on air, water, and land.

Bitumen production is also technology intensive with current and forecasted levels only now possible because of important innovations implemented over the past few decades. Given the importance of technology, the Government of Canada, through Natural Resources Canada (the Sponsor), with support from Environment Canada, asked the Council of Canadian Academies (the Council) to undertake an assessment of how new and existing technology can reduce the environmental footprint of oil sands development.

The Sponsor posed the following question:

> *How could new and existing technologies be used to reduce the environmental footprint of oil sands development on air, water and land?*

The charge included three sub-questions:

- *Using the latest deployed technologies and processes as a baseline, what are the potential environmental footprints of new oil sands projects, both mining and in situ?*
- *Using publicly available information, what extraction, processing and mitigation technologies are currently being researched, developed and demonstrated by the public and private sectors, and how could they reduce or further mitigate the environmental footprint of development on a project or per-barrel basis?*
- *What are the impediments (i.e., economic, regulatory, etc.) to the deployment, on an accelerated basis, of the most promising technologies?*

To address the charge, the Council assembled an independent, multidisciplinary panel of 12 experts (the Panel) from Canada and abroad. The Panel's composition reflected a balance of expertise and experience in bitumen extraction and processing methods and in relevant environmental impact areas.

Scope of the Assessment

Given the wide range of technologies that underpin oil sands operations, the Panel prioritized those with the greatest potential to reduce the environmental footprint in the next 15 years. Technologies related to surface mining and in situ methods were considered along with those related to bitumen upgrading, which applies to about half the bitumen produced today. Technologies at a very early stage of development were acknowledged but not evaluated. Finally, the Panel did not consider broader questions such as the pace of oil sands development, the impact of different oil price scenarios, and the rate of technology deployment needed to maintain ecosystem sustainability.

TOWARDS A SIGNIFICANT REDUCTION OF THE ENVIRONMENTAL FOOTPRINT

The evidence reviewed by the Panel points to the need for Canada to accelerate the pace of oil sands technology development to reduce the environmental footprint of bitumen and synthetic crude oil production in northern Alberta. Impacts on the region's air, water, and land, as well as contributions to global greenhouse gas (GHG) emissions, are forecast to grow as bitumen production doubles over the coming decades. Improvements in environmental performance are not keeping pace with understanding of impacts or, indeed, the growth of the industry.

The analyses indicate that reductions in the environmental footprint are achievable in each of the areas considered. Continuous improvement in the use of energy, water, and land on a per barrel of bitumen basis is necessary but insufficient to reduce the total footprint. New transformative technologies developed and commercialized over the next decade will be needed to extract this resource while also protecting the environment. Strong leadership, investment in new ways of bringing technologies from the lab into commercial application, and removal of barriers to implementation are required. Industry, government, academia, Aboriginal peoples, and other stakeholders all have key roles to play.

The oil sands have always had a deeply embedded culture of applied research and development (R&D). A century ago, a government chemist, Dr. Karl Clark, developed a method of liberating the bitumen from the sands. Pilot plants demonstrated and improved this technology and successful commercial production started close to 50 years ago with surface mining and upgrading of bitumen at Great Canadian Oil Sands (now Suncor Energy Inc.).

To unlock deeper oil sands deposits, the Alberta government formed AOSTRA (the Alberta Oil Sands Technology and Research Authority) in 1974, which led the way to the development of today's in situ production, which now surpasses output from surface mining. Along the way, thousands of innovations, large and small, have overcome the tremendous technical challenges associated with oil sands production. With the use of such technologies, over 2 million barrels per day of bitumen are now produced in the region.

Today, there are dozens of initiatives under way to improve process efficiency and environmental performance in the oil sands. There is also an environmental monitoring system operating in the region that is currently undergoing major enhancements. Billions of dollars in R&D and commercialization are being spent every year.

As impressive as these efforts are, they are not enough. This assessment of the evidence finds that most of the required challenges and solutions are multidisciplinary and have wide-ranging implications in highly integrated industrial and ecological ecosystems. The financial risks of implementing costly new technologies at the scale required are also immense. Moreover, despite a half-century of development, many seemingly intractable problems remain: what to do with tailings, how to treat and discharge water safely, how to reduce the amount of GHGs, and how to reduce the footprint on the land and wildlife caused by mining and in situ production. There are few simple solutions remaining to implement and no off-the-shelf technology.

Building on the past century of innovation, it may be expected that timely solutions can be found and implemented. But changing the pace of technology deployment will not occur without strong leadership, continued investment, and risk-taking by all. This report identifies the opportunities and the major barriers to overcome, highlighting the need for more rapid development and commercialization of promising technologies, and the opportunity for more truly collaborative approaches to solving these important issues.

DEFINING AND MEASURING THE ENVIRONMENTAL FOOTPRINT OF THE OIL SANDS

The Panel, for the purpose of this report, defined the environmental footprint primarily in terms of emissions from oil sands operations and related resource use. The footprint includes (i) GHG emissions; (ii) air pollutants (including sulphur oxide (SO_x) and nitrogen oxide (NO_x) emissions, fugitive emissions of organic chemicals, and particulate emissions); (iii) water withdrawal and the release of process-affected water (intentional and unintentional); (iv) disposal of tailings, a residual by-product of water-based bitumen extraction by surface mining; and (v) physical land disturbance, including habitat fragmentation and the stockpiling of solid by-products such as sulphur and coke.

The Panel's characterization of the environmental footprint did not consider specific thresholds. Instead, it took the broadest view of cumulative changes to the environment caused by oil sands activities and looked for technologies and strategies that could be employed to reduce the footprint both on an incremental and cumulative basis. What follows are the main findings associated with the environmental footprint of oil sands.

The environmental footprint of oil sands operations on air, water, and land is wide-ranging, significant, and cumulative, and will grow as production using current methods increases.

Assuming the use of current technology in oil sands development, emissions and use of resources will increase significantly in several areas as oil sands production expands. The effects are not always linear, nor are they necessarily limited to the oil sands region. GHG emissions, which include carbon dioxide (CO_2) and methane, for example, differ from other aspects of the environmental footprint of oil sands production in that their impact is global rather than local or regional.

Under current trends, GHG emissions and tailings disposal and related land disturbance are the most significant contributions to the environmental footprint.

GHG emissions from oil sands production using current technologies correspond closely to production levels, and could double over the next decade. Based on 2014 production forecasts, this would result in GHG emissions increasing from 76 megatonnes (Mt) of CO_2 equivalent (CO_2e) per year in 2013 to 156 Mt CO_2e per year in 2025 and to 182 Mt CO_2e per year in 2030. The growth in GHG emissions will be primarily driven by the increase of in situ production, which is much more energy intensive than surface mining. Improvements in GHG production intensity on a per barrel of bitumen basis have stagnated recently due to higher levels of in situ production. These intensities are projected to increase again in the absence of new technology and anticipated declines in reservoir quality.

The environmental footprint of tailings stems from the need to construct and maintain large ponds that can store fluid tailings for several decades or more before they can be reclaimed. These tailings ponds, which are some of the largest tailings facilities in the world (U.S. Department of the Interior, 2012), are both a legacy problem from past production and an essential part of current and new surface mining projects. While fluid tailings production intensity (the volume of fluid tailings per barrel of bitumen) is expected to decrease with the use of new technologies to meet provincial regulatory requirements (i.e., the Alberta Government's Tailings Management Framework for the Mineable Athabasca Oil Sands), total volumes are expected to increase over the next several years and then decrease well below Directive 074 levels. The resulting environmental footprint from tailings is multifaceted and includes the large areas of land disturbed; seepage of process-affected water into groundwater; the quantity, quality, and fate of process-affected water in the tailings pores; off-gassing of various chemical substances of concern (e.g., polycyclic aromatic compounds (PAHs), volatile organic compounds (VOCs) including benzene and methane); windblown fugitive dust from tailings sand beaches that contain chemicals of concern; risk of an accidental dam breach; and long-term reclamation of tailings ponds, which remains a significant technological, economic, and environmental challenge.

ASSESSING THE POTENTIAL OF TECHNOLOGIES TO REDUCE THE ENVIRONMENTAL FOOTPRINT

Opportunities to reduce GHG emissions lie primarily with in situ operations.

In situ operations, which are set to account for much of the new growth in production, are a major source of GHG emissions. This stems from use of natural gas to produce steam that is injected underground to mobilize bitumen for extraction. Under 2014 projections, GHG emissions from in situ operations are set to rise by 300% by 2030, in contrast to an 85% rise in those from surface mining. Upgrading emissions are expected to remain stable. This makes in situ operations an important focus for efforts to reduce GHG emissions. Because they are energy intensive, operators have been experimenting with technologies to reduce the amount of water that must be vaporized into steam to extract bitumen. These technologies include the use of solvents, alternative sources of thermal energy such as electricity, and modifications to the wells that involve, for example, vacuum insulated tubing and flow control devices.

Improvements in environmental performance are, however, likely to be incremental rather than transformative in the near to midterm. The use of solvent-assisted technology, now being piloted, suggests that energy use reductions of 10 to 30% on a per barrel basis are possible, which, combined with other measures to increase energy efficiency, could reduce GHG emissions by 15 to 35%. Several operators are experimenting with solvent-based technologies that do not require steam, which could potentially reduce GHGs related to energy use by 90% and bring per barrel emissions ($KgCO_2e$) to well below the level of U.S. average crude and other international sources. Their commercialization will be affected, however, by heterogeneous reservoir quality and by uncertainty about cost, solvent recovery, and potential risks of groundwater contamination, which may vary depending on the type of solvent used.

There are few technologies that can significantly reduce GHGs from surface mining. The use of mobile mining (mobile crushing units and at-face slurrying and digestion of the oil sands ore) is the most promising. For bitumen upgrading, industry is exploring several options to improve process yields but most of these technologies offer little potential to reduce GHG emissions. Operators are also commercializing a variety of partial upgrading technologies, which share the advantage of greatly reducing or eliminating the need for diluent in bitumen transport.

Key air pollutants from oil sands operations can be reduced through the use of existing and new technology, if widely adopted.

There are existing technologies to reduce air pollutants, many of which are already employed in the industry or are planned to be phased in. For example, emissions from surface mining will be reduced as operators phase in retrofits to existing fleets or upgrade to U.S. EPA Tier 2 haul trucks to meet reduced NO_x emission standards. Tier 2 haul trucks are expected to bring reductions in NO_x of between 30 to 50%. Another "quick win" for reducing air pollutants is the use of existing dust suppression technology in mining operations for haul roads and tailings beaches, which can keep pollutants largely contained or nearby to the mine site. Dust is an important vector for the local and regional distribution of pollutants such as some trace elements and PAHs. Flue-gas desulphurization technology has been installed in upgraders to substantially reduce sulphur compounds from upgrading stacks, while selective catalytic reduction can be used to reduce NO_x emissions from truck fleets. Air pollutants arising from decomposition of residual hydrocarbons in tailings ponds can be reduced by keeping froth treatment tailings, the major source of such contaminants (e.g., solvents, VOCs), out of the tailings ponds and treating them separately.

Although no single technology has been identified to solve the issue of fluid tailings reclamation, a suite of technologies may offer an overall solution that could provide the path to acceptable reclamation.

There is no single "silver bullet" technology that can significantly reduce the volume of tailings and significantly increase consolidation of the fluid fine tailings to make them reclaimable. Operators are, however, piloting and commercializing a range of technologies that, if used together and tailored for particular geological and geotechnical conditions, may constitute a "silver suite" of tailings management solutions that could provide the path to acceptable and timely reclamation.

Operator submissions, showing how the now suspended AER Directive 074 requirements (for reducing fluid tailings through fines capture and accelerating reclamation of tailings disposal areas) would have been met, imply that the total volume of tailings could be potentially stabilized at a level slightly higher than today, followed by a gradual decline as new treatment and reclamation technologies are deployed. However, no operator was able to meet the Directive's timeframes to achieve a fines capture of 50% (in addition to that captured in hydraulically placed dykes and beaches).

The current policy of zero water discharge and the absence of water treatment standards mean that, even if water recycling rates increase, tailings ponds will continue to exist and grow as bitumen production increases. A decline in ore quality as operators open new mines may also lead to an increase in fluid fine tailings production per barrel. Preliminary evidence suggests that water treatment technologies, if scaled up, have the potential to treat process-affected water for discharge. This lack of regulatory criteria for treatment and discharge of process-affected water is considered by the Panel a major impediment to both water and tailings management in the region.

While the Panel did not have the opportunity to assess the implications of the new Tailings Management Framework that replaced Directive 074 as of March 2015, it does note two important departures from Directive 074: a recognition of the potential need to consider the regulated release of process-affected water to the environment, and separate requirements for legacy tailings volume reduction.

Some 30 end-pit lakes are planned for the region, half of which will use water-capped fluid fine tailings as a reclamation strategy. A full-scale commercial demonstration of water capping is under way but it will take at least a decade of monitoring to demonstrate whether this technology can be effective in producing safe, ecologically productive lakes that do not require perpetual care and maintenance. Risks of groundwater seepage and contamination and breaches remain, and public acceptance of water-capped tailings technology is not assured.

Keeping separate the more toxic froth treatment tailings from the other more voluminous tailings streams, and effectively treating these streams for return to the mine, would address two important tailings problems. It would reduce fugitive emissions and toxicity that remains in froth tailings after treatment and avoid expensive reclamation issues unique to this material. It could also allow for the recovery of bitumen and metals.

Freshwater withdrawals, which are to increase mainly with growth in surface mining production, can be reduced through greater efficiency and water recycling. Solvent technologies have the greatest potential to reduce freshwater withdrawals.

While operators continue to improve their water recycling rates, much greater reductions could be realized with the use of solvent technologies. For surface mining operations, which are bigger users of fresh water, solvent-based extraction technologies could replace water in the removal of bitumen from the sand, potentially eliminating the production of fluid fine tailings. These technologies, however, are in an early stage of development, with little to no information available on performance in large-scale operations, costs, or environmental impacts from solvent release. For in situ operators, reduction in water intensity is being achieved on an experimental basis through the use of solvent-assisted technologies; longer-term solvent-based technologies would further reduce the use of fresh water.

For some substrates and some important land uses, reclamation technologies are unproven. To help maximize the reduction of land impacts, technologies need to be complemented by management-based approaches.

Provincial regulations require lands disturbed by oil sands operations to be reclaimed to equivalent land use that existed prior to disturbance. While mine reclamation for upland uses is a mature technology, lake, wetland, and riparian reclamation technologies are still under development. Technologies to enhance reclamation for wildlife habitat and traditional land uses by First Nations, such as the reclaimed grasslands that now provide habitat for bison at the Beaver Creek Wood Bison Ranch (overseen by the Fort McKay First Nation), are limited.

Ultimately, the greatest reduction in the land footprint will come with management-based approaches that complement the most promising technologies. For surface mining, for example, land impacts can be reduced by treating process-affected water for discharge and employing new tailings disposal technologies, which together can reduce the size of ponds and improve the consolidation of tailings, thereby reducing related land disturbance and ultimately speeding reclamation.

There are three significant opportunities to reduce mine sprawl and decrease the amount of disturbed land at any given time. First, a full integration of mine and tailings planning with reclamation and closure planning will allow for easier, faster, better, and more efficient reclamation. This requires both the development of regional closure planning to meet regional goals, as outlined in the Lower Athabasca Regional Plan, and planning that relies on true collaboration between individual mines, First Nations, regulators, and other stakeholders including in situ operations. Second, tailings technology development needs to have a much stronger focus on creating reclamation-ready tailings that have strengths sufficient for reclamation using the mine fleet, allow for better control and quality of seepage waters, and allow permanent reclamation and dam de-commissioning/de-licensing within a few years of deposition. The third approach is to be more assertive with tailings ponds closure. At present, many tailings ponds that are near capacity remain open, providing operators with an outlet for tailings should mine plans change and/or a risk insurance should issues arise with other tailings ponds. This, however, results in more active tailings ponds than necessary, an expanded size of the mine sprawl, and delayed reclamation.

Many of the technologies reviewed could reduce the environmental footprint of oil sands operations on an intensity (per barrel) basis. To reduce the footprint on an absolute basis at projected growth rates requires wide adoption of longer-term transformative approaches.

The Panel found no suite of technologies deployable in the near to midterm that would achieve an absolute reduction in the environmental footprint. This is due to a range of reasons including the rapid forecasted growth rate of bitumen production, the time needed to prove technologies in the field, significant technical challenges associated with tailings, the lower quality of new reserves, and the technologies' economic viability. Some promising technologies create environmental trade-offs such as increasing energy use. As a result, if bitumen production were to grow as forecasted in mid-2014, the environmental footprint in 2025 would still be higher than today's baseline even with widespread adoption of the most promising near to midterm technologies including water treatment technologies, new tailings technologies and land management approaches for surface mining, solvent-assisted technologies for in situ production, and carbon capture and storage (CCS) for upgrading.

To achieve absolute reductions, transformative approaches and technologies will be required to supplement the many important but incremental technologies that can achieve reductions on an intensity basis. These include the use of solvent-based technologies for in situ extraction that substitute water for solvent, and which could bring GHG emissions (CO_2e) from production below that of other crudes, including U.S. average crude oil. They also include substituting natural gas with alternative low carbon sources of energy, such as hydro, geothermal, or nuclear. Although theoretically able to reduce the GHG footprint significantly, these sources are a decade or more away from wide adoption, requiring significant investment to solve technical challenges or build the necessary infrastructure. Low carbon electricity sources would also support the deployment of electricity-based technologies, such as electromagnetic heating for in situ recovery. These technologies are not currently competitive with the use of natural gas.

Alternative low carbon energy sources that can be used in combination with the best new technologies and CCS, especially in the context of upgrading, should be given additional consideration. CCS offers a feasible set of technologies already being deployed in the oil sands and elsewhere in the world. The costs and risks associated with large-scale implementation, however, render CCS largely commercially unattractive for wide adoption in the oil sands. These costs vary substantially depending on the industrial process producing the carbon to be captured. Because they emit concentrated streams of CO_2, upgraders are the most likely candidates for current carbon capture technology. Practical considerations in retrofitting existing upgraders, however, likely limit carbon capture to 20 to 40% of their carbon stream. Wider adoption of CCS technologies will depend on further investment in R&D, as well as measures that make CCS applications more economic, such as a higher carbon price. As carbon prices rise, however, other alternative low carbon energy sources are likely to become competitive before CCS can be applied to all major sources of GHG emissions from the oil sands.

ACCELERATING THE DEVELOPMENT AND ADOPTION OF OIL SANDS TECHNOLOGY

Impediments to the accelerated adoption of the most promising technologies relate to the resources used, business decisions, and government policies.

For technologies to reduce the environmental footprint of oil sands development, the most efficient must be widely adopted across the industry. Impediments to such adoption include resource input factors (e.g., different reservoir characteristics, natural gas prices); business factors (e.g., scale of investment, development time, investment cycle); and policy factors (e.g., regulation, taxation, public investment in technology development).

Reservoir characteristics present a basic challenge to technology adoption. Since oil sands deposits are heterogeneous, varying in quality and viscosity, production techniques that are effective in one place may not be in another. This can limit the diffusion of specific innovations across the oil sands region. As for resource inputs, natural gas, one of the most important inputs in oil sands operations, is widely used to generate steam, electricity, and hydrogen (in upgrading). Low gas prices, however, discourage investments in, for example, solvent-assisted in situ recovery, use of alternative sources of power like hydro, and improvements in energy efficiency, all of which would reduce GHG emissions.

On the business side, the scale and capital intensity of oil sands projects encourage a preference for proven technologies. Risk aversion may lock in existing technologies and delay deployment of environmentally superior alternatives. Another impediment is the long lead time for technology development in extractive industries such as the oil sands, which often stretches from 10 to 20 years. Also, innovation is inherently uncertain: most of the technologies now being tested may fail or not prove commercial while the remainder may take many years to move from concept to market. Collectively, these business factors have important implications for the many new projects approved or in the application stage, for which technology decisions are now being made or will be made in the near future. Finally, the time value of money incents operators to defer non-productive expenditures (e.g., reclamation) until as late as possible. In the absence of policies or regulations to the contrary, the use of net present value economics discourages both development and deployment of technological solutions in these areas.

Government policy, or lack of, can also impede rapid adoption of new technologies. While Alberta's Specified Gas Emitters Regulation does impose a carbon compliance price on large emitters (as one option should they not meet annual CO_2 emission intensity reduction targets of up to 12%), it is only a modest economic incentive for firms to invest in new technologies that reduce GHG emissions, amounting to only a few cents per barrel. Similarly, the absence of regulations setting discharge standards for treated water, thereby allowing for its release back to the environment (as is commonly done in almost all other types of mining and other industrial operations), discourages operators from investing in water treatment technology and results in the continued growth of tailings ponds. Finally, governments can also help support efforts to better design mines for closure and perhaps to provide more incentive to accelerated reclamation.

Renewed collaborative innovation efforts that focus on environmental performance can accelerate development and adoption of new technologies.

Since no single solution to the environmental challenges is available, a "business as usual" approach to innovation is insufficient. Indeed, the current style of innovation, aimed at intensity targets, will not be enough. Without agreement on the extent and breadth of environmental footprint and related targets for reduction, collective innovation efforts will continue to suffer from a lack of focus.

The current track of continuous improvement is important but unlikely to bring forward transformative technologies. For this to happen, a renewed collaborative effort will be required for technology development and demonstrations. There is an opportunity, for example, for big demonstration projects on use of solvents that look at solvent content in the rejected waste solids in the case of mining operations, and at solvent impacts on groundwater and atmospheric emissions for in situ operations. Having leadership aligned across industry, government, and public research institutes towards a major effort in developing, testing, and adopting technologies will help reduce the environmental footprint, not only on an intensity basis but also in terms of their cumulative, absolute impact. This would include emphasis on fundamental scientific research and knowledge transfer and on collaboration between academia across the country, industry, and government, where research is multidisciplinary and partnerships are fully transparent. Also important is well-timed industry investment (in addition to investment magnitude) such that technologies are developed in the appropriate sequence to create a technology platform.

The Panel also identified the importance of regulations to accelerate innovation based on performance rather than technology mandates, and involvement of stakeholders to determine environmental priorities (i.e., global and regional footprint scales). Governments can help by developing a more complete regulatory regime that places a higher value on carbon, clarifies future water treatment and discharge standards, establishes simple and clear criteria for closure and reclamation, and generally helps to create the conditions for a healthy and dynamic innovation ecosystem.

Technology can have maximum impact in reducing the environmental footprint when the pace of its development and deployment aligns with that of oil sands development.

New technologies, especially those that can potentially bring major reductions in the environmental footprint, can take 10 to 20 years or more to develop and implement. The Panel concluded that oil sands development needs to reflect this reality if technology is to have maximum effect. The current pace of development requires the most promising technologies to be ready for broad adoption in the near term to prevent the locking in of existing and less efficient technologies to the majority of new projects. This underscores the need for a major collaborative effort to accelerate the development and adoption of the most promising technologies and solutions.

List of Acronyms and Abbreviations

AER	Alberta Energy Regulator
AI-EES	Alberta Innovates — Energy and Environment Solutions
AHT	autonomous haul truck
AOSP	Athabasca Oil Sands Project
AOSTRA	Alberta Oil Sands Technology and Research Authority
BATEA	Best Available Technology Economically Achievable
BLIERs	base-level industrial emission requirements
CAPP	Canadian Association of Petroleum Producers
CCEMC	Climate Change and Emissions Management Corporation
CCS	carbon capture and storage
CEMA	Cumulative Environmental Management Association
CERI	Canadian Energy Research Institute
CO_2e	carbon dioxide equivalent
COSIA	Canada's Oil Sands Innovation Alliance
CSS	cyclic steam stimulation
CTMC	Consortium of Oil Sands Tailings Management Consultants
ERCB	Energy Resources Conservation Board
ESRD	Environment and Sustainable Resource Development (Alberta)
FCD	flow control device
GHG	greenhouse gas
GHOST	Greenhouse Gas Emissions of Current Oil Sands Technologies
IMF	International Monetary Fund
JOSM	Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring
LARP	Lower Athabasca Regional Plan
LCA	life cycle analysis
MRBB	Mackenzie River Basin Board
Mt	megatonne
NEB	National Energy Board
NO_x	nitrogen oxides
NSERC	Natural Sciences and Engineering Research Council of Canada
OSTC	Oil Sands Tailings Consortium
PAC	polycyclic aromatic compound
PAH	polycyclic aromatic hydrocarbon

PM	particulate matter
SAGD	steam-assisted gravity drainage
SCO	synthetic crude oil
SDTC	Sustainable Development Technology Canada
SGER	Specified Gas Emitters Regulation
SOR	steam-to-oil ratio
SO_x	sulphur oxides
TLD	thin-lift dewatering
TGM	total gaseous mercury
VOC	volatile organic compound
WBEA	Wood Buffalo Environmental Association

Table of Contents

List of Figures

1

Introduction

- Charge to the Panel
- Scope of the Assessment
- Panel's Approach
- Study Limitations
- Report Organization

1 Introduction

Already central to the province's economy and a strategic resource for Canada, Alberta's oil sands are becoming an increasingly important global source of non-conventional hydrocarbon energy that could account for 5.5% of global oil supply by 2040 (IMF, 2014). Significant environmental impacts of oil sands operations (notably surface mining of bitumen ore, in situ recovery methods, and bitumen upgrading), however, are a source for concern. These impacts stem from the inherent properties of the resource and the energy intensive way in which it is extracted. Some impacts, such as greenhouse gas (GHG) emissions, notably carbon dioxide (CO_2), contribute to global environmental problems and affect Canada's performance in meeting international environmental commitments. Other impacts, such as land disturbance and creation of large tailings ponds, occur at the local or regional level, thus affecting the achievement of provincial or federal environmental objectives, such as preservation of biodiversity and water quality. The overall challenge is to reduce the environmental footprint of oil sands operations to stay within environmental limits as oil sands development expands (Alberta Government, 2009; RSC, 2010; NEB, 2013; CAPP, 2014a).

Technological innovation is essential in meeting this challenge. *Alberta's Climate Change Strategy, Responsible Actions: A Plan for Alberta's Oil Sands*, and *2014-2017 Business Plan: Alberta Innovates – Energy and Environment Solutions*, for example, all emphasize the central role of innovation in improving the efficiency and environmental sustainability of oil sands production (Alberta Government, 2008b, 2009; AI-EES, 2014).

To this end, the Alberta and federal governments, together with oil sands producers, have been investing in research and development (R&D) for new processes and technologies to improve the competitiveness of bitumen and reduce its environmental impacts. Building on some 75 years of oil sands R&D, there is now an R&D support system in place comprising several university-based research institutes, an industry consortium of leading producers, and several federal and provincial technology programs that fund various projects. Industry for its part is experimenting with new processes and technologies, several of which show promise for improving environmental performance.

Innovation is, of course, not new to oil sands producers; past technological breakthroughs, together with "learning by doing" over the past century (and rising oil prices), gradually made Alberta's oil sands competitive with conventional crudes (Isaacs, 2012a). The Clark Hot Water Extraction Process, the development of steam-assisted gravity drainage (SAGD) in the 1980s and 1990s for in situ recovery, and the hydrotransport of mined ore are but a few examples of process improvements that over several decades significantly increased the proportion of oil sands that are economically and technically recoverable (IHS Energy, 2011).

For all this past success, more innovation is essential to reduce overall environmental impacts. Growing evidence on the nature and magnitude of these impacts, and global efforts to reduce GHG emissions, have put Alberta's oil sands in the public spotlight just when production is set to increase substantially and, with it, the oil sands' environmental footprint. Without the deployment of improved and new technologies that can achieve significant, or even absolute, reductions in environmental impacts, growing social pressure could curtail future growth in oil sands operations and its promise of prosperity for the province and country.

1.1 CHARGE TO THE PANEL

To help understand the potential of new and existing technology to reduce the environmental footprint of oil sands development and inform government and industry decisions, Natural Resources Canada, with support from Environment Canada, asked the Council of Canadian Academies (the Council) to undertake an expert panel assessment to answer the following question:

> *How could new and existing technologies be used to reduce the environmental footprint of oil sands development on air, water and land?*

In addition, Natural Resources Canada included three detailed sub-questions in the charge:

- *Using the latest deployed technologies and processes as a baseline, what are the potential environmental footprints of new oil sands projects, both mining and in situ?*
- *Using publicly available information, what extraction, processing and mitigation technologies are currently being researched, developed and demonstrated by the public and private sectors, and how could they reduce or further mitigate the environmental footprint of development on a project or per-barrel basis?*
- *What are the impediments (i.e., economic, regulatory, etc.) to the deployment, on an accelerated basis, of the most promising technologies?*

The answers to these questions are intended to inform decisions on R&D priorities, regulatory development, industry investment, and public attitudes. To address the charge, the Council assembled a multidisciplinary panel of 12 experts from Canada and the United States — the Expert Panel on the Potential for New and Emerging Technologies to Reduce the Environmental Impacts of Oil Sands Development (the Panel). Panel members were chosen for their expertise and experience in the different bitumen extraction and processing methods and in relevant environmental impact areas. Members served on the Panel in their own capacity and not as representatives of stakeholders for their regions or interest groups. The Panel met in person four times over a 12-month period in 2013–2014 and also via teleconference calls.

1.2 SCOPE OF THE ASSESSMENT

The assessment focuses on the potential of technology to reduce the environmental footprint of oil sands operations in Alberta. As such, it does not address broader economic or social questions about the oil sands (e.g., should they be developed or should new pipelines be built?), nor does it evaluate the environmental and health impacts of existing operations, which have been the subject of other reports (e.g., RSC, 2010). To the extent that it considers environmental impacts, it does so to identify the processes that contribute the most to these impacts and the technologies that have the greatest potential to mitigate them.

Over the past few years, there have been several publications on the environmental impacts of oil sands (e.g., Pembina Institute, 2013a; CESD, 2011; RSC, 2010) and on technology roadmaps, including *A Greenhouse Gas Reduction Roadmap for Oil Sands* (Suncor Energy Inc. & Jacobs Consultancy Canada Inc., 2012) and the *Oil Sands Tailings Technology Deployment Roadmap* (CTMC, 2012a, 2012b). These have been complemented by various initiatives from COSIA (Canada's Oil Sands Innovation Alliance), a consortium of oil sands producers sharing knowledge, technology, and solutions to reduce tailings and GHGs, as well as impacts on water and land. The Panel's report differs from these other works by making technology its main focus rather than environmental impacts, and by seeking to identify technology opportunities across the entire environmental footprint of oil sands operations.

1.2.1 Geographical Setting

The technologies discussed in this assessment were identified in the context of Canada's oil sands located primarily in Alberta with some reaching into Saskatchewan. These oil sands are part of the Western Canada Sedimentary Basin, the geological region in which most of Canada's conventional oil and gas reserves reside. The oil sands cover an area of 142,000 km^2 (larger than the three Maritime provinces combined) in three geologically distinct regions of northern Alberta:[1] Peace River, Cold Lake, and Athabasca (Figure 1.1). The Athabasca deposit is geographically the largest of the three, holding the biggest reserves. It is the only one shallow enough to allow surface mining (RSC, 2010).

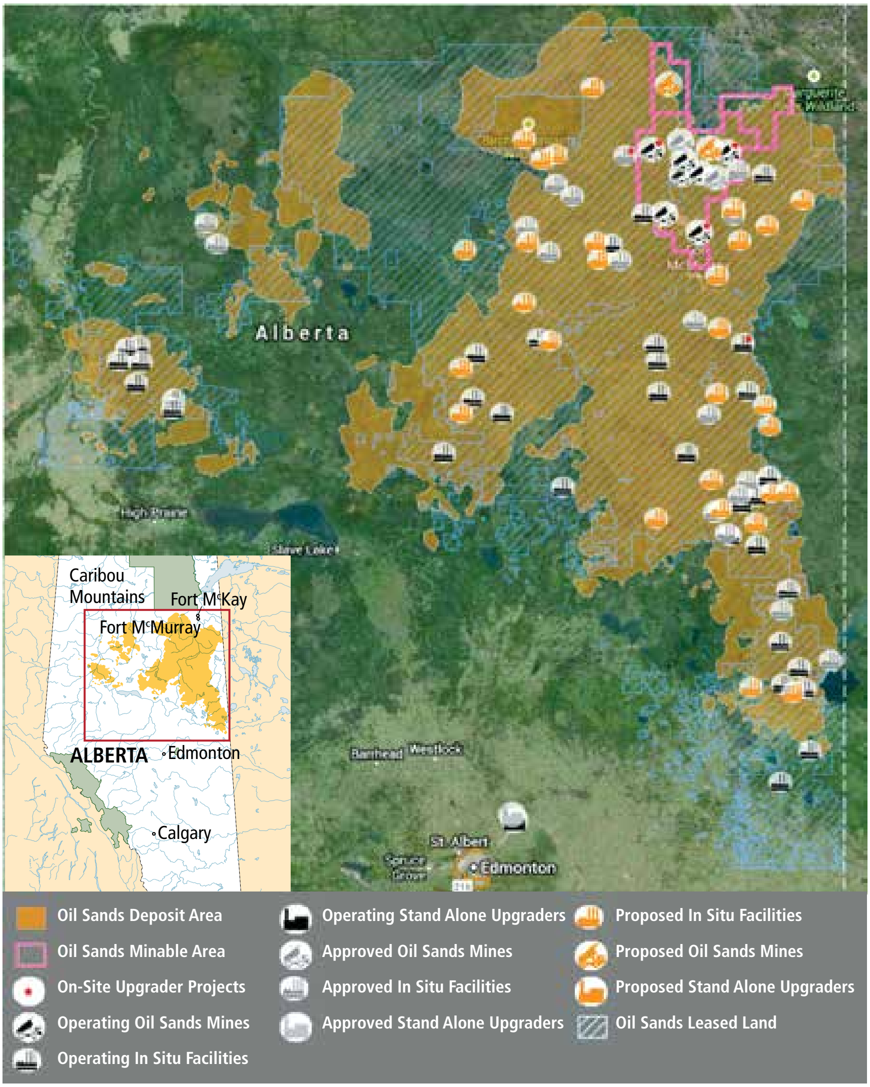
The geographical location of the oil sands is an important factor in their development. The oil sands are remote (Fort McMurray is 435 km north of Edmonton), raising the costs of bitumen production and transportation. They are subject to long, cold winters, creating challenging conditions for the technologies deployed to produce them. The reserves are situated under a rich boreal ecosystem that is inevitably disturbed by their development, raising concerns about the environmental impacts of exploiting them. And they are home to Aboriginal peoples, presenting economic opportunities for them but at the same time threatening their traditional land uses and potentially their health (McLachlan, 2014).

1.2.2 Extraction and Processing Methods

The Panel chose to review technologies related to the three dominant bitumen recovery and processing activities that are recognized as having the most significant environmental impacts: (i) surface mining extraction, (ii) in situ extraction, and (iii) upgrading of bitumen into oil products including synthetic crude oil (SCO). These are represented in Figure 1.2.

Surface mining, which currently accounts for 48% of bitumen production, extracts bitumen ore (typically 10% bitumen by weight) with shovel excavators and very large haul trucks. In this aspect, it is fairly similar to other types of large-scale open pit mining (e.g., coal, copper, iron). Mining starts with land clearing (boreal forest and its wetlands), followed by the removal and stockpiling of reclamation materials and overburden. The ore is mined and mechanically crushed into smaller lumps and subsequently processed with hot water and diluent (e.g., gas condensates) to extract the bitumen. About 90% of the bitumen in the ore that is mined is recovered. The tailings that are produced from using water to extract the bitumen are deposited behind dykes resulting in tailings ponds (also called tailings impoundments). All disturbed land is to be reclaimed progressively and returned to equivalent productivity as before development (Alberta Government, 2014c).

1 There are also smaller deposits in Saskatchewan.



Adapted with permission from aemera.org and the Alberta Government (2015)

Figure 1.1

Alberta's Oil Sands Operations, Current and Future

The map shows the location of existing, approved, and proposed facilities for surface mining, in situ extraction, and upgrading. These facilities form the basis of estimates made of the environmental footprint and of production through to 2035.

Surface mining is limited to the North Athabasca region of the oil sands where the bitumen ore lies within about 75 metres of the surface and covers an area of some 4,800 km^2, of which 715 km^2 (roughly the size of the city of Calgary) has thus far been disturbed (Pembina Institute, 2014a). This surface mining area accounts for approximately 34 billion barrels (20%) of Alberta's oil sands reserves,[2] putting an upper limit on surface mining production levels and their associated environmental impacts.

Outside the surface mineable area north of Fort McMurray, bitumen is extracted through in situ methods, which account for much of the anticipated growth in the oil sands. As of March 2013, more than 50 in situ projects were approved in Alberta (not including experimental pilot schemes) (AER, 2014g). These reserves cover about 85,000 km^2, representing some 95% of Alberta's active oil sands deposits (AER, 2014g), and could last several hundred years at current rates of production. In situ production methods involve pumping steam into the reservoir to heat bitumen to the point where its viscosity is low enough for it to flow to wellbores and be pumped to the surface. This is currently done commercially by one of two technologies: a high-pressure cyclic steam stimulation (CSS) process that uses mostly vertical, deviated, and horizontal wellbores; or a lower-pressure SAGD process that relies on a pair of superimposed horizontal wells, the upper well for steam injection and the lower one for oil production. Compared with surface mining, in situ methods have lower bitumen recovery rates and higher GHG emissions but use less fresh water and disturb less land directly. Because SAGD is now the most widely used in situ extraction technology,[3] this report uses it as the reference against which to assess opportunities to reduce the environmental footprint of in situ operations.

Finally, the Panel included upgrading, which involves partially refining bitumen into a SCO that can be transported by pipelines, because of its contribution to the overall environment footprint of the oil sands. Upgraders represent large capital and energy intensive industrial facilities that are similar to refineries. They are also the most complex of the oil sands operations, requiring various combinations of steam, electricity, hydrogen, and process fuel (Ordorica-Garcia *et al.*, 2012). Although several different configurations exist, upgrading typically involves treating the bitumen at high temperatures (450 to 540°C) to reduce

2 The current estimate of recoverable reserves is 169 billion barrels (Alberta Government, 2014g). Based on this estimate, approximately 20% of reserves can be accessed through mining.

3 The decision to use CSS or SAGD depends on a number of factors including the depth, quality, and thickness of the reservoir (Lunn, 2013). While SAGD is used primarily in shallower oil sands deposits, CSS is used mostly in thick oil sands in the vicinity of Cold Lake and Peace River where there is a thick cap rock.

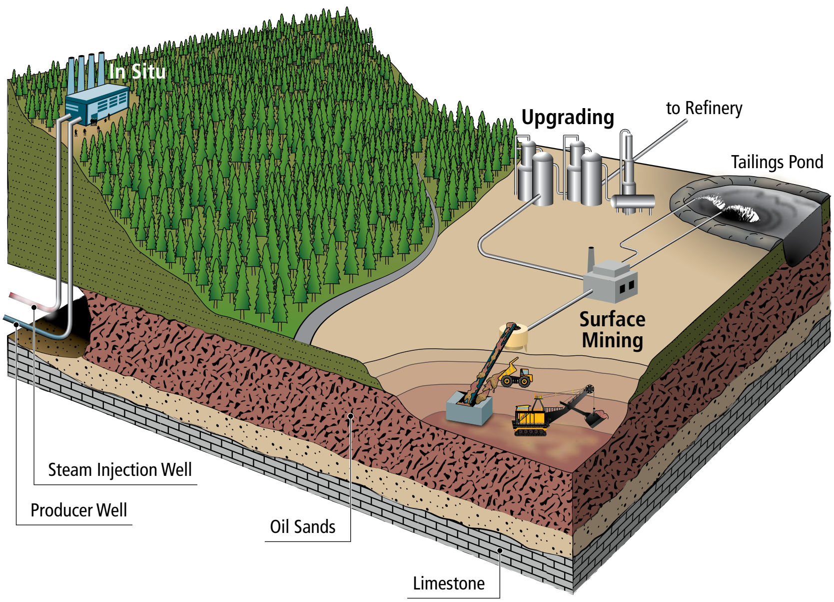


Figure 1.2

Simplified Illustration of Bitumen Extraction and Processing and Oil Sands Geology

Surface mining, which involves the use of shovels and haul trucks (portrayed on right), bitumen processing facilities, and tailings ponds, is limited to regions where the bitumen ore lies within about 75 metres from the surface. Outside the minable areas, in situ methods, including SAGD (depicted left), are used to access bitumen reservoirs, with the aid of steam, at depths below 200 metres. Upgrading facilities, portrayed in middle back, are similar in appearance to refineries, and are used to partially refine bitumen into a SCO that can be transported by pipelines. Each of these three processes has a distinct environmental footprint.

its density, viscosity, and molecular weight, to increase the hydrogen to carbon ratio, and to partially remove undesirable elements including sulphur, nitrogen, and metals (RSC, 2010; Choquette-Levy *et al.*, 2013).

A variation of upgrading is partial upgrading, which yields a less valuable product than SCO but requires less upfront investment and energy. This is an active area of technology development with the potential to reduce or eliminate the volume of diluent required for transportation[4] and to be more economic at a smaller scale than conventional upgraders.

4 Density of 19°API gravity or 934 kg/m3 and viscosity of 350 centistokes (cSt) at pipeline operating temperature of 7 to 19°C.

Figure 1.1 identifies the location of the facilities accounted for in this assessment. It includes existing facilities as well as those that have been approved and proposed.

1.2.3 Limiting the Scope

Given the current state of knowledge relevant to the charge, the Panel chose to limit the scope of its work in four important ways:

Timeframe: The assessment focuses on technologies with the greatest potential to significantly reduce the environmental footprint and that appear most viable given current knowledge. Technologies at an early stage of development (e.g., biologically assisted processes) are noted but not necessarily emphasized due to a lack of information and uncertainty about their potential performance. The technologies reviewed include those deemed by the Panel to be commercial in the near to midterm (about 15 years) as well as those that could become viable over the longer term (beyond 15 years).

Technologies: The assessment includes core process technologies that can improve efficiencies as well as "end of pipe" solutions that can remediate or mitigate pollution resulting from bitumen processing. The Panel defined *technologies* broadly to include management and operational practices that can improve efficiencies and reduce land use impacts, and modifications to equipment and processes. Cross-process technologies such as alternate sources of energy and carbon capture and storage (CCS) are also included because they are starting to be deployed in association with oil sands operations. The Panel, however, excluded technologies that generically have the potential to reduce the environmental footprint of oil sands operations but are not specific to them, such as the greening of the electrical grid and carbon offsets.

Environmental footprint: The charge is concerned with identifying technologies that could reduce the environmental footprint of oil sands operations. Accordingly, the Panel has defined the *environmental footprint* as the footprint that is associated only with the bitumen recovery and upgrading stages of oil production. Though in line with the monitoring objectives of the Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring (JOSM), the scope of environmental footprint used here is narrower than what JOSM will provide once fully implemented (Government of Canada, 2014). With an emphasis on emissions, it does not, for example, take into full account the cumulative impacts of these emissions on human and animal health or biodiversity.

Resource: The assessment excludes existing conventional production methods in the oil sands geographical area that use "cold flow" methods to produce less viscous reserves and are expected to account for only 5% of production by 2030 (IHS Energy, 2011). It also excludes technologies proposed for intermediate depths between 75 and 200 m that are not currently accessible for economic and technical reasons (Masliyah *et al.*, 2011).

1.3 PANEL'S APPROACH

In answering the charge, the Panel undertook a review of the relevant academic and engineering literature and official statistics, as well as reports from governments, international organizations, non-governmental organizations (NGOs), industry associations, and individual firms. The Panel also visited three sites in the oil sands region: Syncrude's surface mining operations at Mildred Lake, Cenovus's in situ operations at Christina Lake, and a Wood Buffalo Environmental Association air monitoring station in Fort McMurray. These visits provided perspective on the operational realities of incorporating environmental technologies into oil sands projects.

To guide its research, the Panel developed an analytical framework (presented in Figure 1.3) that focuses on technologies with the greatest potential to reduce the environmental footprint of the oil sands. The steps in its research were to identify the main inputs and outputs in the three main processes and their associated contributions to the environmental footprint.

With information on which processes and sub-processes are the sources of the most significant environmental impacts, the Panel identified technologies with the most potential to mitigate corresponding impacts. The Panel evaluated performance on the basis of available information and the expert judgment of its members. It then considered impediments to the deployment of technologies and estimated their potential to reduce the environmental footprint through to 2035. These estimates, which are based on 2014 bitumen production forecasts, illustrate the potential for reductions, assuming maximum diffusion of technologies and theoretical performances.

1.4 STUDY LIMITATIONS

Several important limitations inherent to the subject matter required that the Panel rely on the expertise, experience, and judgment of its members in reviewing and interpreting available information. Three important limitations warrant mention.

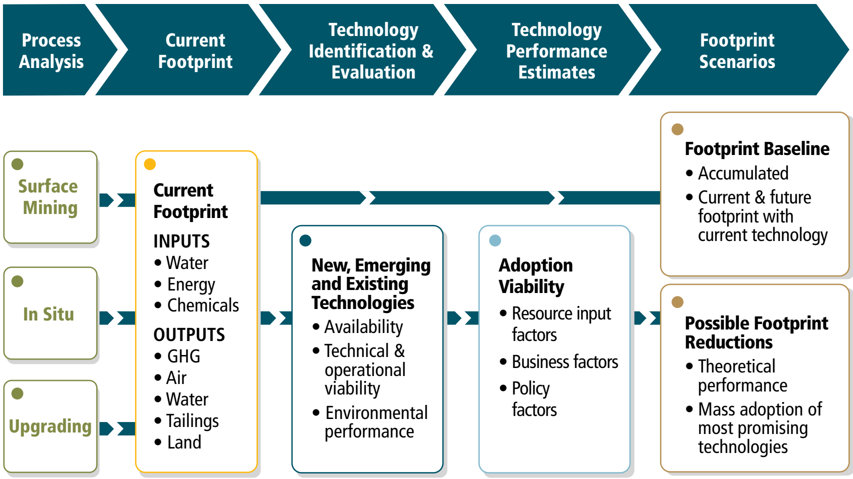


Figure 1.3

Analytical Framework Used for the Assessment

The figure sets out the analytical process adopted by the Panel and used for the assessment. It identifies the main stages in the analysis: defining the current environmental footprint associated with oil sands activities; identifying new, emerging, and existing technologies; assessing adoption issues; and, finally, assessing the potential of the most promising technologies to reduce the environmental footprint.

Uncertainty: A study, such as this one, faces uncertainty about future oil prices, technology development, and the policy and regulatory environment. First, the likely growth of oil production is heavily influenced by future prices for Alberta bitumen. The Panel has assumed that Alberta's oil sands production will continue to grow unconstrained by an external price shock or market access constraints that would undermine "business as usual" operations.[5]

Second, developing and bringing new technology to market is an inherently uncertain process that may stretch over an extended period and is subject to the risk of failure at any stage: R&D, prototype development, field trial, or commercial introduction. The Panel recognizes that technical and market uncertainties, as well as general political and economic uncertainties, can influence the outcomes of innovation projects. The more fundamental and radical the innovation, the higher the uncertainty (Freeman & Soete, 1997).

5 The Panel recognizes that the drop in oil prices that occurred in late 2014 will affect forecasted production trends used in this assessment, and the pace of technology deployment.

Third, through the rules they establish for the industry, the provincial and federal governments hold considerable sway over the deployment of technologies to reduce the footprint of oil sands development (discussed in Chapter 7).

Environmental Impacts: The report's findings are subject to the limitations of publicly available data. Understanding of the environmental impacts of oil sands development is evolving as environmental monitoring becomes more systematic. However, insufficient information exists on some possible impacts (e.g., solvents on groundwater quality or the implications of naphthenic acids in tailings ponds), including cumulative impacts (CESD, 2014). This makes it more difficult to estimate the potential contribution of some technologies in reducing the oil sands' environmental footprint.

Data Sources: Many of the emerging and new technologies identified in this report are proprietary and lack publicly validated data for either performance or environmental impacts. Some technology proponents may also exaggerate the performance of the technologies that they promote. As a result, claims of potential environmental benefits must be treated with caution.

1.5 REPORT ORGANIZATION

Chapter 2 defines, and quantifies where possible, the current and future environmental footprint of oil sands operations, given forecasted growth in bitumen production. Chapters 3, 4, and 5 then identify the technologies that can result in the greatest reduction in this environmental footprint for surface mining, in situ extraction, and upgrading. Chapter 6 focuses on cross-process technologies with the potential to significantly reduce GHG emissions, one of the biggest dimensions of the environmental footprint.

Chapter 7 discusses the main factors influencing the adoption of environmental technologies in the oil sands, estimates the possible reduction in the environmental footprint in five main impact areas (GHGs, air, water, tailings, and land), and considers which factors can best accelerate their diffusion. The assessment concludes by providing specific answers in Chapter 8 to each of the questions in the charge.

2

Defining a Baseline Environmental Footprint of Oil Sands Production

- How Oil Sands Operations Contribute to the Environmental Footprint
- Greenhouse Gas Emissions
- Air Emissions
- Water Use
- Tailings
- Land Impacts
- Conclusions

2 Defining a Baseline Environmental Footprint of Oil Sands Production

Key Findings

In absolute terms, the environmental footprint of oil sands production in all impact areas is expected to increase as the forecasted pace of oil sands growth exceeds the reductions in impact per barrel that can be achieved using current technologies.

GHG emissions are expected to increase proportionally with production growth. While incremental improvements in efficiencies can be expected to reduce GHGs overall, these reductions will be more than offset by a growing share of in situ production, which yields higher GHG emissions per barrel compared with mining.

The total volume of fluid fine tailings stored at the mines is expected to stabilize within the next decade due to the ongoing wide-scale adoption of new technologies. The size of tailings ponds is projected to continue to grow because of growth in production and because process-affected water must be stored on site. Other impacts related to tailings pond size, including fugitive air emissions, seepage losses, and the risk of catastrophic breach, are also expected to increase accordingly.

Fully integrated mine, tailings disposal, and closure planning, accompanied by greater focus on design-for-closure, especially for tailings consolidation and dyke design, will help better manage and reduce these risks. Furthermore, the notion that all areas in the mining landscape can be made to be “maintenance-free” or “walk-away” at closure is too optimistic. Planning and design should both attempt to explicitly minimize post-closure maintenance and plan for it.

For air, existing data suggest that current emissions lead to relatively few off-site, ground-level exceedances of objectives and standards set by Alberta and the Canadian Council of Ministers of the Environment. Exceedances that do occur are for odour-related total reduced sulphur compounds and for fine particulate matter, the latter influenced by forest fires and biomass combustion from land clearing. Emissions of sulphur dioxide are likely to remain more or less stable. However, emissions to air of nitrogen oxides are predicted to increase substantially depending upon the pace of new mine and in situ development.

While current water withdrawal rates are within environmental limits, future limits are uncertain. Climate change is expected to affect river flow rates, and growth of in situ production will require access to more waterways and groundwater sources.

This chapter defines the extent of the environmental footprint on air, land, and water arising from surface mining, in situ, and upgrading activities. Its purpose is twofold: to identify the areas that are of greatest priority for technological solutions, and to provide a baseline, "business as usual," footprint that can be used to approximate the degree to which new technologies might be able to reduce the cumulative footprint of future oil sands production. Following an overview of the oil sands processes that contribute to the environmental footprint in air, water, and land, the Panel identifies and, where possible, quantifies the emissions and pollutants stemming from these processes based on 2014 estimates of future production, as outlined in Appendix A.

For the purpose of this assessment, the "environmental footprint" is understood as "the contribution from emissions, energy use, water use, and land use that represent the effect of oil sands development on the environment." This definition is in keeping with JOSM, which identifies monitoring needs in six areas: air quality, acid sensitive lakes and accumulated deposition, water quantity/quality, aquatic ecosystem health, wildlife toxicology, and terrestrial biodiversity and habitat disturbance (Environment Canada & Alberta Government, 2012).

This analysis of the environmental footprint is location-specific, and does not incorporate a full life cycle analysis (LCA) (EPA, 2014) such as a "well to wheels" analysis for oil production and consumption. This is intentional, and reflects the fact that the scope of this report is limited to the footprint associated with only the bitumen recovery stage of oil production.

2.1 HOW OIL SANDS OPERATIONS CONTRIBUTE TO THE ENVIRONMENTAL FOOTPRINT

The process flow diagrams in Figures 2.1 to 2.3 depict the types and sources of emissions and pollutants for surface mining, in situ extraction (SAGD), and upgrading. The Panel developed this overview to highlight the main resource inputs and outputs/impacts of the sub-processes, and the risks involved.

For surface mining, the diagram (Figure 2.1) differentiates between two basic stages, and five sub-processes. In the mining stage, the use of large haul trucks is the main source of emissions and air pollutants.[6] This activity generates

6 Prior to the 1990s, most of the mining was done with draglines and bucketwheels, which were electrically driven and generated air emissions associated with the generation of electricity, but less emissions on site. Introduction of new diesel shovel/truck technology allowed for more flexibility in operations and lower mining costs. Syncrude retired its last dragline and bucketwheel in 2006 (Morgenstern & Scott, 1997; Syncrude Canada Ltd., 2007).

CO_2, nitrogen oxides (NO_x), and fugitive dust and fine particulate matter ($PM_{2.5}$), among other combustion and mechanical disturbance products. In the extraction stage, the most significant waste is the tailings slurry that results from the use of a water-based process to extract bitumen from the ore.

Once crushed, the oil sands ore is transported by a conveyor to a slurry preparation plant, where warm water and chemical aids (e.g., sodium hydroxide) are added to make a slurry that is then transported through a long hydrotransport pipeline. This process starts to liberate bitumen from the solid grains, breaking it into small droplets. The conditioned slurry is then discharged to large stationary primary separation cells where the bitumen floats to the top and is collected as primary bitumen froth, while the solids and process-affected water are discharged as a tailings slurry. Additional tailings result from the final froth treatment stage, which uses solvents to reduce bitumen viscosity and density and help remove the remaining solids and water (Masliyah *et al.*, 2011).

For in situ SAGD extraction (Figure 2.2), after the site has been prepared and well pairs drilled, the main processes relate to steam generation, water handling and treatment, transportation, injection, and the separation and treatment of produced fluids. Typically SAGD involves a number of steps. First, the steam is injected through the upper and lower wells to heat the oil sand in the vicinity of the wells. After the inter-well region is sufficiently heated to be mobile, SAGD mode starts when steam is injected into the upper well, and reservoir fluids and steam condensate are brought to the surface by the lower well (Gates & Larter, 2013). The main contribution to the carbon footprint comes from the combustion of fuel (natural gas) in the generation of steam resulting in the production of CO_2 (Gates & Larter, 2013). Land disturbances stemming from cutlines are also significant. Other air pollutants are caused by in situ reactions such as aquathermolysis and steam-rock reactions, which create additional CO_2 and hydrogen sulphide (H_2S) and other reaction products (Kapadia *et al.*, 2011). If the produced gas is combusted in the steam generator, the H_2S is converted to sulphur dioxide (SO_2). However, the largest contribution to CO_2 emissions is from fuel combustion.[7]

7 Cyclic steam stimulation (CSS), used mainly in the Cold Lake and Peace River deposits, faces challenges similar to those of SAGD.

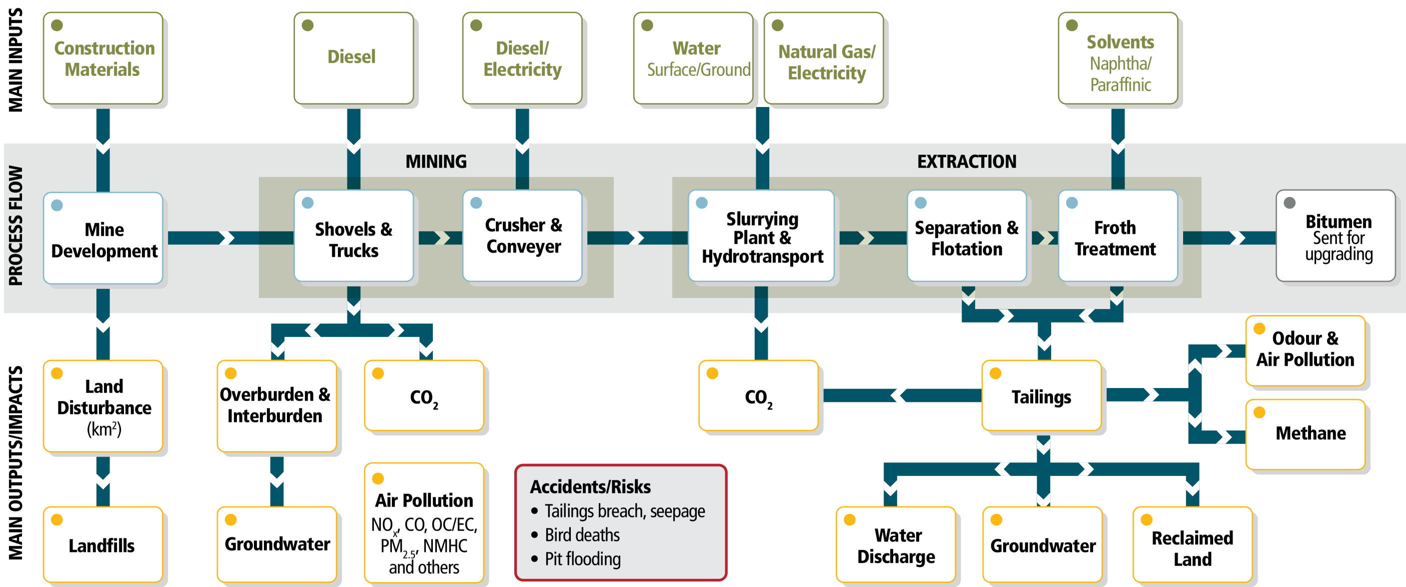


Figure 2.1

Surface Mining and Extraction Processes

The diagram outlines the basic processes involved in surface mining together with associated inputs and outputs. The main sources of pollution stem from the haul fleets, which contribute to GHGs, and from the resulting tailings generated in the extraction phase. Tailings that accumulate in large tailings ponds contribute to GHGs by way of fugitive emissions, disturb large land areas, and can have an impact on groundwater and surface water quality.

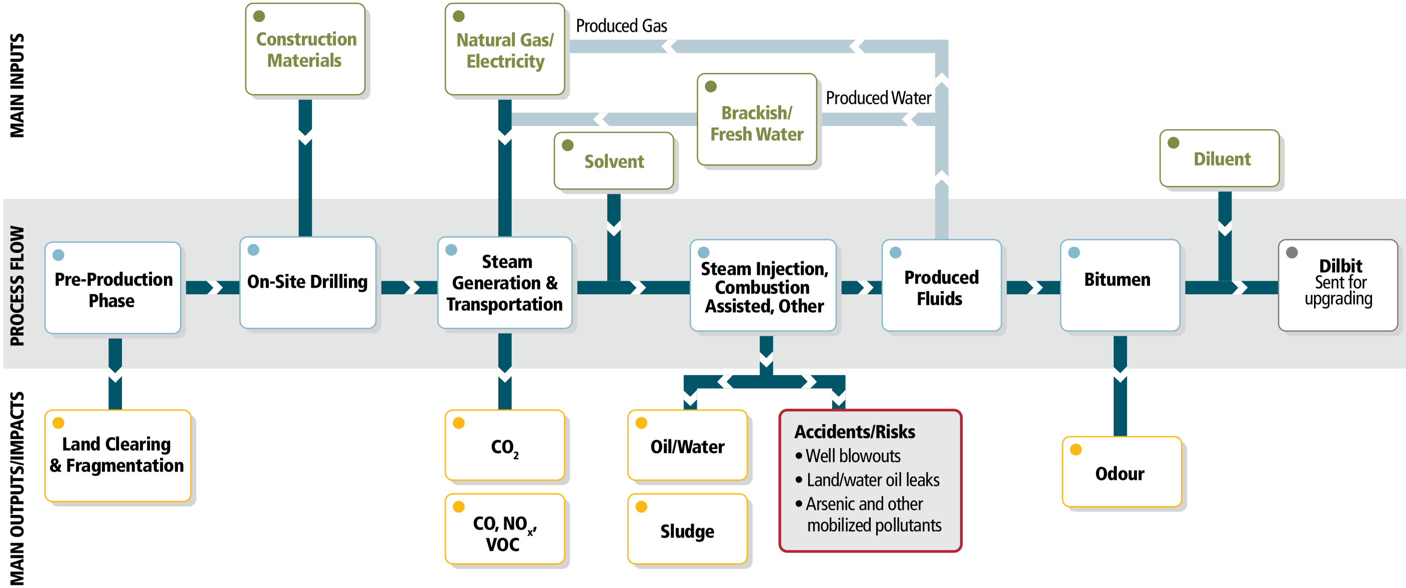


Figure 2.2

In Situ Steam-Assisted Gravity Drainage Processes

The diagram outlines the basic processes involved in in situ extraction, together with associated inputs and outputs. The main environmental contribution from in situ operations is from air emissions, notably CO_2, resulting from the burning of natural gas to generate the steam that is injected underground to heat the reservoir.

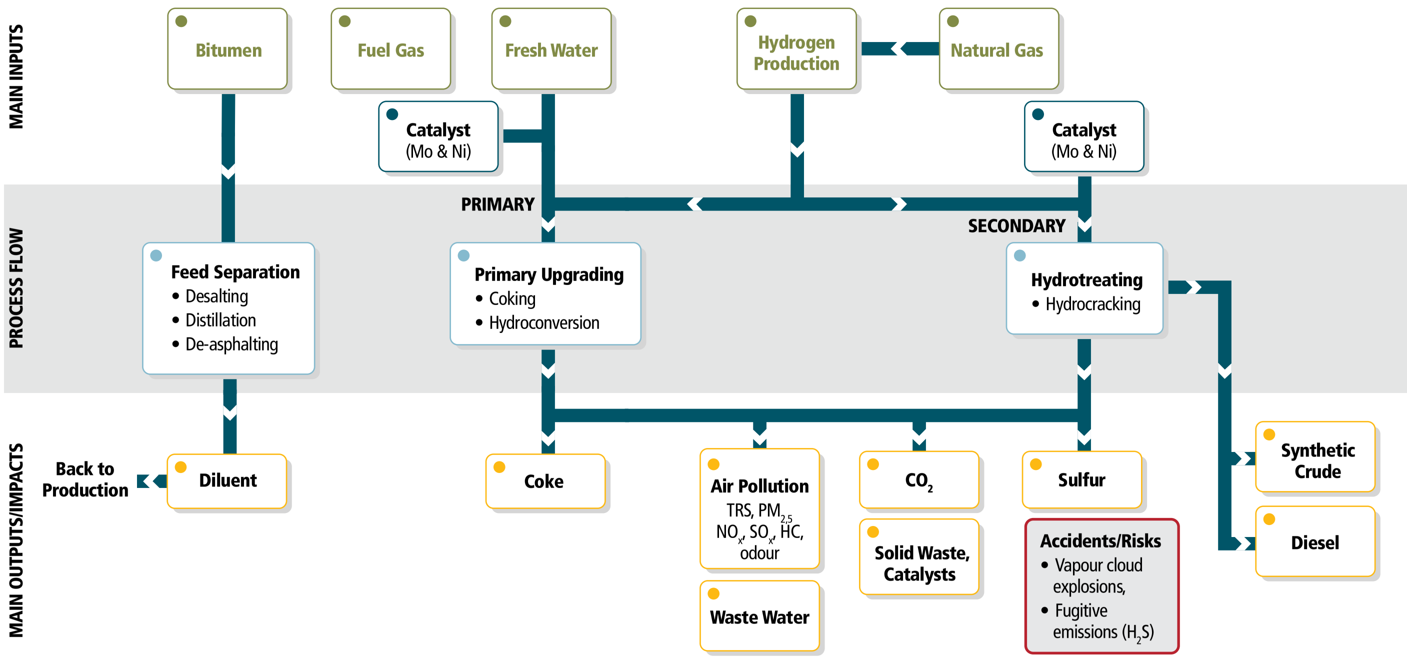


Figure 2.3

Bitumen Upgrading Processes

The diagram outlines the basic processes involved in upgrading together with associated inputs and outputs. Upgrading is a large point source emitter of a number of air pollutants, and of CO_2, a large portion of which comes from converting natural gas to hydrogen, needed for hydrocracking. Natural gas is also used for distillation and cracking. Upgrading results in a number of solid waste by-products including coke, sulphur, and fly ash.

Finally, Figure 2.3 depicts the process diagram for bitumen upgrading. Bitumen upgrading involves three steps: (i) feed separation; (ii) thermal cracking, which involves coking or hydroconversion to reduce the density and to increase the yield of lighter components; and (iii) hydrotreating, which uses catalytic hydrogen addition to improve the quality of the distillate products and remove impurities such as olefins, sulphur, oxygen, and nitrogen compounds. The conversion of natural gas to hydrogen in the thermal cracking stage represents the single largest source of GHG emissions from upgrading.

Upgraders are point source emitters of air pollutants (e.g., sulphur oxides (SO_x), NO_x, $PM_{2.5}$, volatile organic compounds) and generate a number of solid by-products that are process and location dependent. Those that use coking technology generate and stockpile coke, which is a solid black mixture of carbon with some sulphur, hydrogen, nitrogen, polycyclic aromatic hydrocarbons, and metals left as a residue after the more valuable components of the bitumen have been removed by cracking it at high temperatures (Gray, 2015). Most coke by-product is stored for future use; some is used for tailings reclamation, and some is sold off-site. Large quantities of accumulated coke are stored on land adjacent to upgraders, leading to impacts on land. Coke can also be used as a substitute for gas for heat, steam, or electricity generation. Coke combustion leads to higher emissions of GHGs and air pollutants than for natural gas. Coke can also be used in land reclamation and to create trafficable surfaces on dried tailings (see Chapter 4).

Elemental sulphur is another significant by-product stemming from the high sulphur content of Alberta's bitumen; for the Athabasca deposit, a typical value would be 5% by mass (Gray, 2015). Sulphur may be blocked for temporary storage on site or sold off-site as a by-product. Stored sulphur leads to land disturbance, potential for highly acidic run-off and groundwater (if not adequately contained) (Birkham *et al.*, 2010), and risk of accidental combustion and release of SO_2. Sulphur storage is temporary and all sulphur has to be removed at mine closure.

In summary, the contribution to the overall environmental footprint on air, water, and land varies considerably by process. All three processes contribute to GHGs, notably CO_2, and air pollutants such as NO_x and particulate matter (PM). The volume of water used and the quantity and quality of process-affected waste water produced vary by process as do the nature and extent of land disturbances. A geographic dimension to the footprint exists, whereby GHGs contribute globally to climate change while land disturbances and impacts on water and air are local or regional.

Production levels, however, have the largest influence on the respective contributions of the three processes to the environmental footprint. As a result of these forecasts, which are summarized in Appendix A along with their assumptions, the environmental footprint is expected to increase to varying degrees for most areas. What follows is a more detailed review of the contributions made by oil sands operations collectively to GHG emissions, air pollutants, water use, tailings, and land impacts, taking into account current and future production levels.

2.2 GREENHOUSE GAS EMISSIONS

GHG emissions, which include CO_2 and methane, differ from other aspects of the environmental footprint of oil sands production in that their contribution is global rather than local and regional. GHGs are released into the atmosphere where they contribute to climate change. Under the Copenhagen Accord of the UN Framework Convention on Climate Change, Canada has set a target to reduce national emissions by 17% over 2005 levels by 2020 (Government of Canada, 2013), with new targets expected in 2015 to be negotiated at the Paris climate conference. In 2008 Alberta committed to reducing GHG emissions by 50 megatonnes (Mt) of carbon dioxide equivalent (CO_2e) per year relative to the "business as usual" scenario. The scenario projects absolute provincial emissions to grow from 205 Mt CO_2e to more than 280 Mt CO_2e per year, thus allowing for continued increases in absolute emissions to about 230 Mt per year up to 2020 (Alberta Government, 2008a).[8]

Overall, CO_2 emissions originate mainly from the generation of steam for in situ production, conversion of natural gas to hydrogen for upgrading, hot water for the extraction of mine bitumen, shovels, and from the more than 200 haul trucks. For haul trucks, which operate some 6,000 hours a year and consume 230 litres per hour, CO_2 emissions are estimated at 3,700 tonnes per year per truck (Watson *et al.*, 2013b). In addition, several sources of methane emissions are created by venting of produced gas or as part of fugitive emissions from other sources such as pipelines or tailings ponds (Table 2.1).

8 Canada's 2014 report on climate change states that emissions for Alberta have reached 246 Mt CO_2e in 2011 and projects emissions to grow to 295 Mt CO_2e in 2020 (Environment Canada, 2014b).

Table 2.1

Sources of GHG Emissions in Oil Sands Extraction and Upgrading

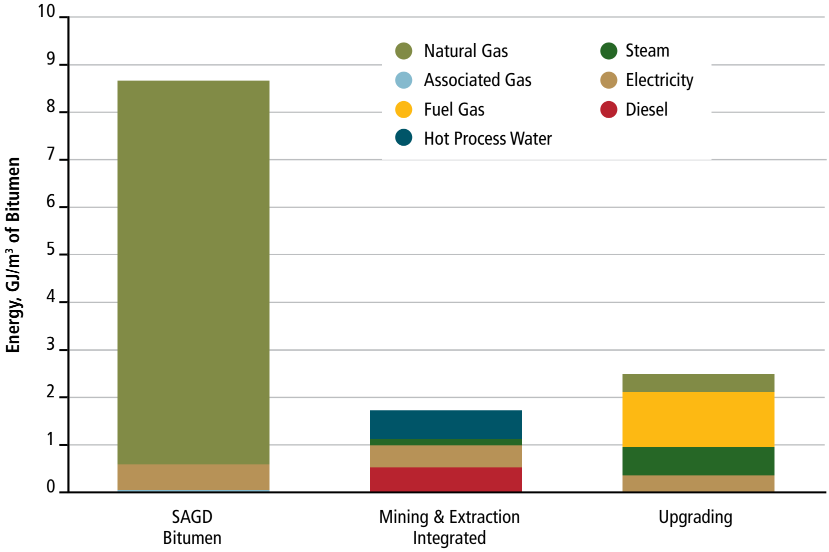
Source Category and Specified Gases	Mining	In Situ	Upgrading
Industrial Process (All)			Hydrogen generation and upgrading processes
Stationary Fuel Combustion (CO_2, CH_4, N_2O)	Thermal energy for Clark Hot Water Extraction Process	Steam generation	Electricity and steam for refinery
Venting/Flaring (CO_2, CH_4, N_2O, SO_2)		Produced gas	Hydrocarbon flaring and venting from various upgrading processes
Fugitive Emissions (CO_2, CH_4, N_2O)	Tailings	Solvent leaks	
On-Site (off-road) Transportation (CO_2, CH_4, N_2O)	Mine fleet (especially haul trucks)		
Land Conversion	Land clearing	Land fragmentation/ ecosystem degradation	

Alberta Government (2014f)

In situ production on a per barrel basis requires much more energy than either surface mining or upgrading (Figure 2.4). Natural gas is the fuel of choice for in situ operators, used primarily to generate steam but also injected in some reservoirs to provide artificial lift or pressure support. As a result, the main environmental impact from in situ production is CO_2, which comes from burning natural gas. The amount of natural gas used varies by the performance of the operation and is measured by steam-to-oil ratios (SORs); an SOR of 2.5, for example, means that 2.5 barrels of water, vaporized into steam, are required to produce 1 barrel of bitumen (see Box 2.1). Producing a barrel of bitumen at a SOR of 2.5 requires approximately 35 m^3 of natural gas,[9] which represents about 20% of the energy content of the recovered barrel of oil (RSC, 2010). GHG emissions associated with in situ production have been increasing rapidly, in line with the growth in production.

For upgrading, a high temperature (and therefore energy) is required to crack the large bitumen molecules into lighter distillate products. Operators typically use natural gas (and process gas generated during upgrading operations) to produce both heat and hydrogen and can achieve high levels of energy efficiency by relying on cogeneration plants to produce heat and electricity.

9 More water is used but it is recycled.



Reproduced with permission from Suncor Energy Inc. (2012)

Figure 2.4

Energy Use, by Oil Sands Process

SAGD is the most energy intensive of the three main processes with much of its energy coming from the burning of natural gas for steam generation. As the figure shows, it is about twice as energy intensive as mining and upgrading combined.

Nevertheless, the conversion of natural gas to hydrogen represents the single largest source of GHG emissions from upgrading. Full upgrading can require a large volume of hydrogen: up to 266 m^3 of hydrogen per m^3 of product (Shell Canada Ltd., 2005).

Producing this volume of hydrogen consumes at least half the natural gas used in the upgrading process (the other half is used as fuel for distillation and cracking). In a model of typical practice, for example, a bitumen upgrading facility uses steam methane reforming to generate 200 million standard cubic feet per day of hydrogen and, with an upgrading capacity of 100,000 barrels of bitumen per day, emits roughly 1.4 Mt per year of CO_2 (Suncor Energy Inc. & Jacobs Consultancy Canada Inc., 2012). Although upgrading accounted for about 5% of GHGs in Canada in 2011 (Environment Canada, 2013a), it is unlikely to expand in the future given current economic conditions in the industry (see Box 2.2). As a result, the environmental footprint of upgraders is not expected to grow at the same rate as for in situ production and mining, and technological opportunities will likely be limited to retrofitting existing facilities.

Box 2.1
Steam-to-Oil Ratios and GHG Emissions

The amount of GHGs produced by in situ operations is directly related to the SOR. As noted, an SOR of 3 means that three barrels of water must be vaporized into steam for every barrel of bitumen produced. Cumulative SOR (CSOR) denotes the average amount of steam required over the lifetime of a project, taking into account the steam required for initial reservoir conditioning. Instantaneous SOR (ISOR) is the amount of steam required per barrel at a specific point in time. The theoretical limit that can be reached assuming perfect heat transfer through the formation is equal to an ISOR of about 0.7. Most commercial SAGD operations, however, have an SOR of between 2 and 4 (Jaremko, 2014), although some have managed to improve this ratio by using solvents (see Chapter 4). Other operators, however, produce at significantly higher SORs (i.e., they have a lower net energy return), taking advantage of currently low natural gas prices (Gates & Larter, 2013). SORs reflect the technology in use as well as the quality of the reservoir, and can increase over time as the reservoir is depleted or if it is heterogeneous, leading to higher GHG emissions and water use.

Cumulative SOR, Selected In Situ Projects, April 2014

Company	Project	SOR
Cenovus Energy	Christina Lake	~2
ConocoPhillips Canada	Surmont	2.6
MEG Energy	Christina Lake	2.6 (2013/2014 ISOR)
Cenovus Energy	Foster Creek	2.4
Connacher Oil and Gas	Great Divide	4.0 (Pod One) 4.5 (Alger)
CNOOC	Long Lake	4.5-5.2 (2013 ISOR)
Suncor	Firebag	3.4

Data Sources: Connacher Oil and Gas Limited (2013); Cenovus Energy Inc. (2014a, 2014c); ConocoPhillips (2014); MEG Energy Corp. (2014); Nexen (2014); Suncor Energy Inc. (2014a)

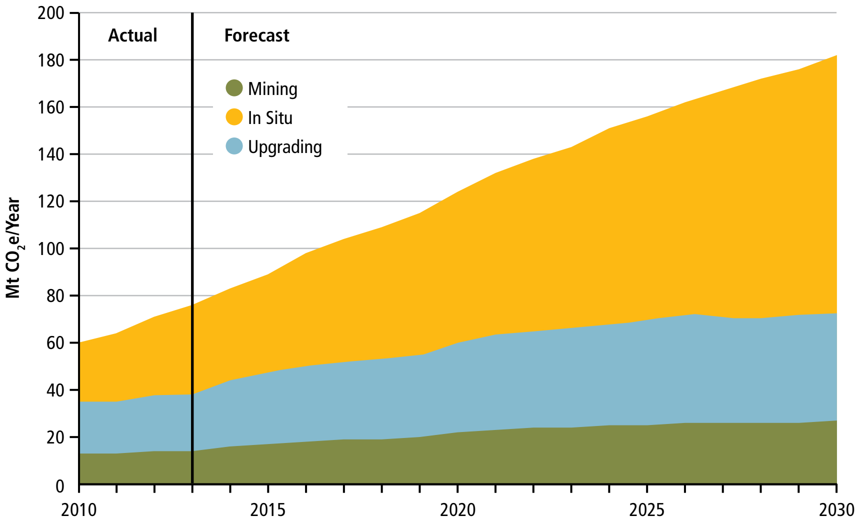
Box 2.2
Future of Upgrading in Canada

Most mined bitumen is upgraded to SCO in Canada. Conversely, most bitumen produced via in situ is not; instead, the bitumen is shipped as a diluted blend to refineries that can process heavy crude. Arguments in favour of upgrading close to production include the higher price that upgraded blends command, eliminating the need for large volumes of expensive diluent (which can take up to one-third of limited pipeline space and may require a return pipeline), and making use of waste heat from upgrading in the extraction process. While these factors have encouraged the construction of several upgraders close to the oil sands, recent economic conditions have led to the cancellation of additional upgraders. These conditions stem in part from the depressed price of light crude due to the shale oil boom in Canada's traditional export market, the U.S. Midwest (IHS Energy, 2013). This has narrowed the price spread between heavy and light oils, making investment in upgraders less attractive. In addition, the construction costs for greenfield plants in northern Alberta will always be more expensive than adapting existing refineries on the U.S. Gulf Coast and in Eastern Canada to process diluted bitumen.

Current and Future Levels

GHG emissions of future oil sands development are estimated using a partial life cycle analysis (LCA) of the "well to entering the pipeline stage" of a complete LCA model. These stages include all emissions associated with bitumen extraction and upgrading up to the point where the extracted raw product (bitumen, dilbit, synbit, or SCO) reaches a refinery on Canadian ground or leaves the country for export. Excluded are downstream emissions from refining through to final combustion, emissions from land use changes, and emissions from the use of petroleum coke, which is assumed to be stockpiled (see Appendix A).

The emission factors for estimating GHG emissions (expressed as CO_2e) from surface mining, in situ extraction, and upgrading processes have been derived from the Greenhouse Gas Emissions of Current Oil Sands Technologies (GHOST) model, a life cycle-based model that quantifies the emissions associated with the production of diluted bitumen and SCO (Charpentier *et al.*, 2011; Bergerson *et al.*, 2012). GHOST takes into account ranges for the parameters that determine GHG emissions based on actual production data submitted by oil sands operators, and allows estimating emissions using different LCA boundaries. The estimate presented below is based on emission factors that cover only the extraction and upgrading stages of oil sands production. It accounts for



Data Sources: Calculations use emission factors from Charpentier *et al.* (2011) and Bergerson *et al.* (2012); production forecasts are from CAPP (2014a)

Figure 2.5

Projection of Future Emissions from Oil Sands Development (Mining, In Situ Extraction, and Upgrading)

The figure displays estimates of direct and indirect GHG emissions based on data for actual production of raw bitumen and SCO up to 2013 and forecasted production levels up to 2030. With current technologies and reservoir conditions, total emissions can be expected to approximately double by 2025 (from 76 Mt CO_2e in 2013 to 156 Mt CO_2e in 2025) and continue to increase to approximately 182 Mt CO_2e by 2030. The largest share of that increase is expected to come from in situ extraction projects, which are expected to triple by 2030. Emissions from mining are expected to grow more slowly, by 85%. Emissions from upgrading are calculated under the assumption that all bitumen extracted through surface mining is (and will continue to be) upgraded.

the emission sources in Environment Canada's national GHG emissions inventory, including fugitive emissions and emissions from flaring while excluding, for example, downstream emissions (see Table A.1 for complete list).

Figure 2.5 shows the "business as usual" direct and indirect emissions that would result if oil sands production expanded as forecast by the Canadian Association of Petroleum Producers (CAPP) (2014a) using the average intensity of the technology mix currently deployed. With current technologies, reservoir conditions, and 2014 production forecasts, total emissions can be expected to approximately double by 2025 (from 76 Mt CO_2e in 2013 to 156 Mt CO_2e in 2025) and continue to increase to approximately 182 Mt CO_2e by 2030.[10] The largest share of that increase is expected to come from in situ extraction projects (37 Mt in 2013), which are expected to triple by 2030. Emissions from surface mining (14 Mt CO_2e in 2013) are expected to grow more slowly, by 85%. If the amount of SCO produced through upgrading were to double, as predicted by the Canadian Energy Research Institute (CERI), the National Energy Board (NEB), and the Alberta Energy Regulator (AER), emissions would grow by an additional 20 Mt per year by 2025.

2.3 AIR EMISSIONS

The environmental footprint of air emissions depends not only on emission factors (i.e., kg/fuel burned) and rates (i.e., tonnes/day), but also on atmospheric transport, chemical transformation, and eventual deposition through wet and dry processes, as well as the biological sensitivity and buffer capacity of the receiving environment. Assessing the contribution of air emissions to the environmental footprint, therefore, requires continuous monitoring of major emission sources and ambient air quality.[11]

In 2012/13, the Air Quality Health Index (AQHI) reported in all major urban centres and all provinces indicated a low risk from ambient air quality to human health for 95% of the time. Very high- and high-risk levels were identified for less than 0.5% of the time and resulted in most cases from higher levels of $PM_{2.5}$ measured during forest fires. It is important to note, however, that the values were calculated from hourly measured concentrations of three criteria air pollutants: nitrogen dioxide (NO_2), ozone (O_3), and $PM_{2.5}$. The AQHI does not account for any potential risk from total reduced sulphur or hydrocarbons that are measured at enhanced levels in the region during odour events.

The most recent report on the status of the Lower Athabasca Regional Plan (LARP) Air Quality Management Framework indicates that in 2012, no limits for air quality indicators were exceeded. However, 2 out of 13 air monitoring stations exceeded trigger level 3 for SO_2 and 1 station in 2013. None of the 9 stations measuring NO_2 exceeded trigger level 3 for NO_2 in either year. As required by LARP, Alberta Environment and Sustainable Resource Development

10 These estimates are higher than the projections made by Environment Canada in Canada's official report on climate change, which only considers direct emissions and accounts for incremental improvements in overall production efficiency.

11 Ambient air quality is monitored by the Wood Buffalo Environmental Association, whose data are publicly available (www.wbea.org).

(ESRD) will work with stakeholders whose activities result in emissions and determine management actions related to point and non-point source emissions (ESRD, 2014).

2.3.1 Nitrogen Oxides and Sulphur Dioxide

NO_x and SO_2 are emitted during the combustion of hydrocarbon fuels in stationary (e.g., steam or electricity generation) or mobile (e.g., mine fleet) sources. Approximately 50% of NO_2 emissions originate in steam production for in situ extraction and in upgrading, while the remaining 50% are reported as being emitted from mobile sources, mostly haul trucks and other large diesel-powered mining equipment. SO_2 is produced during the combustion of sulphur-containing fuels such as sour gas, and of non-desulfurized crude oil and petrol products; around 99% of the SO_2 emissions from oil sands production are stack emissions related to upgrading, vehicle emissions, and natural gas use for in situ production (Teck Resources Limited & SilverBirch Energy Corporation, 2011).

Both SO_2 and NO_2 are transported through the atmosphere and deposited through dry deposition processes (rather than through rain and snow), the predominant pathway active in the Athabasca oil sands region. They can also react to form secondary aerosols, or can be oxidized to acids and deposited down-wind through precipitation (a form of wet deposition). Acid deposition above critical loads can affect ecosystem function. Oxidized NO_2 (nitrous and nitric acid) and reduced (ammonia) forms contribute to total nitrogen loading, which may, when critical loads are exceeded, enhance vegetative growth and potentially result in excessive nutrients ending up in water bodies. NO_2 also acts photochemically to remove O_3 from the atmosphere.

Current and Future Levels

Meteorology greatly influences the potential local and regional contribution of NO_x and SO_2 emissions from each original stationary or mobile source. Wind and weather patterns prevailing during the emission period (along with source strength and height/exit temperature of the emission source) determine the ultimate chemical transformation and pattern of pollutant deposition. Studies of their impact on the Athabasca region have had mixed results. Some have found that soils in the Athabasca region are highly sensitive to acid deposition, resulting in low critical loads (Whitfield *et al.*, 2009, 2010a). Whitfield *et al.* (2010b) show that acid deposition varies across the region with critical loads already exceeded in one-third of their study sites. The release deposits accumulated in the winter snowpack can lead to acidic run-offs from the spring flood with uncertain consequences for the ecosystem, in particular organisms affected during hatching or breeding in the spring (WBEA, 2003; Kelly *et al.*, 2009).

Other research shows that soils in the Athabasca Oil Sands Area can recover from acid deposition over time; however, more research is necessary to estimate the risk of adverse effects from future deposition (Jung & Chang, 2012; Jung *et al.*, 2013). The most recently published study determines that the risk of soil acidification in the region is mitigated to a large extent by high base cation deposition (Watmough *et al.*, 2014). Similarly, research on acid sensitive lakes has so far not revealed signs of serious acidification (Hazewinkel *et al.*, 2008; RAMP, 2014).

In 1996, Alberta's oil sands operations emitted less than 450 tonnes of SO_2 per day. In 2012, according to Environment Canada (2013b), oil sands operations emitted 111,000 tonnes of SO_x, equal to about 300 tonnes of SO_x per day (t/d) on average. By 2016, due to new control technologies becoming operational at one facility, emission rates are predicted to fall to about 160 t/d (Clair & Davies, 2015).

Future emissions of SO_2 will be primarily influenced by regulation and demand for upgrading. Alberta ESRD requires large emitters of SO_2 to apply Best Available Technology Economically Achievable (BATEA) as standard for SO_2 emissions. In situ combustion and filtering technologies are comparable to those used in electricity generation. Current forecasts expect no or little expansion of upgrading in Canada (see Box 2.2). Future emissions of SO_2 are therefore likely to remain stable in the short term, followed by a gradual decrease as existing technologies are implemented in oil sands operations under BATEA requirements. Emission rates can be expected to decrease continuously, mostly as a result of the decline in the share of upgrading that takes place in Canada.

NO_x emissions are subject to the Multi-Sector Air Pollutants Regulations under Canada's *Environmental Protection Act*, which imposes base-level industrial emission requirements (BLIERs) on major industrial emitters as sector-specific performance standards. Similar to BATEA, BLIERs incentivize the adaptation and improvement of existing technologies for comparable processes (e.g., steam generation) (Environment Canada, 2014a).

The precise effect of these regulations on the trajectory of NO_x is difficult to quantify. While it is likely that emissions will increase in the short term due to the expected speed of expansion, it is unclear at which point absolute emissions will peak and start to decline as emission intensity declines.

A recent environmental impact assessment for the Teck Resources Frontier mining project, for instance, predicts an increase of total NO_x emissions of 121% over a 17-year period starting in 2009 (Teck Resources Limited & SilverBirch Energy Corporation, 2011).

2.3.2 PAHs

Polycyclic aromatic hydrocarbons (PAHs, a subset of polycyclic aromatic compounds, PACs) are a class of chemicals that occur naturally in coal, crude oil, and gasoline as well as in many organic materials, several of which are human carcinogens (EPA, 2008; CDC, 2009). They are released when coal, oil, gas, wood, garbage, and tobacco are burned. The main sources of PAH emissions in the oil sands are (i) fugitive dust released from haul roads, mining activity, or land use change; and (ii) combustion processes, e.g., stacks, mine fleets (Kelly *et al.*, 2009; Ahada *et al.*, 2014). The main natural source of (PAHs) in the Athabasca Oil Sands Area is forest fires (Percy *et al.*, 2012). PAHs generated from all sources can bind to or form small particles in the air.

Current and Future Levels

Real-world source emission testing has shown that PAH emission rates from upgrader stacks and heavy haulers in the region are relatively low (Watson *et al.*, 2012, 2013b). For example, concentrations of PAH measured in a terrestrial receptor were relatively low compared with other European/ North American studies using lichens as receptors. Concentrations within 30 to 40 km of mining/upgrading operations were highly correlated with crustal earth elements, indicating a near- to mid-range dust source. More volatile PAHs from combustion sources were found at low concentrations beyond 40 km (Kelly *et al.*, 2009; Studabaker *et al.*, 2012).

2.3.3 Mercury

Mercury emissions from oil sands operations are small and there is debate whether they are measurable or have impact. The Panel highlights them as an area requiring further research. Several characteristics of mercury make it challenging to account for in the environmental footprint of the oil sands. Its unique ability to re-emit following initial deposition through forest fires and other natural events effectively increases its atmospheric lifetime and global distribution. Mercury is therefore a global concern as it can be found to varying degrees in all ecosystems, including in places far removed from any major sources (Parsons *et al.*, 2013). Regional sources may therefore contribute only a share of the total mercury that is deposited in a given area; however, the exact share and sources are difficult to determine. Mercury also has bioaccumulative properties, which means that even low-level presence in the environment can lead to the accumulation of higher levels along the food chain.

Several studies have reached divergent conclusions on whether mercury emissions from oil sands operations are having an impact in the Athabasca aquatic ecosystem and food chain (Timoney & Lee, 2009; Evans & Talbot, 2012). Measurements of speciated and particulate-bound mercury in air are currently under way and expected to provide information on other sources of mercury.

Mercury levels in Athabasca fish were recognized as a risk to those who depend on it as early as 1975 (Schindler, 2013). However, it is not clear whether recent increases in concentrations in fish are the result of increased emissions from the oil sands. Kelly *et al.* (2010), for example, found mercury concentrations to be higher in water and snow near oil sands developments than in locations further afield. In contrast, Wiklund *et al.* (2012) found a decreasing trend in mercury concentrations in sediment cores downstream of the oil sands region since the 1990s, which did not coincide with increasing Canadian oil sands development. Furthermore, spatial patterns of mercury (and its natural isotopes) have provided no evidence for a significant anthropogenic point source of mercury from the oil sands developments, such as stack emissions. Mercury accumulation in a terrestrial receptor decreased with distance within 25 km of mining/upgrading sources (Blum *et al.*, 2012). This indicates fugitive dust as a transfer mechanism close to/in the middle of mining operations, consistent with the findings of Kirk *et al.* (2014).

Current and Future Levels

Ambient air mercury monitoring conducted since 2010 has shown that total gaseous mercury (TGM) concentrations at Fort McMurray are comparable to those measured at other stations in Alberta. When TGM concentrations were higher it was generally due to forest fire smoke and other long-range transport via the southeast and west. Yet when TGM concentrations were lower it was generally due to cleaner air from the Arctic (Parsons *et al.*, 2013). Future emissions from upgrader stacks are expected to remain stable as little investment in new upgrading capacity is expected. Emissions from mobile sources (haulers) and fugitive dust are likely to rise if increased mining activity leads to the deployment of more haulers. However, emission factors calculated from on-board hauler measurements indicate that release rates per hauler are relatively low, as are emissions rates from stacks tested (Watson *et al.*, 2013a, 2013b). Overall, a slight increase in mercury emissions can be expected.

2.3.4 Particulate Matter

Fugitive dust comprises particles that become airborne from open sources (e.g., unpaved and paved roads, mining pits, tailings ponds, unenclosed storage piles, quarry operations, construction sites). In Alberta, fugitive dust is an important source of ambient particulate matter (PM), which can be separated into three categories: total PM includes all particles with aerodynamic diameter less than about 100 µm; coarse particulate matter (PM_{10}) includes particles smaller than 10 µm but larger than 2.5 µm; and fine particulate matter ($PM_{2.5}$) includes particles smaller than 2.5 µm (Watson *et al.*, 2014).

Extended exposure to dust containing elevated levels of PM_{10} can cause adverse health effects, particularly if the dust contains crystalline silica, heavy metals, disease spores, and other toxins. In the Athabasca Oil Sands Area, dust plumes are often seen near the tailings sand beaches during high wind conditions, and behind vehicles driving on unpaved roads. Excessive dust deposits are found on surfaces inside residences near mining facilities, raising health concerns. Dust plumes can also reduce visibility, possibly leading to increased risk of accidents, lower productivity, and more mechanical wear on machinery (Watson *et al.*, 2014). Drifting sands and dust can affect adjacent reclamation.

$PM_{2.5}$ can penetrate deeply into the lungs, and high ambient $PM_{2.5}$ concentrations are of interest due to their association with adverse human health effects. Industrial emission sources to air of $PM_{2.5}$ include stationary (stacks) and mobile (off-road mine fleets, on-road transport), and other combustion sources such as biomass burning and forest fires. Industrial stacks are noticeable emitters and operators have installed PM control devices.

Current and Future Levels

In the Athabasca Oil Sands Area, $PM_{2.5}$ is measured continuously at 14 regional air monitoring stations (WBEA, 2015a). A trend analysis of data from four stations from 1998 to 2012 finds that no meaningful trends occurred over the 15-year period (Bari & Kindzierski, 2015). Average $PM_{2.5}$ ambient air concentrations across the four stations ranged from 3.7 to 6.6 µg/m^3, which were well below U.S. EPA (Environmental Protection Agency) $PM_{2.5}$ annual standard of 15 µg/m^3. There were, however, more than 100 exceedances whereby 1 hour $PM_{2.5}$ levels surpassed 80 µg/m^3. These all occurred during summer months, however, and have been shown to be associated with forest fires.

Contributions of fugitive dust to emission inventories and ambient concentrations can be modelled using dispersion simulations of contributions to receptor concentrations; however, emissions estimates are highly variable due to limited knowledge about the variance in meteorological, physical, and chemical factors on which the model is based (Watson *et al.*, 2014). Quantifying the contribution of future projects to PM air emissions is therefore difficult and highly uncertain. Fine PM concentrations are likely to increase with new mining developments, but the exact degree will depend upon the balance between new off-road engine technology implementation, the extent of new mining activity, the pace of reclamation, and operation of roads and tailings sand beaches.

2.3.5 Volatile Organic Compounds

Volatile organic compounds (VOCs) are a class of organic carbon-containing compounds that evaporate under normal indoor atmospheric conditions of temperature and pressure. VOCs can be very volatile (e.g., butane, methyl chloride); volatile (e.g., acetone, formaldehyde); or semi-volatile (e.g., naphthalene, benzenes).

VOCs are emitted largely from fugitive sources such as tailings ponds and on-site upgrading operations. In 2007–2008, the contribution of the oil sands to national VOC emissions was thought to be about 9.2%. Some VOCs are of concern to human health above certain doses, and some may react in the atmosphere to form ground-level O_3. VOCs are also known to have contributed to odour episodes in local communities such as Fort McKay, Fort McMurray, and Anzac (RSC, 2010; Percy, 2012).

Current and Future Levels

In the Athabasca Oil Sands Area, concentrations of 60 VOC species are measured at nine regional air monitoring stations once every six days. Some of these that are routinely measured (i.e., acetone, benzene, xylenes) have ambient air quality objectives set by Alberta (ESRD, 2013).

In 2013, the 10 most frequently and routinely measured VOC species (24-hour samples every six days at nine stations) were toluene (found in 77% of samples), acetone (71%), benzene (69%), isopentane (68%), methanol (65%), butane (58%), isobutene (47%), acetaldehyde (47%), alpha pinene (43%), and pentane (36%). Maximum 24-hour concentrations ranged up to 164 parts per billion (ppb) (methanol), 95th percentile concentrations were less than 38 ppb (methanol), and mean concentrations were less than 9.7 ppb (methanol) (WBEA, 2015b).

Existing case (2006–2009) VOC emissions are in the order of 250 t/d. The largest proportion (123 t/d) is from tailings areas, while 60 t/d are from mine faces, and 45 t/d from plant fugitives. VOC emissions under a reasonable development scenario were stated to increase by a factor of 2.5 (Teck Resources Limited & SilverBirch Energy Corporation, 2011).

2.4 WATER USE

The three major river basins (Peace River Basin, Beaver River Basin, and Athabasca River Basin) that span the oil sands area are the source of most freshwater withdrawals. While in situ production takes place in all three, all of the surface mines are located within the Athabasca River Basin.[12] Freshwater use in surface mining and in situ production has continuously decreased over past decades through the increasing use of recycled water, which constitutes 80 to 90% of water used for bitumen extraction from surface mining and often exceeds 90% for in situ extraction, and the use of other sources of fresh water.

2.4.1 Freshwater Withdrawal Rates

Current withdrawals of water amount to a small percentage of annual river flows. Between 2008 and 2012 total annual average freshwater withdrawals for surface mining and in situ operations were on average 173 million m^3 (ESRD, 2014e). In 2010, water use for in situ production corresponded to 1.2% of Beaver River flows, 0.03% of Athabasca River flows, and 0.006% of Peace River flows. Between 2006 and 2011 water withdrawals for surface mining represented on average 0.65% of Athabasca River flows, with a range of 0.48 to 0.75%. In surface mining, withdrawals from the Athabasca River between 2006 and 2011 constituted approximately 71% of freshwater intake with the remainder made up of surface water run-off collected at the mine (23%) and groundwater (6%) (Lunn, 2013). Similarly, freshwater withdrawals as a share of total water withdrawals for in situ production decreased from 57% in 2008 to 49% in 2012 due to increased use of saline groundwater. The literature suggests that climate change could lead to rapid changes in river flow rates if cumulative alterations of water flows result from multiple impacts, including warmer temperatures, increased frequency and severity of droughts, reduced inflow from glaciers and snow packs, and human activities such as agriculture (Schindler & Donahue, 2006; Warren & Lemmen, 2014).

In situ production uses large volumes of water, but does so from groundwater sources that it then recycles (up to 95%) (CAPP, 2014d). Over the last decade, in situ producers have significantly increased the proportion of underground saline water that they use to generate steam (from 28 to 47%) and have increased recycling, both of which reduce the demand for fresh groundwater. In 2012, the industry used 20.3 million m^3 of fresh water and 18.1 million m^3 of saline groundwater for in situ bitumen production (CAPP, 2014d).

12 The proposed Teck Frontier mine is the exception but not yet permitted.

Upgraders also use large amounts of water[13] for cooling, steam generation, and hydrogen production, but treat and recycle most of this water inside the plant (RSC, 2010). Net consumption can therefore easily be accommodated from surface sources. The water released to the environment from upgraders meets the same industrial wastewater standards as refineries and petrochemical facilities.

The main concern about freshwater use is that withdrawals from rivers during low-flow periods could have impacts on aquatic habitats and affect ecosystem functioning, in particular in the Athabasca River (Alberta Environment & Fisheries and Oceans Canada, 2007). While past withdrawals have been well within the limits set by the Water Management Framework for the Athabasca River (Alberta Government, 2015b), concerns have been raised in the scientific literature that the combined effect of lower flow rates as a consequence of climate change and higher withdrawal rates resulting from expanded mining could lead to withdrawals that exceed ecological limits during low-flow periods in the future. Several studies (Schindler & Donahue, 2006; Squires *et al.*, 2010; Rasouli *et al.*, 2013) show that the high flow rates of the Athabasca River decreased by almost one-third over the second half of the 20th century, and the expected impacts of climate change may lead to further rapid decreases over the next decades.

Others point out, however, that actual withdrawal rates have been much lower than allocated rates in the past and that industry can avoid withdrawing water during low-flow periods through on-site storage and improved water management (Lunn, 2013). The risk of excess water withdrawals is more difficult to assess for other rivers with lower overall flow rates where increased withdrawals could exceed limits more quickly during low-flow periods.

The industry's use of groundwater for in situ production raises several environmental concerns including the negative impacts of increasing groundwater temperatures (which may enhance the solubility and mobility of chemical constituents), the safe disposal of waste water with high concentrations of salts, the need to avoid large-scale communication between different aquifers as groundwater is withdrawn, and the absence of information about possible interaction between groundwater and surface water (RSC, 2010).

The mines also divert clean water away from mining areas, creating new reservoirs and wetlands, reducing flows in some streams, and increasing flows in other streams and constructed water courses. When mines close, a reconfigured surface water drainage system will be connected or reconnected to the surrounding natural system, with flows often combined/attenuated by large end-pit lakes (CEMA, 2013).

13 The Shell Scotford Upgrader expansion, for example, is designed to use 2,600 m^3/hr (Shell Canada Ltd., 2007).

The dewatering of the McMurray Formation and glacial aquifers ahead of and during mining is a significant source of water for mines. Some of this water is captured involuntarily and adds to the water storage requirements on site.

For surface mining, minimizing water import decreases the amount of water that has to be stored on site and minimizes costs of future water treatment. One trade-off of intensive water reuse, however, is the accumulation of salts in the process-affected water, which impacts soils in seepage zones; increases the risk of groundwater contamination; decreases water quality for on-site reclaimed streams and riparian zones, wetlands, and end-pit lakes; and potentially triggers the need for expensive long-term active water treatment.

Current and Future Usage

In 2012, oil sands operators withdrew on average 0.35 barrels of fresh water to produce one barrel of bitumen through in situ extraction ("make up" water constituting approximately 10% of total water use at average SORs and 3.09 barrels of fresh water to produce one barrel of bitumen through mining (Table 2.2)).

Table 2.2

Water Use Intensity of Mining and In Situ Production, 2008–2012

		2008	2009	2010	2011	2012	Average
Surface Mining	Barrels of Freshwater Withdrawal per Barrel of Bitumen Produced (Intensity)	4.39	3.39	3.06	2.77	3.09	3.34
In Situ	Barrels of Freshwater Withdrawal per Barrel of Bitumen Produced (Intensity)	0.56	0.43	0.40	0.37	0.35	0.42

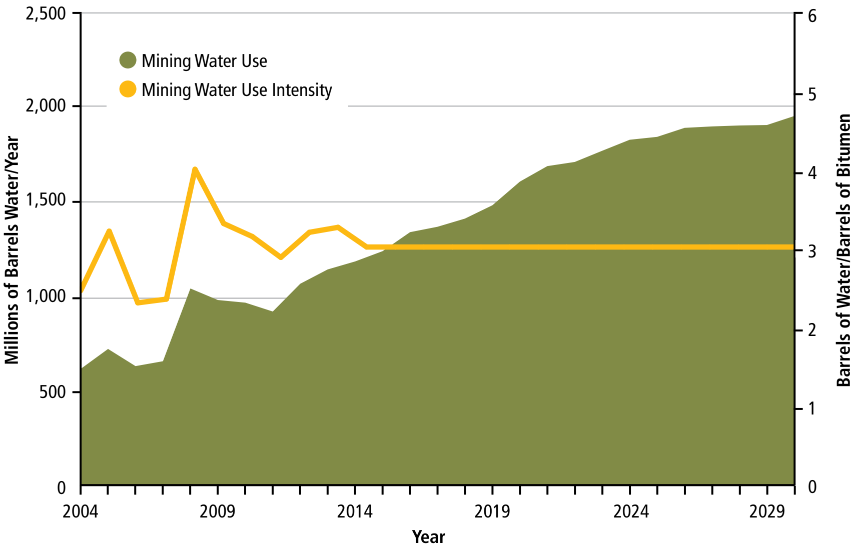
Data Source: CAPP (2013)

The amount of fresh water that needs to be withdrawn as bitumen production expands in the future will depend on whether this trend continues. Without further improvements in freshwater use intensity, freshwater withdrawals could more than double by 2030 as a result of expanded production (see Figures 2.6 and 2.7). The track record of water use reduction in mining and in situ extraction suggests that this estimate represents the upper bound of a range of possible outcomes and that the actual trajectory under current technology would likely be lower. Even in the current projection, where the share of mined bitumen declines from 50% to around 33% by 2030, freshwater intake for mining remains by far the highest share of total water withdrawals. In the absence of water use reductions, absolute water use for mining could substantially increase.

2.4.2 Surface Heave and Containment

For in situ steam-based recovery technologies such as SAGD, steam injection raises the pore pressure, which reduces the mean effective stress, which in turn dilates the oil sands formation. Furthermore, thermal expansion of the reservoir leads to volumetric expansion of the oil sands within the formation (Collins, 2007). This increased volume due to dilation and thermal expansion results in lifting of the overburden, which results in surface heave. In SAGD operations this vertical heave can be in the order of 20 to 30 cm (Suncor Energy Inc., 2013a), as shown in Figure 2.8. This represents an environmental concern with respect to (i) well casing failures (deformation of the formations leading to well failures that could potentially release steam or oil and produced water to shallower formations including aquifers), and (ii) land disturbance (which could impact operating plants and other surface features).

Containment of injected steam is becoming a more important issue in the context of steam, steam condensate, and mobilized bitumen moving from the oil sands formation to shallow aquifers or the surface. This is an environmental issue. However, it does not directly impact GHG emissions, though it can pollute shallow and surface water and environments. Containment issues can be dealt with through proper steam injection pressure management and cap rock integrity evaluation.

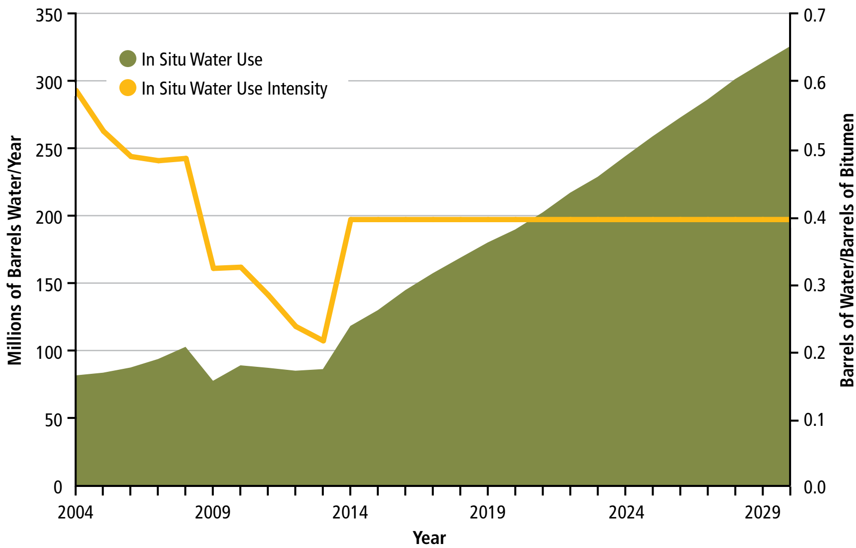


Data Sources: Calculations use data from AER (2014b) and bitumen production forecast from CAPP (2014a)

Figure 2.6

Past and Forecast Withdrawals of Fresh Water for Mining

The figure shows past withdrawals of fresh water for surface mining and projected future withdrawals based on the average intensity of freshwater use per barrel of bitumen during 2004–2013.

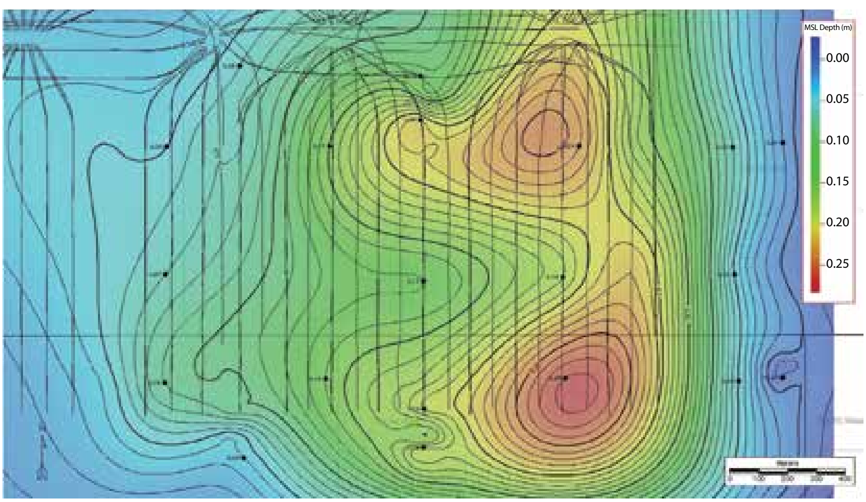


Data Sources: Calculations use data from AER (2014b) and bitumen production forecast from CAPP (2014a)

Figure 2.7

Past and Forecast Withdrawals of Fresh Water for In Situ Production

The figure shows past withdrawals of fresh water for in situ production and projected future withdrawals based on the average intensity of freshwater use per barrel of bitumen during 2004–2013.



Reprinted with permission from Suncor Energy Inc. (2013a)

Figure 2.8

Surface Heave for Pad 101 South at Suncor's Firebag Operation

The figure shows the heave contours from 2004 to 2012 for Pad 101 at Suncor's Firebag in situ operation. It shows a maximum rise of 28.4 cm, a maximum fall of -0.6 cm, and an average displacement of 11.7 cm.

2.4.3 Arsenic Precipitation in Shallow Aquifers Due to Steam Injection

Steam injection wells that pass through shallow aquifers heat the aquifers and in some cases cause mobilization of arsenic. Typically, when the water passing the wells has cooled down, the arsenic concentration returns to its background value. This can occur within a few hundred metres of the well. However, if landowners are withdrawing water from the shallow aquifer, monitoring equipment must be used. The Panel is aware that many operators are considering vacuum insulated tubing to avoid mobilization of arsenic.

2.5 TAILINGS

Tailings are a waste by-product of bitumen extraction from the mined oil sands ore, comprising sand, fines (silts and clays), residual bitumen, connate water, and the water used in hydrotransport and extraction. Figure 2.9 identifies several types of tailings that accumulate in tailings ponds including coarse tailings and fluid fine tailings generated from the main extraction processes, and froth treatment tailings, which are produced in the final froth treatment stage where bitumen is cleaned (CTMC, 2012a). Some tailings are co-disposed in large external and in-pit tailings facilities, and others in dedicated disposal areas (ERCB, 2009).

Whereas coarse tailings (mostly sand) are used for dyke building or form the tailings pond beach, the fluid fine tailings, a slurry of water, silt and clay, and residual bitumen, largely remain in suspension and accumulate over the life of a mine. As a result, large tailings ponds are required for storage of fluid fine tailings, posing a significant challenge for tailings reclamation. In 2011, the Government of Alberta estimated the total surface covered by tailings ponds at 175 km^2 (182 km^2 including dykes and other structures but excluding reclaimed coarse or fine tailings) (Alberta Government, 2014e; CAPP, 2014b). Of this surface, fluid tailings cover approximately 77 km^2, with tailings ponds holding a volume of 830 million m^3 (Pembina Institute, 2013a; CAPP, 2014b). The remainder of the surface is made up of coarse tailings.

There are a number of significant environmental issues related to tailings. These include the large areas of out-of-pit land disturbance caused by tailings, and the quantity, quality, and fate of process-affected water (in the tailings pores and as free water on the ponds) and its corresponding impact on reclamation, surface water, groundwater, and the cost of water treatment. Dusting from tailings sand beaches and erodibility of tailings dykes are also concerns as is the risk of catastrophic breaches.

Tailings contain a number of organic and inorganic compounds resulting from the extraction process including naphthenic acids, phthalates, asphaltenes, benzene, phenols, cresols, humic and fulvic acids, and toluene. They also contain petrogenic PAHs, dissolved solids (sodium, chloride, sulphate, and bicarbonate), and metals (lead, mercury, arsenic, nickel, vanadium, chromium, and selenium) (Allen, 2008b). The concentration of these contaminants depends on the composition of the oil sands ore, the degree of water recycling, and the type of bitumen cleaning process used (either paraffinic or naphtha based) (Czarnecki *et al.*, 2011). The most significant constituents of concern are the naphthenic acids and the salinity (CEMA, 2014).

Froth treatment tailings are a small component of the tailings produced (2 to 4%), but contain significant residues of the solvents (3 to 4 volumes per 1,000 volumes of bitumen produced) used to extract the bitumen. Froth tailings also have elevated concentrations of pyrite, naturally occurring radioactive materials, and some metals (CTMC, 2012b).

Some of these contaminants have been shown to seep from tailings ponds. Indeed, the seepage of process-affected water from some ponds into groundwater is a problem that is now more widely recognized (Ferguson *et al.*, 2009; Timoney & Lee, 2009; Morgenstern, 2012; Küpper, 2013; Frank *et al.*, 2014). Most of the tailings dykes are constructed from high permeability compacted tailings (Vick, 1990; Aubertin & Chapuis, 1991). Some dykes are constructed on low permeability foundations but others are built over pervious sand aquifers.

Another tailings issue is the safety of the dyke structures. Around the world, tailings dam failures occur at a rate of about 20 per decade, often with tragic results for humans and the environment (Azam & Li, 2010). The oil sands operations currently have dozens of large dykes, and the number continues to grow every year. The risk of failure of a large tailings dam in the oil sands constitutes an element of the environmental footprint. Consequently, additional steps to reduce the risk (probability and/or consequences) would reduce the environmental footprint. For dam (dyke) safety, there are three periods worth distinguishing: initial construction, operation, and closure (Oil Sands Tailings Dam Committee, 2014). On an annual basis, the highest risk is during construction and operation, but, on an absolute basis, if dams remain in the closure landscape, the risk of a breach may be higher due to the long time period of exposure.

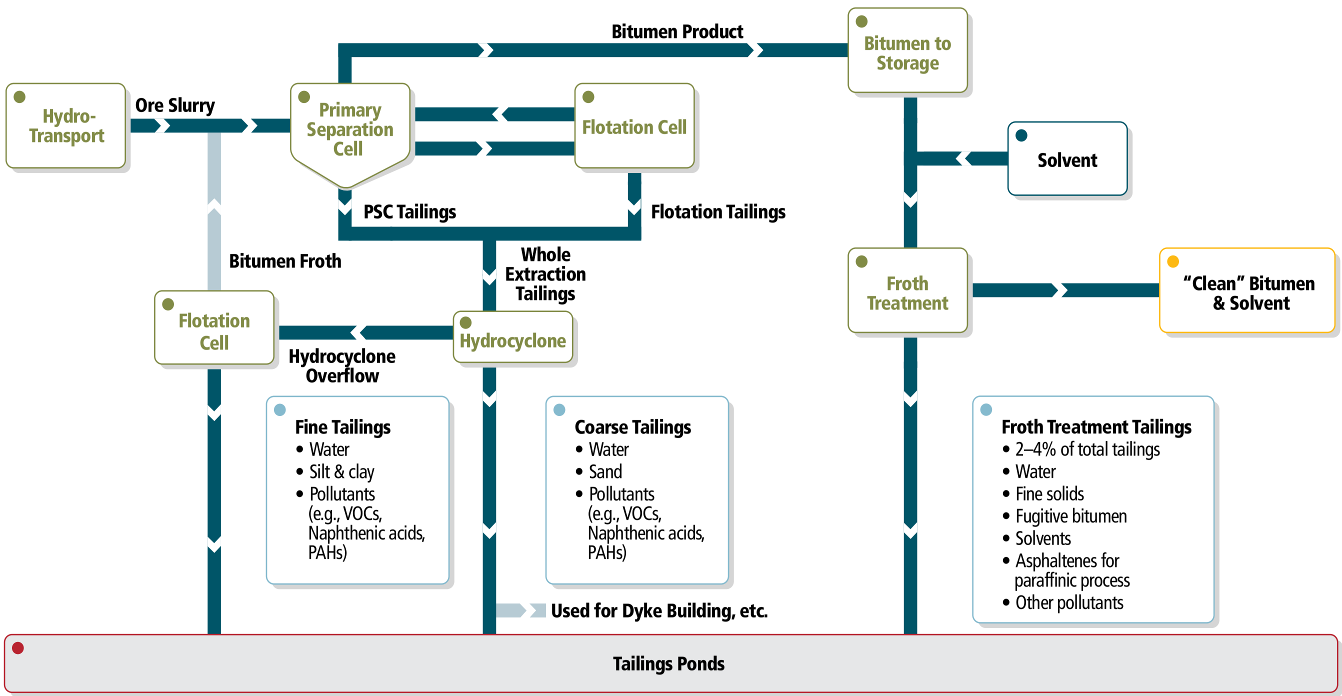


Figure 2.9

Typical Sources of Tailings

This figure, prepared by the Panel for illustration only, identifies the processes responsible for fine, coarse, and froth treatment tailings. Though only 2 to 4% of the total volume, froth treatment tailings is the main source of fugitive bitumen and solvents that end up in tailings due to the practice of discharging froth treatment tailings together with fine and coarse tailings.

Broadly speaking, past events documented in the literature indicate that there are several main areas of concern regarding the stability of tailings impoundments (Aubertin *et al.*, 2002b, 2011; Morgenstern, 2010; James *et al.*, 2011, 2013; Küpper, 2013; Frank *et al.*, 2014). First, the contractive behaviour of tailings is a complex design issue pertaining to undrained shear strength and static liquefaction (Finn *et al.*, 2000). Second, a sizeable degree of uncertainty exists about extreme events, with low probability and significant consequences, like large earthquakes and precipitation, which can cause dyke breaches. Given the longevity of tailings ponds and evolution of the retaining structures (which naturally tend to degrade over time), the likelihood of a breach tends to become high over a long enough time period. Tailings ponds have been shown to be vulnerable to extreme weather and seismic events,[14] and the risk evolves over time following an increasing cumulative probability (Vick, 1990; Aubertin *et al.*, 1997, 2002a). Third, although well engineered, structures such as tailings ponds and end-pit lakes are still prone to human error and poor decisions. As indicated in Chapter 3, there are opportunities to reduce the risks of dyke breach in the planning (including tailings technology selection), construction, operation, and closure phases of oil sands tailings facilities. In particular, reduction in the inventories of stored water and fluid tailings and adoption of a more robust and comprehensive design-for-closure approach are required to reduce these risks.

Current and Future Levels

Current regulations require that all process-affected water must be contained on site (zero discharge) including rainwater run-off, seepage water, and water produced from interceptor wells used to minimize off-site seepage of process-affected water. While the water is recycled — thereby reducing the amount of fresh water introduced into the system — the total amount of water stored in tailings ponds is accumulating. Repeated recycling also leads to a degeneration of water quality.

In 2009, the Energy Resources Conservation Board (ERCB, now AER) released Directive 074 (AER, 2009), which laid out performance criteria for the reduction of fluid fine tailings and accelerating reclamation. The main criterion from Directive 074 committed operators to use new technologies and dedicated disposal areas to achieve a fines capture of 50% (in addition to that captured in hydraulically placed dykes and beaches) in dedicated disposal areas where they have to form trafficable deposits (AER, 2009). Implementing this criterion would reduce the volume of new fluid fine tailings by up to 90% (AER, 2013a).

14 Seismicity in the oil sands region is low, but is a design consideration for dams and closure in the region (e.g., Atkinson & Martens, 2007; Klohn Crippen Berger, 2007).

However, this would require dewatering tailings to approximately 70 to 80% solids content, which is greater than what has been achieved to date with current technology (OSTC & COSIA, 2012; McKenna *et al.*, 2013; Sobkowicz, 2013; Read, 2014).

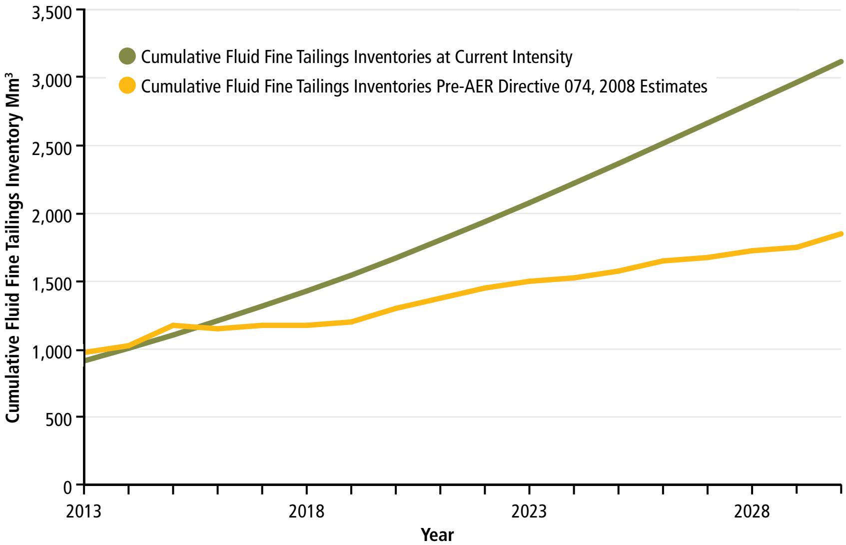
Operators were unable to comply with the initial timeframe (AER, 2013b; Pembina Institute, 2013a). In a review of implementation of Directive 074, the AER nonetheless concluded that operators had committed resources and made progress in moving towards the performance criteria (AER, 2013b). Based on this review, it appears that an accelerated roll-out of new technologies is currently under way, which could significantly reduce the amount of fluid fine tailings produced per barrel of bitumen extracted. At the time of writing this report, however, the slope and timing of this new trajectory were highly uncertain, making it difficult to estimate the future growth in fluid fine tailings inventories under technologies currently being implemented.

In March 2015, the Alberta government suspended Directive 074 and released a new framework entitled *Tailings Management Framework for the Mineable Athabasca Oil Sands* (Alberta Government, 2015a). While the Panel did not have the opportunity to assess the implications of the new Tailings Management Framework that replaced Directive 074 as of March 2015, it does note two important departures from Directive 074: a recognition of the potential need to consider the regulated release of process-affected water to the environment, and separate requirements for legacy tailings volume reduction.

Figure 2.10 therefore presents two boundaries for the potential growth in fluid fine tailings under existing technologies. The upper bound is based on average performance in the past (Mikula, 2012), whereas the lower bound represents the last forecasts submitted by operators before publication of Directive 074 (Houlihan & Mian, 2008), reflecting the state of technology deployment at that time. The boundaries cover a considerable range of possible outcomes: a worst case scenario shows fluid fine tailings inventories tripling between 2013 and 2030, and a scenario based on operators' expected technology deployment prior to Directive 074 shows a much smaller increase, to less than double of current inventories.

2.6 LAND IMPACTS

The disturbance from oil sands development goes through several phases: exploration, which results in cutlines and exploration roads; development, which requires construction access and initial preparation of the land; bitumen production; and reclamation to boreal forest end land uses, which is typically done progressively with a significant proportion that can only be done at the end of operations. The final phase is the relinquishment of the land back to



Data Sources: Calculations use data from Houlihan (2008), Syncrude Canada (2011, 2012), Shell Canada (2012a, 2012b), Suncor (2012), Imperial Oil (2012), Canadian Natural Resources Limited (2012)

Figure 2.10

Projected Inventories of Fluid Fine Tailings

The figure displays the projected growth of fluid fine tailings inventories at current production intensity (green line) and approximately as projected by operators in their 2008 submissions (prior to the implementation of Directive 074).

the Crown, which can only occur if the site does not require ongoing monitoring and maintenance.[15] Under Alberta's *Environmental Protection and Enhancement Act* (Alberta Government, 2014c), oil sands development is to be a temporary use of the land, with regulations requiring land to be reclaimed to a standard of equivalent capability.

The cycle from disturbance to relinquishment for an oil sands mine takes decades to a century or more (CEMA, 2012). Some facilities (refineries, roads, bridges) can be expected to outlive the site works and become an essentially permanent land use. Other land users, in particular indigenous land users, are excluded from operational areas and even from most reclaimed areas that remain under control of the operator.

15 McKenna (2002) and Morgenstern (2012) note that few large mines can expect to escape the need for at least some level of long-term maintenance. Most jurisdictions (but not Alberta) recognize the inevitability of long-term monitoring and maintenance at their mines and have regulatory frameworks that allow for this outcome.

Surface mining and in situ production have significant but different impacts on land. Surface mining drastically disturbs large contiguous areas through mining of overburden and ore, and through construction of anthropomorphic landforms such as overburden storage dumps, tailings ponds, and end-pit lakes and the associated surface water drainage system. In situ production uses linear features, including seismic lines, access roads, pipelines, overhead power lines, and well pads, which, unlike mining, leave large areas of forest but cause extensive fragmentation (Jordaan *et al.*, 2009). On the basis of the Long Lake in situ project, Schneider and Dyer (2006) estimate the density of this linear infrastructure to be 3.2 km/km^2.

As such, both types of land use lead to landscape fragmentation that extends beyond the area impacted directly. This makes quantifying the full impact challenging. Fragmentation affects ecosystem integrity and migrating species, as well as species requiring large habitats. Some species (e.g., woodland caribou, lynx, marten, fisher) appear particularly vulnerable to landscape fragmentation (Jordaan, 2012). Fragmentation can also reduce native biodiversity, lead to homogenization of flora and fauna (Noss, 1983, 1990), and bring about the degeneration or even collapse of neighbouring ecosystems. These impacts are expected to grow with the increase of in situ production.

2.6.1 Surface Mining

The land impact of surface mining includes land disturbed directly through mining activities or infrastructure development, as well as adjacent land where ecosystems will be affected by mining activities (land fragmentation). Disturbed land includes the area of the active mining pit as well as land occupied by infrastructure (extraction plants, roads, pipelines, storage facilities) and land used for tailings ponds and storage of overburden. While oil sands operators report the amount of land disturbed, the impact of land fragmentation is much more difficult to estimate. As of December 2013 the total active footprint of Alberta's oil sands mining activities was 894.9 km^2, including 182 km^2 of tailings ponds.

There is some uncertainty about the impact of overburden storage on groundwater or adjacent surface water bodies. Flushing of salts and naphthenic acids from these overburden storage landforms, as groundwater or surface water, has been extensively studied using instrumented watersheds (Dobchuk *et al.*, 2013).

Oil sands operators are required by law to remediate and progressively reclaim all land disturbed by mining (and tailings) activities (AER, 2013c). This requires returning land to a self-sustaining boreal forest, wetlands, or equivalent ecosystem with local native vegetation and wildlife. In 2013, 83.4 km^2 (approximately

10% of the disturbed area) was under active reclamation, of which 70.9 km^2 were classified as permanently reclaimed. A 1 km^2 area of land was certified as reclaimed land and returned to the provincial government (ESRD, 2014a).

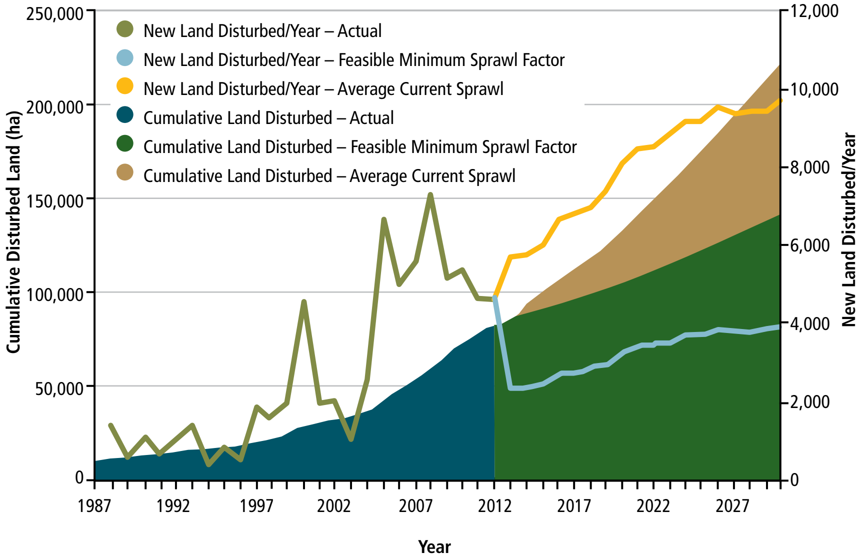
Many dykes in the region have also been partially reclaimed. Suncor's 2.2 km^2 Pond 1 (Wapisiw Lookout) was filled with sand and is the region's first reclaimed tailings pond (Suncor Energy Inc., 2011). In 2012 Syncrude reclaimed a 0.54 km^2 watershed with an experimental fen (wetland) ecosystem over a sand-capped deposit of composite tailings (Pollard *et al.*, 2012; Syncrude Canada Ltd., 2014).

Current and Future Levels

Projecting the future land footprint requires several metrics that capture the area of land disturbed directly through mining and in situ operations, the effect on adjacent ecosystems (buffer zone), and the time delay between the beginning of disturbance and permanent reclamation (which determines the average active footprint of a mine).

For surface mining, the total land footprint of a mine includes both the area above and near the ore body to be extracted (mine pit) and the areas adjacent to the mine pit required for processing and transportation infrastructure, including access roads, extraction plants, pipelines, storage tanks, temporary overburden storage, and tailings ponds. As such, the footprint will always exceed the size of the recoverable ore body. The extent to which it exceeds that of the mine itself can be expressed as the "sprawl factor," which is defined here as the ratio of the size of the ore body to the total active mining footprint. A sprawl factor that is equal to 1 indicates that the mine's total active footprint never exceeds the size of the ore body. Taking into account the feasible minimum disturbance necessary to be able to mine, Jordaan *et al.* (2009) calculate the minimum theoretical sprawl factor to be 1.27. Based on land disturbance data, surface mining operations are estimated to have a sprawl factor of 3.15, two-and-a-half times that of the theoretical minimum (see Appendix A).

Figure 2.11 shows the potential range for the future land footprint of mining activity based on CAPP's 2014 production forecast. The upper bound extrapolates past intensity measures, whereas the lower bound is based on a theoretical sprawl factor of 1.27. The actual footprint can be expected to be significantly below the upper bound as new mines will have access to existing mine pits for the storage of overburden, tailings ponds, and other activities, as well as existing infrastructure. The use of these existing elements is constrained by limited scope for collaboration (between operators) or integration of activities that could minimize the sprawl factor.



Data Sources: Calculations use data from Jordaan *et al.* (2009), AER (2014a, 2014d, 2014f), and bitumen production estimates from CAPP (2014a)

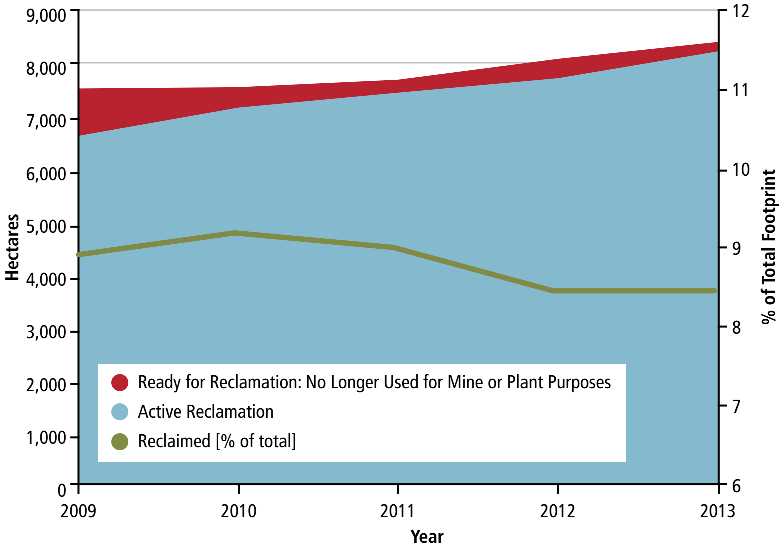
Figure 2.11

Range of Possible Future Mining Land Footprint

The figure shows the potential for reducing the land footprint of mines by contrasting an upper bound that is based on an average sprawl factor, to a lower bound based on the theoretical minimum feasible sprawl factor of 1.27. The shaded area represents cumulative disturbed land, while the lines plot the rate of new land disturbed (per year). Future projections assume that all bitumen from mining is upgraded.

Reclamation

The Panel's estimate for the state of future reclamation is that the reclaimed area as a share of the total disrupted area will remain more or less constant for the near future (Figure 2.12). The rate of reclamation will pick up significantly once the oldest mines are closed and the first of the younger mines pass the point of accelerated reclamation. Over the next century, the rate of reclamation (and certification) will need to exceed disturbance, so that nearly all the land disturbed by mining in the region can be returned to the provincial government in accordance with the *Environmental Protection and Enhancement Act* (Alberta Government, 2014c).



Data Source: Calculations use data from ESRD (2014a)

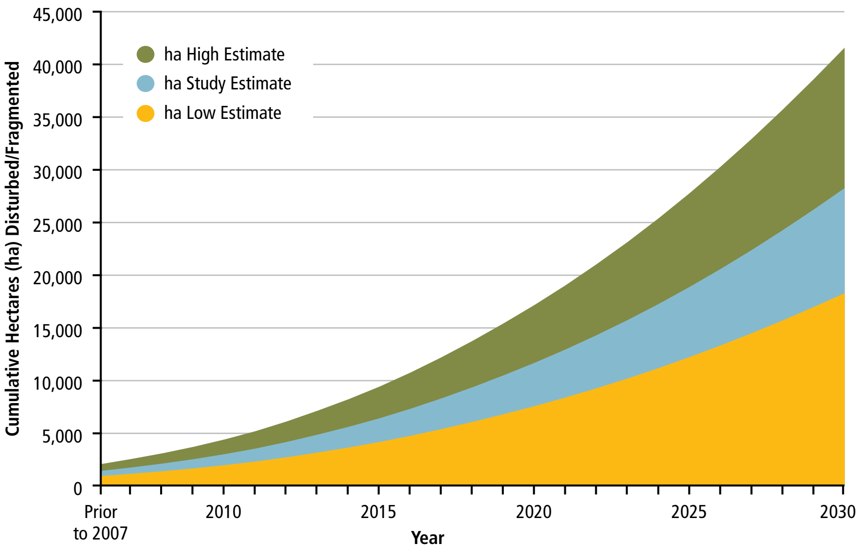
Figure 2.12

Land Reclaimed or Under Active Reclamation

The blue area shows the amount of land that is either permanently reclaimed or in some stage of reclamation (i.e., soils have been reclaimed). Red indicates the amount of land that is available for reclamation but has not yet been reclaimed. The green line shows reclaimed land as a percentage of the total mine footprint. While the absolute amount of reclaimed land has increased steadily, its proportion of the total footprint has decreased slightly, mainly as a consequence of recent mine expansions.

2.6.2 In Situ Production

At the time of writing this report, no data were available on the amount of land currently disturbed or fragmented by in situ production. Jordaan *et al.* (2009) have developed a range of intensity metrics based on the review of literature, environmental impact assessments, and input from a workshop held by the Cumulative Environmental Management Association (CEMA) in 2008. The amount of land affected per barrel of bitumen produced ranges from 0.011 to 0.025 m^2. An estimated value of 0.017 m^2 per barrel of bitumen was derived for the study region. Much of the variation depends on the shadow or buffer effects: how far the cutline/road/pipeline/facility footprint extends into the forest beyond the actual cleared areas. Linear features also provide access for new recreational land uses (e.g., hunting, skidoo, all-terrain vehicles) that further disturb ecosystems and compete with indigenous land uses. Figure 2.13 provides estimates based on these intensities. In 2030, the cumulative land footprint of expanded in situ production is estimated at 18,000 to 42,000 hectares (ha).



Data Source: Calculations use data from Jordaan *et al.* (2009) and bitumen production forecasts from CAPP (2014a)

Figure 2.13

Land Disturbed or Fragmented Through In Situ Operations

The figure shows the growth of disturbed land associated with growth of in situ production. By 2030, the cumulative land footprint of expanded in situ production is estimated to range between 18,000 and 42,000 hectares.

2.6.3 Upgrading

Upgrading produces petroleum coke and elemental sulphur, which are currently stored on land as solid waste, thereby contributing to the land footprint. Sulphur stockpiles also represent a fire hazard that could lead to high levels of air emissions and water contamination.

Coke, similar in many ways to coal, can be used as an energy source in upgrading and in situ steam generation using a gasification process. This process, however, leads to higher emissions of CO_2, sulphur, and other air pollutants. Due to current low prices for natural gas, this use is not economically viable at the moment. Coke can also be used as material in reclamation to accelerate the establishment of trafficable surfaces and research is ongoing in the use of coke to treat process-affected water (Zubot *et al.*, 2012). However, current regulation, under which coke is considered an energy resource, requires that coke deposits remain accessible for potential future use. The limited use of coke has led to coke stockpiles of some 76 million tonnes by 2012 (AER, 2013f). Coke stockpiles can be a source of fugitive dust emissions and air quality impacts from coke fires (an issue historically). Seepage through the coke deposits may present a risk to water quality.

The market value of elemental sulphur is generally lower than the cost of transportation to the nearest market, leading to growing stockpiles of sulphur near upgrading operations reaching close to 10 million tonnes in 2013 (AER, 2015). There is a risk of sulphur ignition that could lead to the release of dangerous SO_2 into the atmosphere and water contamination. As a result, sulphur blocks are closely monitored. Sulphur blocks also produce very low pH waters, which need to be carefully controlled on site (Birkham *et al.*, 2010).

2.7 CONCLUSIONS

Current oil sands extraction and processing methods result in a wide range of environmental impacts, some of which may cross environmental thresholds. Good management, regulation, and development and implementation of new technologies are therefore needed to manage impacts.

Based on current forecasts of future oil sands production and assuming current technology use, the industry's contribution to the environmental footprint will increase significantly in several areas as oil production expands. The effects are not always linear. Estimates are also subject to different degrees of uncertainty given limited knowledge about the fate of some pollutants, responses of the affected ecosystems, and technological or geological constraints faced by oil sands operators.

The most significant areas are GHG emissions and tailings and related land disturbances. Assuming no major expansion of upgrading in Canada, GHG emissions are estimated, with high certainty, to approximately double by 2025 and continue to grow proportionally with bitumen expansion. The future trajectory of tailings volumes will be affected by operators' success in implementing new and existing technologies at commercial scale to comply with the Alberta Government's Tailings Management Framework. Table 2.3 summarizes the emissions and resource use that are included in the definition of the environmental footprint of oil sands used in the remainder of this report.

Table 2.3

Summary of the Environmental Footprint of Oil Sands Production

Area	Emissions/ Resource Use	Contribution to Environmental Footprint	Expected Future Emissions Under Existing Conditions
GHG	GHG emissions	Contribution to global warming potential	Emissions to increase by 100% by 2025 under 2014 production estimates
Air	SO_x emissions	Low impact at current emission levels	Absolute levels stable to slight decline Intensity levels on fast decline (unless new upgraders are built)
	NO_x emissions	Potential for nitrogen fertilization leading to change (+/-) in ecosystem function, possible eutrophication	Moderate to large absolute increase, followed by stabilization Intensity levels to decline continuously (possibly as a step function as lower NO_x engines are introduced over time)
	PAH emissions	Possible impacts in 30 to 40 km range of emission sources	Moderate increase expected (based on industry projections)
	VOC emissions (fugitive emissions of organic chemicals usually in complex mixtures in air, e.g., pentane, butane, acetone)	Potential risk to animal and human health from some compounds	N/A
	Dust/particulate emissions	Transfer off-site of trace elements/PAH in coarse (dust) fugitive emissions Burial of reclaimed areas next to tailings sand beaches	For coarse ($PM_{2.5\text{-}10}$ μm) and larger-sized PM — a slight to moderate increase as a result of expanded mining activity, depending on degree of off-road hauling and use of dust suppression For fine (less than $PM_{2.5}$ μm) — a slight to moderate increase as a result of expanded mining activity, depending on degree of off-road hauling and use of dust suppression
	Trace elements from fixed and mobile emissions sources (mercury, cadmium, nickel, vanadium, etc.)	Transfer off-site, current levels with range of those measured elsewhere	Small absolute increase expected as consequence of expanded hauling activity in mining
	Odour emissions	Nuisance and potential risk to human health; as yet not quantified	N/A

continued on next page

Area	Emissions/ Resource Use	Contribution to Environmental Footprint	Expected Future Emissions Under Existing Conditions
Water	Water withdrawal (surface water and groundwater)	Potential for seasonal shortages and impacts on aquatic environments Changes in hydraulic regime of wetlands near mines Water diversion and re-establishment of watercourses affecting local riparian and wetland ecosystems	Without further improvements in freshwater use intensity, freshwater withdrawals could more than double by 2030 as a result of expanded production
	Release of process-affected water (intentional and unintentional) from surface mines	Surface water quality in reclaimed wetlands and streams Surface water quality in end-pit lakes Surface water quality in receiving streams Groundwater contamination	Under Alberta's *Environmental Protection and Enhancement Act* (1993), approvals require no releasing of process-affected water; evidence of tailings seepage into aquifers suggests that minor water contamination will continue
	Release of bitumen and other contaminants from the in situ reservoir	Groundwater, surface water, or soil contamination	N/A
Tailings	Tailings storage facilities	Risk of catastrophic breach and release of contents Risk to waterfowl and wildlife Fugitive emissions (gas and dust)	N/A
	Fluid fine tailings	Major reclamation challenges — delays and high costs in stabilization and reclamation (e.g., risks associated with permanent storage in end-pit lakes)	Expected to remain at current volumes or above Intensity levels expected to decrease with use of new technologies

continued on next page

Area	Emissions/ Resource Use	Contribution to Environmental Footprint	Expected Future Emissions Under Existing Conditions
Land	Physical disturbance by surface mining during active operations	Habitat destruction and loss of biodiversity Temporary loss of land use (many decades), risk of permanent change in land use Surface water diversions and re-establishment Regional impacts on wildlife	Absolute levels expected to increase in proportion to growth in new projects Intensity levels may increase or decrease with new tailings technologies
	Physical disturbance by in situ operations and infrastructure	Habitat deterioration and loss of biodiversity Loss of land use Surface water disruption Regional impacts on wildlife	Absolute levels expected to increase in proportion to growth in new projects Intensity may increase or decrease with well spacing
	Reservoir leakage	Accidental release of steam/bitumen/solvent	N/A

3

Surface Mining and Extraction Technologies

- Technologies to Reduce GHG and Air Emissions
- Technologies to Reduce Water Impacts
- Technologies to Reduce Tailings Volume and Impacts
- Approaches to Reduce Land Impacts
- Conclusions

3 Surface Mining and Extraction Technologies

Key Findings

Though full-scale adoption of mobile mining, including mobile crushing units and at-face slurrying and digestion, may be limited to new mines, replacing or retrofitting haul trucks and shovels over time can be done for existing mines. Both offer significant reductions in NO_x emissions but only modest reductions in GHG emissions. Dust suppression technologies are effective in containing many air pollutants to mine sites.

Solvent-based extraction technologies are promising for water use reduction and elimination of fluid fine tailings production. They are still in an early stage of development, with little to no information available on performance in large-scale operations, costs, or environmental impacts from solvent release.

Preliminary evidence suggests that water treatment technologies, if scaled up, have the potential to treat process-affected water for discharge. This requires overcoming several technical challenges and establishing discharge standards.

Operators are piloting a range of technologies to reduce the volume of and to remediate tailings. While no single "silver bullet" technology currently exists, this suite of technologies — if used together and tailored for particular geological and geotechnical conditions and tailings streams — may constitute a "silver suite" of tailings management solutions that could provide the path to acceptable and timely reclamation.

There is an opportunity to keep froth treatment tailings separate from the other more voluminous tailings streams and to effectively treat this stream to remove residual solvents. This would reduce fugitive emissions from tailings ponds such as VOCs and methane, and help facilitate their reclamation.

Over the past 50 years, the performance of surface mining has been improved by important technological advances like slurry hydrotransport, the shift to shovel/haul trucks, and advances in bitumen extraction. Despite these advances, environmental challenges remain. These are broadly related to emissions and energy use associated with mining activities and to the water-based extraction process, which not only requires large amounts of water, but also results in large quantities of tailings stored in tailings ponds and in the reclaimed landscapes.

The technologies reviewed in this chapter can help address these broad challenges for new mines and, where retrofitting is practical, for existing mines. Taken together, the technologies can increase the efficiency of energy use in mining and transportation of bitumen, minimize freshwater withdrawals from local rivers and creeks, more effectively treat process-affected water, reduce the volume and improve the composition of tailings, and reduce mine sprawl and speed reclamation.

3.1 TECHNOLOGIES TO REDUCE GHG AND AIR EMISSIONS

The mining and transportation of oil sands ore by haul truck are the main sources of GHG and NO_x emissions in surface mining. Two broad classes of technologies can reduce these emissions: (i) mobile mining operations, and (ii) application of new engine technologies for haul trucks. Though full-scale adoption of mobile mining may be limited to new mines, replacing or retrofitting haul trucks and shovels over time can be done for existing mines. Both offer significant reductions in NO_x emissions but only modest reductions in GHG emissions. A third class of technologies, those that suppress dust from mining activity, can help limit the dispersion of some air pollutants, including trace elements and particulates.

3.1.1 Mobile Mining Operations

The greatest reduction in GHG and NO_x emissions would be achieved if crushing and slurrying were done at the mine face. Two promising technologies of this sort are mobile crushing units and mobile at-face slurrying and digestion.

Mobile Crushing Units

With truck and shovel technology, a shovel is used to dig out oil sands ore from the mine and load it into large haul trucks, which then transport it to a crusher.[16] The crusher initiates the processing of the ore by breaking it into smaller lumps. These lumps are then typically deposited on a conveyor, which transports it to the next processing and bitumen extraction facility (see Figure 2.1). When a mobile crushing system is used, the shovel loads the bitumen directly into a mobile crusher located at the mine face, which deposits the crushed bitumen onto a mobile conveyor for further processing.

16 A similar volume of overburden and interburden material is also moved by truck and shovel operations and used to build dumps and dykes. This waste stream is less amenable to mobile mining operations due to the large diffuse deposition areas.

Mobile crushing systems for use in the oil sands have been designed to match the capacity of the large shovels that feed the unit with bitumen ore; new designs allow for higher capacity units (Cook, 2007). Several major oil sands operators use mobile crushing units. Albian Sands, for example, has been using a semi-mobile crushing plant since 2002 that can process 14,000 tonnes of bitumen per hour. Syncrude operates in-pit mobile crushing with slurry equipment, which allows bitumen to be carried by a hydrotransport system out of the mine for further processing.

One of the benefits of mobile crushing systems is that it obviates the need for trucks, thereby reducing GHG and NO_x emissions, resulting in reduced haul road requirements for the large haul truck fleets. While mobile crushing units provide opportunities for reduced energy and emissions, the Panel understands them to have less mining flexibility and have more downtime (less availability) than the truck fleet, which can restrict their uses. Another opportunity is the removal and transport of overburden and reclamation material using mobile crushers and conveyor. Spreaders or stackers can be used for placement in the depositional areas as is common in brown coal mining.

Mobile At-Face Slurrying and Digestion

To reduce the energy use associated with transporting materials, the oil sands industry has been developing methods for rejecting the coarse sands as they are mined, thereby avoiding having to transport them out of the mine (RSC, 2010). A mobile at-face slurrying and digestion system, for example, would extract the bitumen from the crushed ore and reject a sand-tailings slurry right at the mine face. The bitumen (with water and some fines) would then be sent to a secondary fixed extraction plant and the coarse sand tailings would be deposited nearby, perhaps after dewatering to improve its geotechnical and depositional properties.

There are numerous potential benefits to this technology. The rejected sand would amount to about 60 to 70% of the ore stream and transport distances for this waste could be reduced by perhaps an order of magnitude, a major energy savings (RSC, 2010). Replacing haul trucks with more energy-friendly slurry hydrotransport would reduce not only the energy cost, but also GHG and NO_x emissions related to the trucks' diesel consumption. Hydrotransport of fine solids slurry after rejecting coarse solids at the mine face (on site) would also lower energy and maintenance costs related to wear of pipes and pumps by transporting slurry at a lower-flowing velocity (RSC, 2010).

There remain some significant economic and mine planning hurdles to mobile at-face slurry technology. Technologies that would improve the properties of the sand-tailings slurry to allow it to be safely deposited adjacent to the mine face would be a great enabler for this at-face technology.

3.1.2 Application of New Engine Technologies for Haul Trucks

Similar to other surface mining operations, oil sands surface mining is dependent on large diesel-powered equipment including shovels, haul trucks, graders, and loaders. The most significant are the haul trucks, which typically run for more than 6,000 hours per year and burn over 1 million litres of diesel fuel (M.J. Bradley & Associates, 2008). These trucks, which have power ratings of between 2,400 and 3,500 horsepower, consume more than 75% of the diesel fuel used in surface mining operations, and account for the majority of diesel emissions. NO_x emissions from this truck fleet totalled over 21,000 tonnes in 2012 (Watson *et al.*, 2012, 2013b). Reductions in GHG and NO_x emissions can be achieved with new heavy haul engine technologies, autonomous haul trucks, and retrofitting trucks and shovels.

New Heavy Hauler Engine Technologies

In 2008, 200 heavy haul (380 to 400 tonnes) mining trucks operated in the oil sands (M.J. Bradley & Associates, 2008). This number has been predicted to reach 650 units in 2015 given recently approved and applied for mine projects (M.J. Bradley & Associates, 2008). The current fleet uses U.S. EPA Tier 1 engine technology with the exception of one operator that now uses Tier 2 engine haul trucks.[17] Operators will have the opportunity to upgrade as engines are replaced as per normal maintenance schedule. On-board measurement of "real-world" emissions from four Tier 1 engines undertaking a range of operations without a load cycle indicates that Tier 1 engines met Tier 2 and 4 limits for carbon monoxide and Tier 1 limits for non-methane hydrocarbons, NO_x, and $PM_{2.5}$. Emissions exceeded the Tier 2 limit for the sum of non-methane hydrocarbons and NO_x, but were lower than the Tier 2 limit for $PM_{2.5}$. Emissions met the Tier 4 limit for non-methane hydrocarbons, but exceeded those for NO_x and non-methane hydrocarbons (M.J. Bradley & Associates, 2008).

Emission estimates or factors (EFs) for non-road engines are calculated based on carbon mass balance (Watson *et al.*, 2012, 2013b). CO_2 is the largest combustion product from the haul trucks (greater than 3,100 g/kg fuel), NO_x emissions are less than 36 g/kg fuel, and methane, SO_2, H_2S, ammonia, and $PM_{2.5}$ are all low. EFs have also been determined for other pollutants such as organic/elemental carbon, halocarbons, alkanes, and PACs. While SO_2 emissions to

17 For a discussion of Tier 1-4 EPA engine technology classifications, see M.J. Bradley & Associates (2008).

air have decreased from some 450 tonnes/day in the 1990s to an expected 160 tonnes/day by 2015 (Clair & Davies, 2015), emissions of NO_x have been increasing. Tier 2 engines are required to achieve significant reductions in emissions, particularly NO_x. On-board testing in "real-world" conditions of these engines now operating in the region will determine if the 30 to 50% reduction in NO_x will be realized under operating conditions, and not just demonstrated in static certification testing (Watson *et al.*, 2012, 2013b).

Autonomous Haul Trucks

Autonomous (and semi-autonomous) haul trucks (AHTs) operated by specialized computer systems can potentially replace human-operated trucks, reducing fuel consumption (and thus GHG emissions) by around 15% (Parreira & Meech, 2012). Simulations suggest that AHTs can also have positive impacts on productivity, safety, maintenance, labour costs, cycle time, and tire wear (Parreira & Meech, 2012). Rio Tinto, BHP Billiton, Fortescue, and Codelco use AHTs in mining operations around the world. In Fall 2013, Suncor began field tests at two sites.

Retrofitting Trucks

The literature describes a number of retrofit technologies produced by a range of firms. M.J. Bradley & Associates (2008), for example, reviews diesel oxidation catalysts and diesel particulate filters for reduction of PM, selective catalytic reduction, NO_x reduction catalyst, and exhaust gas recirculation for NO_x reduction. The authors argue that nearly all these technologies can be applied to large mining trucks and could provide significant and cost-effective reductions of NO_x and PM from the oil sands mining truck fleet. According to simulations, the net present value of total costs (capital and ongoing operating costs) ranged from $113 million to $181 million, with the average cost of emissions reduction ranging from $1,600/tonne to $3,400/tonne for NO_x and $9,400/tonne to $30,000/tonne for PM. In comparison, the U.S. EPA estimates that emissions reductions through retrofit of smaller non-road diesel engines will cost $2,100 to $21,000/tonne for NO_x reductions and $21,000 to $87,000/tonne for PM reductions (M.J. Bradley & Associates, 2008).

3.1.3 Dust Suppression Technologies

As noted in Chapter 2, extended exposure to fugitive dust can cause adverse environmental and health effects. Fugitive dust includes small particles that become airborne from open, uncontrolled sources such as unpaved and paved roads, mining pits, and tailings beaches. It has been recently identified as the dominant vector for the transport and deposition of trace elements and PACs within 20 to 30 km of mining/upgrading operations. The first comprehensive regional dust emissions source characterization study using a portable in situ wind erosion laboratory has determined size fractionation, chemical speciation, and travel distance for 27 sites. Flux to atmosphere rates from mine haul roads are two to four orders of magnitude greater than highway shoulders at various wind speeds (Watson *et al.*, 2014).

The literature identifies two effective solutions for suppressing dust: (i) surface watering reduces dust emissions from mine haul roads by 50 to 99%, and (ii) minimizing surface disturbance limits transfer of potential contaminants to the landscape surrounding mine operations (Watson *et al.*, 2014). In 2012, Suncor and General Electric successfully tested and operationalized a non-corrosive, organic dust suppressant on gravel roads to in situ facilities at MacKay River. This achieved a 75% reduction in respirable dust particulates and an 85% reduction in water used for road surface watering (i.e., 4,000 litres annually per kilometre of road) (Suncor Energy Inc., 2014b).

3.2 TECHNOLOGIES TO REDUCE WATER IMPACTS

At surface mining operations, water impacts and tailings are interconnected (see Chapter 2). The Lower Athabasca River Water Management Framework currently ensures that withdrawals never exceed 15% of natural river flow and that a maximum of 3% of annual flow is withdrawn (Alberta Environment & Fisheries and Oceans Canada, 2007). Although approximately 80 to 85% of water is recycled, a significant amount of water is used in the Clark Hot Water Extraction Process (RSC, 2010). There are also limits to improving water use efficiency by recycling process-affected water. Repeated extraction cycles are found to contribute to a decline in water quality, which disrupt the extraction process by way of scaling, fouling, increased corrosivity, and interference with extraction chemistry (Kasperski, 2003; Rogers, 2004; Quagraine *et al.*, 2005; Allen, 2008b). Consideration of process-affected water quality in the pores of sand and fine tailings is also important as this water will flow eventually through the reconstructed creeks, wetlands, and end-pit lakes in the reclaimed landscapes, and be improved by either passive or active water treatment before discharge to the natural environment. Large quantities of process-affected water are also stored in tailings ponds and will need to be dealt with (through reuse elsewhere or by treatment) at the time of mine closure.

Given these considerations, the Panel identified three major challenges to reducing water impacts and the volume and composition of tailings. First, the recovery rate of bitumen is currently around 90% (Nikakhtari *et al.*, 2013).

However, as reservoir quality declines, recovery rates are likely to decline towards 80%,[18] which implies a larger amount of fine clays in tailings streams and a significantly greater loss of bitumen to tailings. Second, reducing the volume of fluid tailings requires dewatering tailings to a semi-solid state (nominally about 70 to 80% solids by mass; see Section 3.3). This was highlighted as an outstanding technical and commercial challenge by the Consortium of Oil Sands Tailings Management Consultants (CTMC 2012a, 2012b). Third, at present, water treatment guidelines and discharge standards do not exist for process-affected water. While the oil sands industry and its regulators have touted their lack of water discharge as a positive aspect of their processes (ERCB, 2011), the need for discharge of suitably treated process-affected water, as is done in just about all other industries, is becoming increasingly apparent. In the absence of discharge standards, process-affected water will continue to accumulate on site (Younger *et al.*, 2002; Küpper, 2013), contributing to sprawl, tailings, and water containment costs, increasing the risk of a tailings dam breach, and delaying reclamation. The Panel believes that discharge standards are ultimately required for improved tailings management. Experience from other surface mining operations (e.g., Directive 019 in Quebec) can help in this respect. Despite these challenges, technologies do exist for minimizing freshwater withdrawals and treating process-affected water for recycled use or discharge. These are described below.

3.2.1 Reducing Freshwater Withdrawals and the Production of Fluid Fine Tailings: Solvent Extraction Technologies

The greatest reduction in freshwater withdrawals and fluid fine tailings production would be achieved if less water were used to separate bitumen from the oil sands. This would have the added benefit of reducing the growth of tailings ponds and speeding the reclamation of mine sites. As CTMC (2012a, 2012b) argues, solvent-based extraction is one of the few technologies that would fundamentally change the nature of tailings management in the oil sands. Solvents have the added benefit of potentially reducing energy use. These technologies, however, are still at an early stage of development, with little to no information available on performance in large-scale operations, costs, or environmental impacts from solvent release.

Research on solvent-based extraction has been undertaken since the early 1960s with a large number of patents related to bitumen extraction using organic solvents. The Panel notes that among others, Shell Energy, Syncrude, Imperial

18 As reservoir quality, x, declines (as measured by the average weight per cent bitumen content of as-mined ore), the recovery rate is governed by the following quadratic equation for $x<11$: $-202.7 + 54.1x - 2.5x^2$. Current recovery rates of 90% are near the upper limit ($x>11$) and estimated recovery rates of 80% are when x is between 8 and 9% (based on Panel calculations).

Oil, and Epic Oil Extractors have been active in pursuing these technologies, with the emphasis on the use of light solvents such as pentane or cyclohexane. When paraffinic solvents such as pentane are used, asphaltenes are precipitated; when solvents with cyclic compounds or aromatic content are used, asphaltenes precipitation is avoided.

In a typical extraction process using hydrocarbons, solvent is added to the ore to dissolve the bitumen, leaving behind the sand, clay, and moisture (Sparks *et al.*, 1992; Wu & Dabros, 2012; Nikakhtari *et al.*, 2013). The moisture in the ore, possibly augmented with a small amount of water, binds the fine clay particles to the sand. An alternative approach is to use ionic liquids or other non-volatile organic liquids to separate the bitumen from the sand and clay in the ore (Painter *et al.*, 2010; Holland *et al.*, 2010). In the approach taken by Painter *et al.* (2010), the bitumen is dissolved by a hydrocarbon solvent such as toluene, and the sand and clay stay in the ionic liquid. The ionic liquid is recovered by water washing. The switchable solvent approach used by Holland *et al.* (2010) removes the bitumen, leaving clean sand and clay, and the solvent is separated from the bitumen with a wash of carbonated water.

In any solvent extraction process, the solvent needs to be removed from the solids contained in the oil sands ore that is being processed. For hydrocarbon solvents, such as cyclohexane, some become associated with the clays and fine solids, thereby leading to solvent losses (Nikakhtari *et al.*, 2013). Solvent losses are correlated with the solvent vapour pressure with a lower solvent vapour pressure leading to a higher solvent loss. Moreover, the extracted bitumen contains solids that need to be removed. In the case of ionic liquids, the specific issues of solvent recovery depend on the specifics of the process. Ultimately, with the use of solvent for bitumen recovery, new environmental issues arise in terms of solvent release to the atmosphere (for light hydrocarbons) and returning solids contaminated with solvents to the mine pit (for all solvent-based technologies). In every case, the fate of the fine particles from the oil sands ore is of paramount importance. Passage of fine solids into the bitumen is undesirable (Nikakhtari *et al.*, 2014), as is passage of fine solids into water wash solutions.

The Panel notes that while these solvent-based technologies are promising for reductions in freshwater withdrawals and fluid fine tailings production, they are only attractive to new mines or those undergoing major expansions (due to the existing capital invested in aqueous extraction). This situation fundamentally limits their ability to reduce the total environmental footprint of surface mining. All of these technologies offer higher recovery of bitumen from a range of ores than the existing water-based technology, but the amounts of residual solvents and contamination of the bitumen by fine solids have not been defined for large-scale operation. These technologies are also in an early stage of development, with little to no information available on cost or environmental impact and likely considerable hurdles to overcome (CTMC, 2012a, 2012b; Nikakhtari *et al.*, 2013).

3.2.2 Recycling Water and Treating Process-Affected Water for Discharge

The water used in extraction of bitumen from mined oil sands can be recycled for reuse without water treatment, as long as the content of fine solids is low and it has acceptable levels of dissolved salts. Water withdrawal from the river is required because of the steadily accumulating water in the tailings pore spaces, along with the smaller volume required for process steam and power generation. When a mine closes and tailings are no longer being generated, the released water needs to be treated as part of the landscape reclamation. For some mine plans, it may be advantageous to treat and discharge excess process-affected water during operations to reduce storage requirements and facilitate faster reclamation.

Development of new technologies is needed to treat process-affected water for discharge under future regulations (see Chapter 7). The Panel identified six classes of emerging technologies in the literature. These are summarized in Table 3.1 and discussed in turn. The evidence — from laboratory studies, pilot studies, and commercial operations — suggests that, if scaled up, these technologies have the potential to treat process-affected water, making water discharge a reality. Nonetheless, a series of challenges makes this difficult, including the toxicity of discharge and the volume (flow rate) to be treated. Effective treatment will likely involve a combination of techniques, rather than just a single solution.

Adsorption

Adsorbents such as activated carbon and biochar, natural organic matter, zeolites, clays, and synthetic polymers are used to remove many pollutants in process-affected water, including soluble organic carbon compounds, oil and grease, and heavy metals. There are potential applications in de-oiling and removal of naphthenic acid/other organics from tailings water. Adsorbents have a low overall environmental impact, with minimal waste production (Allen, 2008a, 2008b).

Table 3.1
Summary of Water Treatment Technologies

Technology	Target Pollutant	Challenges
Adsorption	Bitumen, PAHs, trace metals	Incomplete removal; cleaning and regeneration costs; low adsorptive capacity; fouling; acidification required for NAs Affected by ion strength
Micro- and Ultrafiltration	Bitumen, suspended solids	Disposal of concentrate; fouling; durability
Nanofiltration and Reverse Osmosis	NAs, PAHs, hardness	Brine disposal; replacement costs; fouling; high flow rates
Biological Treatments	Bitumen, NAs, PAHs, ammonium	Incomplete removal; sludge disposal; feed water toxicity
Advanced Oxidation	NAs, PAHs, ammonium	Incomplete removal; high energy costs; radical scavengers; by-products
Treatment Wetlands	Bitumen, NAs, PAHs, ammonium, sulphate, trace metals	Feed water toxicity; flow capacity; cold weather; accumulation of toxicants

Allen (2008a, 2008b)

Micro- and Ultrafiltration

Micro- and ultrafiltration use pressure-driven membranes to reject particles from between 0.1 and 0.01 micrometres. These have been demonstrated in lab and pilot testing to reject 90% of oil with permeate concentrations of less than 20 parts per million. Fouling and membrane durability present challenges for these processes, and their economic viability is uncertain (Allen, 2008a, 2008b).

Nanofiltration and Reverse Osmosis

Nanofiltration membranes reject divalent ions, dissolved organic matter, pesticides, and other macromolecules to varying degrees (rejection rates vary from 15 to >90%). They are not effective for low molecular weight and volatile organics. Nanofiltration has potential applications for partial demineralization, softening, and removal of soluble organic compounds from process-affected water. While its technological viability has been demonstrated in the lab, scalability and economic viability are unclear (Allen, 2008a, 2008b).

Reverse osmosis forces process-affected water against a concentration gradient through a semi-permeable membrane. Pilot studies have converted process-affected water to fresh water for agricultural and potable use with reverse osmosis. Fouling, biofouling, and low rejection rates are challenges for volatile organics. Electrodialysis passes process-affected water through an electrolytic cell and several successful lab- and pilot-scale demonstrations have shown that electrodialysis can remove oil, solids, salts, and soluble organics (Allen, 2008a, 2008b).

Biological Treatments

Biological treatment processes (bioremediation) use microorganisms to remove organic pollutants from process-affected water, both in low-rate (e.g., stabilization ponds and lagoons) and high-rate processes (e.g., activated sludge, trickling filters, rotating biocontractors). While many biological treatments have been tested extensively for removal of organic carbon and nitrogen compounds, the evidence is mixed:

- Tellez *et al.* (2002) report removal rates of 98 to 99% for total hydrocarbons from petroleum oilfield water after microbes acclimatize to saline conditions (activated sludge).
- Hansen and Davies (1994) report removal rates of 14 to 30% and 70 to 73% for phenols and total organics from petroleum oilfield water, respectively (activated sludge).
- Doran *et al.* (1998) report removal rates of 15 to 20% for total organic compounds from petroleum oilfield water in a trickling filter.

Advanced Oxidation

Advanced oxidation uses ionic or radical reactions involving an oxidant compound (e.g., chlorine, hydrogen peroxide, O_3, permanganate). Oxidation is often used for compounds that are unsuited for biological treatment because of their toxicity or recalcitrant nature. Two types of oxidation processes have been shown to degrade pollutants though both have significant energy and operating costs. Photocatalytic oxidation has demonstrated removal rates of 40 and 59% for total organic compounds and ammonia, respectively. Sonochemical oxidation has been shown to break or destroy particles or molecules. This is achieved by applying ultrasound to process-affected water, leading to the formation and collapse of bubbles, which in turn produces cavities (cavitation) of high temperature and pressure (Allen, 2008a, 2008b).

Treatment Wetlands

Wetlands have been constructed to treat process-affected water, contaminated groundwater, and waste streams from refineries and petrochemical plants (Knight *et al.*, 1999). These constructed wetlands involve: surface flow wetlands, which are open-water, gravel substrate systems dominated by common reeds, cattails, and bulrushes; and subsurface flow wetlands to which process-affected water is directed through a gravel substrate-rooting zone. In this zone, gas exchange, nutrient uptake, microbial activity, and a variable redox environment promote the removal of contaminants. Contaminant removal processes in wetlands include sedimentation, adsorption, de-nitrification, photo-oxidation, plant uptake, and volatilization to the atmosphere (Allen, 2008a, 2008b). A constructed fen is depicted in Figure 3.1.

Figure 3.1
A Constructed Fen at Syncrude

Current research is focused on hydraulic design tools, area-based removal coefficients, and biogeochemical indicators (Quagraine *et al.*, 2005; Allen, 2008b). Wetlands have proven to be effective in removing contaminants in industrial waste water and petroleum oilfield water, but various pilot- and full-scale studies have shown variable treatment performance: removal rates range from 10 to 94% depending on organic compound type. The use of end-pit lakes as passive bioreactors for water treatment is discussed in Section 3.3.4.

3.3 TECHNOLOGIES TO REDUCE TAILINGS VOLUME AND IMPACTS

Extensive R&D on tailings, including significant financial investments and dozens of large field pilots, has been conducted since the 1960s (RSC, 2010; CTMC, 2012a, 2012b; Fair, 2013; McKenna *et al.*, 2013; Sobkowicz, 2013; Read, 2014). Tailings ponds, however, remain an outstanding environmental and financial liability, as highlighted in Chapter 2. Concerns have also been raised about the accumulation of fluid fine tailings, seepage of process-affected water from tailings ponds and the surrounding dykes,[19] and the risk of a dyke breach (Morgenstern, 2010, 2012; Küpper, 2013). Similar concerns also exist for other types of mining operations (Vick, 1990; Aubertin & Chapuis, 1991; Aubertin *et al.*, 2002b, 2011; James *et al.*, 2013; Canadian Dam Association, 2014). These issues are discussed in Section 3.3.5.

Recent literature (CTMC, 2012a, 2012b; OSTC & COSIA, 2012) identifies an extensive range of tailings technologies that have been implemented or are being tested to reduce tailings pond volume by increasing the degree of consolidating (dewatering) of mature fine tailings. Each of these technologies is best tailored to particular geological and geotechnical conditions and tailings streams (i.e., thin-layered fines-dominated deposits, deep fines-dominated deposits, or fines-enriched sands) (OSTC & COSIA, 2012). This section discusses eight classes of technologies that build on the literature noted above: thin-lift dewatering (TLD) of in-line flocculated mature fine tailings, centrifugation of flocculated mature fine tailings, thin-lift freeze-thaw, thickened tailings, accelerated dewatering, filtered tailings, composite tailings, and end-pit lakes. Despite this range of technologies, there is currently no single breakthrough or "silver bullet" technology that can reduce the volume and improve the consolidation of fluid fine tailings. However, a suite of technologies — if used together and tailored for particular geological and geotechnical conditions and tailings streams — may constitute a "silver suite" of tailings management solutions that could provide the path to acceptable and timely reclamation (Read, 2014).

Most oil sands operators currently deliver coarse and fluid fine tailings (from primary and secondary extraction) and froth treatment tailings (from the froth cleaning step) into tailings ponds (Figure 2.9). As noted in Chapter 2, froth treatment tailings are a relatively small stream (only 2 to 4% of the total volume of tailings produced) but have some challenging properties (RSC, 2010; Czarnecki *et al.*, 2011). They contain residual solvents, either naphtha or

19 Oil sands generally refer to tailings containment structures as dykes (whereas others might use the term "dams" or "spilling dykes").

paraffin liquids, used to clean the bitumen. These hydrocarbons can migrate to the water table and are volatilized by microbial activity. The tailings also contain elevated levels of sulphide minerals, which can result in acidic run-off/seepage if the tailings are allowed to oxidize, and slight elevated levels of naturally occurring radioactive minerals (CTMC, 2012a, 2012b). Froth tailings are generally discharged into tailings ponds, partially mixing with the extraction tailings. Some froth tailings segregate upon deposition to form very weak deposits that are untrafficable and prone to post-reclamation settlement. This disposal method makes stabilization and reclamation of these areas of the tailings ponds much more challenging (Russell *et al.*, 2010).

The removal of the residual solvent in froth tailings streams, together with discharging these streams into dedicated engineered containment cells, is a better strategy. This, however, requires operators to keep the froth treatment tailings stream separate and treat it for return to the mine (Xu *et al.*, 2013a, 2013b) or to recover bitumen and metals (Moran *et al.*, 2013). Separation and effective treatment of froth tailings can address two important tailings problems: reduce fugitive emissions resulting from decomposing solvent that remains in froth tailings after treatment and keep out the most toxic elements that hinder the reclamation of tailings ponds. Since 2001 Titanium Corporation has been working on a technology to recover residual solvent, bitumen, and also heavy minerals (zircon and rutile). The work has included several pilots but the process has not been commercialized (Scott, 2006).

3.3.1 Thin-Layered Fines-Dominated Deposits

Thin-layered fines-dominated deposits are constructed with fine tailings streams that have sand-to-fines ratios of less than 1 and that are discharged subaerially into a disposal site in thin lifts that are typically 100 to 500 mm thick (OSTC & COSIA, 2012). This technology involves initial tailings dewatering through chemical and mechanical treatment, which is followed by atmospheric evaporation and freeze-thaw effects. It is being employed at a commercial scale using large areas to promote evaporation until the desired solids content is reached. These dewatered tailings can either be moved to a permanent disposal site or left in place as part of a multi-layer deposit. In some cases, the soft material can be placed in polders designed into overburden disposal structures. In other cases, they may be capped with tailings sand or petroleum coke (OSTC & COSIA, 2012).

Tailings technologies considered for thin-layered fines-dominated deposits are TLD of in-line flocculated mature fine tailings, centrifugation of flocculated mature fine tailings, and thin-lift freeze-thaw.

Thin-Lift Dewatering of In-Line Flocculated Mature Fine Tailings

The TLD process involves pumping or dredging out mature fine tailings from a tailings pond and injecting a flocculant into the tailings. The treated mixture is then discharged in thin lifts and into containment cells with a gently sloped base (OSTC & COSIA, 2012). On placement, there is an initial dewatering of the flocculated fine solids by run-off followed by evaporation under atmospheric conditions. This dewatering results in reduced water content and increased strength of the deposit. After the first layer dries, additional layers are deposited. The process has been shown to work best when there is an effective flocculation of mature fine tailings to allow for a satisfactory initial dewatering (OSTC & COSIA, 2012).

This technology is employed at mines internationally, though typically in more arid conditions. TLD is being used at Suncor as the central part of its tailings reduction efforts, and in atmospheric fines drying at the Shell Muskeg River Mine (CTMC, 2012a, 2012b). Highly capital, time, and land intensive, application of this technology is limited by relatively low potential evaporation rates, the properties of the flocculated tailings, and land availability. The technology is currently in the continuous improvement phase.

Centrifugation of Flocculated Mature Fine Tailings

This process involves pumping or dredging out mature fine tailings from a tailings pond, treating the fine tailings with a flocculant and then using a decanter centrifuge to separate the solids and water (OSTC & COSIA, 2012). The water ("centrate") is collected and pumped back into the tailings pond, and the solids ("cake"), typically of 50 to 55% solids concentration with roughly the consistency of toothpaste, are transported and discharged into a containment cell (OSTC & COSIA, 2012). The cake may be deposited in thin lifts (100 to 300 mm) or continuously poured to make a deep deposit where the material will consolidate over time.

Syncrude has piloted this process at its Mildred Lake operation with commercial-scale centrifuges and small test deposits. A $1.9-billion commercial-scale centrifuge plant is coming online in 2015 (Figure 3.2). Shell is in the final stages of commercial deployment and is building tailings centrifuges into its Jackpine Mine operations (COSIA, 2015).

Thin-Lift Freeze-Thaw

Thin-lift freeze-thaw technology consists of depositing mature fine tailings in multiple thin layers that are allowed to freeze in the winter and then thaw the following summer. The freezing cycle causes consolidated soil-like peds to form, developing a fissured structure throughout the deposit that quickly

Courtesy of Syncrude Canada Ltd.

Figure 3.2
A Centrifuge Plant Under Construction at Syncrude

drains when thawed (BGC Engineering Inc., 2010b). Fine tailings are deposited in cells in 5 to 15 cm thick layers and allowed to freeze. In this way, up to a total of about 4 to 5 m of material can be frozen over one winter season in the Athabasca Oil Sands Area but only about 2 to 3 m will thaw the next summer, which controls the design (Dawson *et al.*, 1999; Beier *et al.*, 2009). Several successful field pilots have been run.

Thin-lift freeze-thaw is perhaps best suited to processing modest volumes of fluid tailings left over in a tailings pond where the adjacent beach can be used for deposition and freezing. Large volumes can be processed given sufficient real estate and 10 to 20 years of operation. A more common variant of this approach, used at Shell and Suncor, is to allow a 1 to 2 m thick layer of fluid tailings that has been previously treated with polymer and perhaps undergone a drying cycle to freeze over the course of a winter, and then haul the frozen material in late winter to the final deposition site where it will thaw and further dewater (Caldwell *et al.*, 2014). Freeze-thaw cycling will also benefit the upper surface of most deep tailings deposits.

3.3.2 Deep Fines-Dominated Deposits

This deposit type consists of a fluid fine tailings stream discharged on a continuous basis into a deep disposal site, which accumulates a significant thickness over time (OSTC & COSIA, 2012). Initial water release is accomplished with a polymer flocculant. The balance of water release and volume reduction occurs through self-weight consolidation. This densification allows modest strength gains with time. After a sufficient surface crust has developed, the surface will be capped, typically with sand, to provide a trafficable layer, a weight to improve consolidation of the upper part of the deposit, a control of the water table and social moisture, and a substrate (OSTC & COSIA, 2012).

Deep fines-dominated deposits are generally favoured where in-pit area and volume are available (OSTC & COSIA, 2012). Thinner, out-of-pit deposits in a suitable containment structure may be necessary for new mine start-ups. Poulding of these deposits in out-of-pit sand storage and overburden storage areas may be employed if they provide long-term geotechnically secure containment. Consolidation rates for thick deposits are slow and post-reclamation settlements may be high (OSTC & COSIA, 2012). Syncrude plans several deep centrifuged tailings deposits at its Mildred Lake operation with the first starting in 2015 (COSIA, 2015).

Tailings technologies considered for deep fines-dominated deposits are thickened tailings, accelerated dewatering, and filtered tailings.

Thickened Tailings

With thickened tailings, extraction tailings are cycloned to remove much of the sand fraction (CTMC, 2012a, 2012b). The overflow (fines and water) stream, with a sand-to-fines ratio of approximately 1, is then fed into a thickener vessel with a polyacrylamide flocculant to cluster the fines into flocs. The operation of the thickener produces an underflow of thickened tailings with solids content in the range of 40 to 50% (CTMC, 2012a, 2012b). The thickened tailings are deposited into a deep cell for subsequent consolidation and capping.

While thickeners are used worldwide in mining operations, usually in processing a tailings feed with a relatively consistent density, gradation, and mineralogy (OSTC & COSIA, 2012), the complexity of oil sands tailings renders them much more difficult to process. Additional challenges to the thickening operations in oil sands tailings include the large-scale, high clay content, variability of fines and clay, and presence of residual bitumen (OSTC & COSIA, 2012).

Shell Canada operates thickeners at its Muskeg River and Jackpine mines, mostly to provide large quantities of warm recycle water for reuse in the extraction plant (CTMC, 2012b).

Accelerated Dewatering

This process, also known as rim ditch dewatering, involves a deep polymer-treated fine-rich tailings deposit with a perimeter ditch that is slowly deepened over time to enhance drainage and densification. Fine tailings are pumped from a tailings pond and treated with polymer to produce in-line thickened tailings, and deposited into an engineered cell (OSTC & COSIA, 2012). Surface water (from initial dewatering and precipitation/snowmelt) is decanted from the deposit. After the initial dewatering, and crusting of the surface due to evaporation and freeze-thaw, a shallow perimeter ditch is started (often only inches thick in the weak tailings) and deepened periodically. Over years, the rim ditch enhances the rate of crust formation on the tailings and drains away surface water. After many years, the deposit is capped and reclaimed.

This technology has been extensively employed in the Florida phosphate industry and is being tested at a large pilot scale at Syncrude with CanmetENERGY (OSTC & COSIA, 2012).

Filtered Tailings

Filtered tailings technology consists of filtering the whole (unaltered/coarse) tailings stream.[20] Filtration is a traditional method for solid-liquid separation and has been widely used in other industries (OSTC & COSIA, 2012). Filtering can be done with vacuum force or pressure, with horizontally or vertically stacked plate, drums, or horizontal belts — the most common filtration plant configurations. Pressure filtration can be carried out on a much wider spectrum of materials though vacuum belt filtration is probably the most logical for larger-scale operations (OSTC & COSIA, 2012). Xu *et al.* (2008) have conducted simple laboratory-scale filtration tests to evaluate the filterability of the oil sands tailings and to generate a parameter that can be used in filtration scale-up. This work highlights the impacts of fines content on filtration efficiency and the opportunity to use flocculants to improve filtration rates. Studies of commercialization of filtration technology at oil sands scales indicate the need for very large filtration plants involving high capital and operating costs. Despite the preliminary nature of these results, filtered tailings sand has a high value for an oil sands operation as it is easy to compact into dykes and dumps, has fewer ions to leach out due to its partial saturation at placement, and is relatively easy to reclaim.

20 Variations on this technology include addition of fines to tailings streams (as a fines disposal/enhanced capture method) or filtration of low fines sand streams to produce tailings sand suitable for trucking/conveying.

A variant on this technology, cross-flow filtration, where tailings are continuously filtered by pumping them through a porous pipe, is currently being studied by the University of Alberta (Zhang *et al.*, 2010). The Panel notes that a pilot is planned for 2015.

3.3.3 Fines-Enriched Sands

Fines-enriched sands are a tailings technology involving co-disposal of a coarse sand stream and a fines stream usually treated with a coagulant or flocculant. When the fines are derived from mature fine tailings, the process is referred to as composite tailings or consolidated tailings. When the fines are derived from a thickener underflow, it is referred to as non-segregated tailings (NST). The mix is designed to be non-segregating and forms a deposit that has relatively high hydraulic conductivity and low compressibility compared with fines-dominated materials (OSTC & COSIA, 2012). The deposits consolidate over several years to form a relatively dense (80% solids) sand-dominated deposit with fines in the pore spaces. Deposits are capped hydraulically with tailings sand soon after deposition but remain potentially mobile (liquefiable) in the long term (Morgenstern, 2010; OSTC & COSIA, 2012).

Tailings technologies considered for fines-enriched sands are composite tailings, spiked tailings, and enhanced beach capture.

Composite Tailings

Composite tailings are currently the process to form fines-enriched sand-tailings deposits. It consists of mixing coarse and fine tailings streams, with a coagulant, to produce a non-segregating, semi-solid deposit that can be capped for reclamation (OSTC & COSIA, 2012). The process is designed to contain an average of 20% fines (geotechnical fines content) at an initial 60% solids content. Hydrocycloning tailings from the extraction plant, which removes some fines and excess water, produces the sand stream. The cyclone sand underflow is combined with mature fine tailings harvested from a tailings pond. The slurry is treated with gypsum and discharged into a containment area where it releases additional water to the surface during settling and consolidation (OSTC & COSIA, 2012).

Composite tailings went into commercial production in the late 1990s at Syncrude and Suncor, and several large deposits have been created with some areas capped and reclaimed (Pollard *et al.*, 2012). Minimizing segregation of the deposits has proven difficult at field scales. At Suncor, this technology (outside specification) was capped using an innovative floating coke cover

(Wells *et al.*, 2010). The Panel notes, however, that Suncor has since moved away from this technology while Syncrude is commissioning its second composite tailings plant at its Aurora North Operation.

Spiked Tailings

Spiked tailings are similar to composite tailings, but involve adding a fines stream to a whole tailings stream without a coagulant or flocculant. The tailings segregate, but form a beach with enriched fines. This technology has been prototyped at commercial scale at Syncrude and provides a method for modest increase in fines capture (CTMC, 2012a, 2012b).

Enhanced Beach Capture

Most (50 to 75%) of the fines produced by oil sands mining are captured in the tailings sand beaches and dykes. There are currently large studies under way to look at approaches to changing discharge methods and pond configurations to further enhance this capture (AMEC, 2013; Fear *et al.*, 2014). Small increases in beach capture can greatly reduce the volume of residual mature fine tailings that need to be treated.

3.3.4 End-Pit Lakes

End-pit lakes are artificial lakes that are created from mined-out pits after they have been partially backfilled with overburden, lean oil sands, and coarse tailings. The remaining void is then converted into an end-pit lake by filling it with either water or fluid tailings capped with a thickness of 5 to 50 m of water (CEMA, 2012). Once acceptable surface water quality is attained, outflow from surrounding terrain is established to emulate a natural lake system (OSTC & COSIA, 2012).

End-pit lakes are expected to provide a natural source of bioremediation, whereby microorganisms break down naphthenic acids (CTMC, 2012a, 2012b). The lakes are also predicted to act as active and passive bioreactors for process-affected water that seeps from the dykes over time so that the water is diluted and, with a long enough residence time, bioremediated to the extent that it can be released to the environment (CEMA, 2012). As many as 35 end-pit lakes (Vandenberg, 2014) are planned for the oil sands region, about half with tailings substrates.

In the Panel's experience, some view these lakes as adding a positive environmental footprint to the region, providing new land uses and allowing passive bioremediation of oil sands process-affected waters, potentially avoiding the need for long-term active water treatment for discharge (CEMA, 2012). Many view these lakes, however, as a high-risk experiment with an uncertain outcome (CEMA, 2012). End-pit lakes are common elsewhere, such as in the metal and coal mining industry, rock quarries, and gravel operations (Castendyk & Eary, 2009; McCullough, 2011). The composition of these lakes varies widely. Some metal mines with acid rock drainage have submerged tailings with poor water quality (CEMA, 2012).

Syncrude started piloting end-pit lakes in the 1990s and is currently running a full-scale prototype at the Mildred Lake site, where in 2012 the West In-Pit tailings facility was converted to a commercial-scale water-capped end-pit lake (Base Mine Lake). Syncrude expects to take 5 to 10 years to fully understand the design and operating parameters of end-pit lakes, and to ultimately prove their viability (CTMC, 2012a, 2012b; OSTC & COSIA, 2012). COSIA is planning a large Demonstration Pit Lakes Project to further advance this technology (Vandenberg, 2014).

There are opportunities to reduce the risks to the oil sands environmental footprint posed by end-pit lakes. Closure plans call for these lakes to be created where there is little risk of breaching; most of the lakes are contained on all sides by bedrock (CEMA, 2012). As indicated by the Oil Sands Tailings Dam Committee (2014), some end-pit lakes will have some containment provided by glacial overburden deposits and wide, robust, engineered earth structures; others are dykes that will be later de-licensed when shown to be safe without ongoing maintenance. The committee also highlighted the need to design extremely robust outlet structures for these lakes. CEMA (2012) indicates that shoreline instability is an important design issue. There are several key geotechnical issues that relate to the potential negative impact of end-pit lakes. In the Panel's view, most can be ameliorated through the use of good design-for-closure practices and close regulatory oversight.

There are few alternatives to the creation of end-pit lakes in the oil sands region (CEMA, 2012). In many cases, the entire reclaimed landscapes are designed to use end-pit lakes as passive bioreactors. The final voids need to be filled with water, tailings, or other mine waste, though the Panel recognizes that many would prefer them to be filled with solid materials rather than fluids.[21]

In addition to the geotechnical concerns listed above, particularly those related to the long-term probability of failure (e.g., Vick, 1990; Aubertin *et al.*, 1997, 2002a), the greatest concerns regarding end-pit lakes generally revolve around uncertainty in future ecological performance, specifically the quality of in-lake and discharge

21 Greater collaboration between operators would allow adjacent mines to use the final pit voids for tailings deposition.

water (Aubertin *et al.*, 1997, 2002a; CEMA, 2012). For instance: will healthy and productive ecosystems form in the lakes? Will they be safe and useful for humans? Will the outflow waters meet discharge quality standards? Will the lakes cause geotechnical instability? The industry remains optimistic, but stakeholder acceptance of end-pit lakes is not assured. As indicated in Section 3.2, the lack of water discharge criteria and the lack of dialogue on the potential for long-term care and maintenance stifle debate on alternatives or enhancements to end-pit lake technology.

3.3.5 Risk of a Tailings Dam Breach

The risk (probability and consequences) of a dam (dyke) breach is highlighted as part of the environmental footprint of the oil sands industry. A dam breach would cause virtually all of the water and a large proportion of the fluid tailings or other potential mobile tailings to suddenly flow out of the breach, away from the dam, presenting hazards to people, infrastructure, and the environment. The Panel notes that the impact of a single major failure on the region and the oil sands surface mining industry as a whole would be very large.

Efforts to reduce this risk have been ongoing for decades. But with the ever-increasing number of operational tailings dams, challenges associated with eventually decommissioning and de-licensing these dams at closure, and the large volumes of water, fluid fine tailings, and other potentially mobile tailings stored behind dykes, reduction of absolute risk in the industry requires a step change in tailings management as described below.

In terms of dam safety and design, the track record of the oil sands industry has been good over the last 50 years, generally applying the best technologies and practices (RSC, 2010). For example, all surface mine operators hire experienced geotechnical engineers; follow the Canadian Dam Association safety guidelines (Canadian Dam Association, 2007, 2014) for design, construction, monitoring, and maintenance; have independent review boards; and have close oversight by experienced regulators. Risk of a breach is usually more significant the longer the operational period for each dam (Aubertin *et al.*, 2002b, 2011); current regulations require that all dams be decommissioned and de-licensed to allow for reclamation certification (Oil Sands Tailings Dam Committee, 2014). However, it seems likely that some tailings dams, especially those not designed for closure from the start, will not be amenable to de-licensing and will require post-closure monitoring and maintenance. There is a need to improve design-for-closure practices for dykes, to work to absolutely minimize the number of dykes and other facilities requiring long-term maintenance, and to start to plan for long-term maintenance of various elements of the closure landscapes in the region (Morgenstern, 2010, 2012). Operational and post-closure seepage from both fine and sandy tailings deposits is also a risk and may require long-term monitoring and management for some structures and closure landscapes.

In the Panel's view, there are a few options to reduce these operational and closure risks. The reduction in the volume of water stored in tailings ponds can be accomplished with changes in management practices and the ability to treat and discharge process-affected water back to the environment (after meeting strict quality criteria). Reduction in the volume of fluid tailings, which has been a central focus of R&D over decades, would allow a greater proportion of tailings to be stored below grade in mined-out pits that can provide geologic containment. Currently, the slow rates of consolidation dewatering of fine tailings mean that their strength remains very low for a very long time, making them untrafficable for reclamation equipment, and increasing mobility in the event of a dyke breach.

Additionally, the use of inclusions made of coarse-grained materials to construct impoundments with different cells, accelerate drainage, add reinforcement, and help with progressive reclamation are being actively explored in other types of mining operations (Aubertin *et al.*, 2002b; James *et al.*, 2013). A similar approach may be applicable to the tailings ponds from the oil sands. If the tailings are made strong enough and a water cap is avoided, the risk of a breach can be significantly reduced (or eliminated in some cases).

As indicated above, good closure planning is essential to creating tailings deposits that do not require containment dykes and to design dykes and tailings ponds that are easier to decommission and de-license and remain low risk at every stage of construction, operation, and closure. As the area of tailings processing matures, a keener focus on these geotechnical aspects of tailings is needed to reduce the environmental footprint. Long-term containment (geological and otherwise) for end-pit lakes, where large volumes of water and fluid tailings will be permanently stored, requires an even higher level of design safety and care. It is also critical that geotechnical problems be addressed in conjunction with environmental issues, and not separately, as is commonly done (Küpper, 2013).

3.3.6 Seepage from Tailings Facilities

Process-affected water from fine- and coarse-grained tailings seeps from all tailings facilities, through the dykes, abutments, and foundations. Controlling this seepage is important to the geotechnical stability of the dam, and to protect groundwater resources and ecosystems in the region. This is, however, a technical and operational challenge.

Management of seepage for operational stability of the dams (dykes) is mature in the oil sands (McRoberts, 2008), as it is in other types of mining operations (e.g., Vick,1990; Aubertin *et al.*, 2002a, 2011; Fell, 2005). Some oil sands tailings dams are constructed of low permeability, lean oil sands, and fines-rich materials; others are constructed of highly permeable tailings sands. Some oil sands dykes have low permeability cores and internal drainage elements (gravel, coke, or slotted pipe drains) to control seepage (McRoberts, 2008). Not all dykes were designed for closure, and the Panel is concerned about their long-term integrity (including that of the internal drains) at closure.

Where process-affected water seeps from tailings ponds and dykes and enters natural aquifers, there can be environmental impacts on soils, vegetation, wetlands, and streams where it discharges to the environment. It also has the potential to sterilize use of the groundwater resource to other users (ESRD, 2012).

Parts of the region are underlain by high permeability sand channels and sand sheets (Stephens *et al.*, 2012; Fenton *et al.*, 2013) that act as unconfined aquifers and make seepage management more challenging. Seepage into natural systems (groundwater, wetlands, and creeks) is managed operationally by the mines. Low permeability liners are used in some tailings deposits. Downstream, deep ditches, low permeability cut-off walls, and active interceptor wells are commonly employed to manage seepage that leaves the facility (Vincent-Lambert *et al.*, 2011). Networks of groundwater wells in the region are used to monitor compliance with groundwater regulations (ESRD, 2012).

Tailings seepage from post-closure landscapes is also an issue. Closure plans show methods for reducing seepage from tailings deposits, mitigating off-site impacts, and accommodating on-site seepage in the reclaimed landscape. Some plans recognize the need for a period of post-closure maintenance to manage seepage from some landforms, for a finite but indefinite period (e.g., Alberta Energy and Utilities Board, 2004). However, a broader view of aquifer risks and management options for oil sands tailings is needed, not only for water quality, but also to highlight the risks and options for water quantity and changing locations of the water table in on-site and off-site aquifers affected by mining (e.g., BGC Engineering Inc., 2013).

Groundwater remains a significant issue in the region (Weber, 2014). The Government of Alberta (2012a) recently released the Lower Athabasca Region Groundwater Management Framework to "manage non-saline groundwater resources across the Lower Athabasca Region including management of potential cumulative effects." Much of the debate revolves around on-site versus off-site impacts, and the quantification of impacts on biota. This debate would be less critical with the systematic and generalized application of efficient methods to control and reduce seepage from the ponds.

There are options for avoidance, source control, groundwater remediation, and groundwater flow system reconstruction (BGC Engineering Inc., 2013). Some of these options are proven technologies, while others are still at the conceptual stage. Some of the greatest improvements for new operations would come from selecting and applying appropriate extraction and tailings disposal technologies and improving the quality of the process water during operation. Most options require a more robust design-for-closure practice for all aspects of tailings management.

In the Panel's view, perhaps one of the greatest impediments to change is lack of an agreed-upon conceptual model for long-term seepage conditions in tailings facilities. There are numerous questions on various aspects such as the hydraulic conductivity of the tailings that remains in external tailings facilities, rates of groundwater recharge and discharge, the levels of salts and naphthenic acids in tailings pore waters, and the potential attenuation of seepage by natural aquifers and aquitards. Closer collaboration of mine operators with the geotechnical, groundwater, and ecological risk assessment communities is needed to improve the state of practice for design, operation, and closure of these facilities.

3.4 APPROACHES TO REDUCE LAND IMPACTS

Oil sands mining includes removing the soil, overburden, and ore over the area of each ore body. Until the pit is sufficiently large to allow backfilling, the reclamation stockpiles, overburden waste dumps, and tailings are deposited onto original ground adjacent to the pit. Provincial regulations require lands disturbed by oil sands operations to be reclaimed progressively to equivalent land use that existed prior to disturbance (Alberta Government, 2014b). While mine reclamation for upland uses is a mature technology, lake, wetland, and riparian reclamation technologies are still under development. Technologies to enhance reclamation for wildlife habitat, traditional land uses by First Nations, and alternate land uses, such as the reclaimed grasslands that now provide habitat for bison at the Beaver Creek Wood Bison Ranch and which is overseen by the Fort McKay First Nation, are limited.

As highlighted in the previous section, no single breakthrough technology exists for tailings management. In a similar vein, land reclamation also requires multiple solutions. Ultimately, the greatest reduction in the land footprint associated with surface mining will be achieved by a combination of treating process-affected water for discharge and dewatering tailings to reduce the volume and improve the composition of tailings ponds. Complementary land management strategies can speed and improve reclamation, especially to prevent mine closure from requiring long periods of care and maintenance. In general, these can be grouped into three broad approaches that reduce mine sprawl, increase the rate of reclamation, and increase the quality of reclamation. These approaches are summarized in Table 3.2.

First, in terms of mine sprawl, the aerial extent of some mine operations is nearly 2.5 times larger than the aerial extent of the ore body. Ultimately, this sprawl, defined as the ratio of the area disturbed to the area of the ore body, is largely driven by the volume of tailings and the desire to provide geologic containment for fluid tailings in the mined-out pit. Sprawl is created when the sand tailings are stored out of pit to leave room for fluid tailings in pit. Second, the rate of reclamation is driven, in part, by a commitment to (and requirement for) progressive reclamation. Oil sands operators reclaim land as soon as it becomes available, typically within a year or two of the land no longer being required for ongoing operations. Third, and handmaiden to speed of reclamation, is quality of reclamation. Continuous improvement is needed, along with practical and reliable techniques for new reclamation challenges, such as the recent fen reclamation (Pollard *et al.*, 2012), and better alignment between industry, stakeholders, First Nations, and regulators. The scale of reclamation on an individual site and as a region has few analogues elsewhere in the world (An *et al.*, 2013).

Table 3.2

Summary of Land Management Approaches

Approach	Strategy
Reducing Mine Sprawl	• Adopting tailings technologies that allow earlier tailings deposition into active mining pits, or adopting extraction technologies that produce dry solids. • Adopting tailings technologies that reduce the total volume of all tailings. • Minimizing use of technologies that create large shallow deposits limited by rate of rise. • Minimizing water storage on site by managing inventories and discharge of treated water. • Minimizing volumes of low-density tailings through more robust technologies and closer monitoring and management. • Sharing tailings ponds and specialized activities like water treatment, tailings treatment, and reclamation between operations and operators. • Improving mine and tailings planning technologies, taking a more conservative approach to adoption of new tailings technologies, and better integrating mine planning, tailings planning, and reclamation and closure planning.

continued on next page

Approach	Strategy
Increasing the Rate of Reclamation	• Adopting tailings technologies that result in landforms that can be reclaimed sooner or adopting alternative extraction technologies. • Avoiding creation of large volumes of fluid fine tailings and choosing technologies that are quickly trafficable to mine equipment or are dense and strong enough to be hydraulically capped with tailings sand. • Sequencing the construction of landforms to enhance progressive reclamation; building to final height as quickly as is practical at one end of the deposit rather than slowly raising the deposit over the entire footprint. • Developing construction and reclamation techniques more amenable to reclaiming the toes of slopes with less risk of erosion. • More closely integrating the mine and tailings planning process with reclamation and closure planning. • Taking a more expedient and less risk-averse approach to tailings ponds closure (e.g., closing and reclaiming tailings ponds that are near capacity). • Incorporating collaborative and state-of-the-art monitoring (regional and site-specific) into both current and future mine, tailings, and reclamation plans. • Establishing formal and active monitoring systems with sufficient data management and quality assurance/control.
Increasing the Quality of Reclamation	• Improving soil stockpiling technologies to help preserve the viability of seeds, propagules, and microbial communities until the reclamation material can be spread. • Improving reclamation material balance planning technologies to help balance reclamation material quantities over the whole mine site to allow for changes to salvage and placement requirements over time. • Developing a landform design guide that complements existing design guides in the region developed by CEMA. • Using coarse woody debris, rock piles, and various other technologies for enhanced microsite development. • Developing guidelines for design and creation of wildlife habitat at various special and temporal scales as part of closure planning, reclamation planning, and reclamation operations. • Adopting and testing geomorphic principles and geographic information systems modelling in landscape design to enhance the geotechnical stability and landscape sustainability. • Enhancing consultation with stakeholders such that operational reclamation plans for each piece of land reflect the state of expectations when the plans are developed.

Devenny (2006); BGC Engineering Inc. (2010a); Eaton & Fisher (2011); CTMC (2012a, 2012b); An *et al.* (2013); Doran (2013); Neufeld (2014)

In general, oil sands reclamation offers a major opportunity to create land uses and infrastructure, even if they differ from the pre-disturbance conditions and land uses (BGC Engineering Inc., 2010a; Doran, 2013; Neufeld, 2014). Land management strategies can expedite reclamation by helping to reduce the mine sprawl and increase the rate and quality of reclamation. Management efforts are especially critical to ensure that mine closure does not require perpetual care and maintenance (Morgenstern, 2010, 2012; Küpper, 2013;

Frank *et al.*, 2014). However, ultimately, the greatest reduction in the land footprint will be achieved by a combination of treating process-affected water for discharge and dewatering tailings to reduce the volume and improve the composition of tailings ponds.

Current development efforts will provide an improved definition of performance factors for the technologies described above. As CTMC (2012a) argues, an adaptive management approach to the deployment and balancing of use of technologies will deliver required outcomes while retaining resource value. Geotechnical engineering and reclamation science together with appropriate measurement protocols are essential elements in adaptive management of uncertainties inherent to this large-scale resource development. Results delivery depends on outcome-directed and performance-based management. To achieve desired outcomes, decision-makers and stakeholders should take into account experience, new information, and evolving social values. Performance monitoring and reporting provide information on environmental conditions and identify the need for ongoing adjustments and change.

3.5 CONCLUSIONS

In the Panel's view, tailings represent the most significant environmental impact of surface mining. There would appear to be no single breakthrough technology that could be adopted over the next 15 years or less to significantly address these impacts. Nonetheless, operators are piloting and adopting a wide range of technologies to reduce the volume of and improve the consolidation of tailings. As such, this combination of technologies, new and old — if used together and tailored for particular geological and geotechnical conditions and tailings streams — may constitute a "silver suite" of tailings management solutions that could provide the path to reduced sprawls, reduced risk, and expedient reclamation. Although industry is planning for and piloting end-pit lakes, this technology has yet to be proven. There are also risks associated with seepage and dyke breach during operation. And while regulators call for walk-away solutions, the long-term risks posed by tailings and water are likely to require perpetual care and maintenance for some parts of most sites (Morgenstern, 2012). Ongoing development of new technology and improved monitoring and management techniques are required to reduce this footprint.

Solvent-based extraction technologies are a promising class of technology to reduce water use and eliminate the production of fluid fine tailings. They are still in an early stage of development, with little to no information available on performance in large-scale operations, costs, or environmental impacts from solvent release. Development of techniques to remove the residual solvents to very low levels would be required to advance this technology.

Preliminary evidence suggests water treatment technologies, if scaled up, have the potential to treat process-affected water for discharge. The Panel notes that treatment and eventual discharge of process-affected water are critical to reduce the volume and improve composition of tailings ponds. As it stands, oil sands operators store process-affected water in tailings ponds, effectively increasing the ponds' size and slowing the pace of reclamation. The proposed COSIA Water Technology Development Centre provides a promising model for joint industry and academia technology development, as discussed in Section 7.3.

Separating the more toxic froth treatment tailings from the other more voluminous tailings streams and effectively treating this stream for return to the mine or to recover bitumen and metals would address two important tailings problems. It would reduce the potential impacts of solvents on groundwater, soils, and surface water over and around these deposits and reduce fugitive emissions resulting from decomposing solvent that remains in froth tailings after treatment.

4

In Situ Production Technologies

- Incremental Process Improvements
- Solvent-Assisted Technologies
- Solvent-Based Processes
- Alternative Thermal Technologies
- Conclusions

4 In Situ Production Technologies

Key Findings

R&D efforts that reduce the environmental footprint of in situ operations have focused on decreasing the amount of natural gas and fresh water needed to generate steam, which is injected into the reservoirs to mobilize the bitumen. Comparatively little R&D is allocated to reducing the land footprint.

Producers are already introducing process improvements, including well flow control devices, and several are experimenting with solvent-assisted technologies. These may be able to increase production efficiency by 15 to 35%.

Several operators are experimenting with solvent-based technologies but, with one exception, these have not yet been commercialized. The potential to deliver better quality bitumen is an environmental advantage. Solvent losses, however, could become a source of groundwater contamination and an economic constraint on the process.

A high degree of uncertainty remains about key aspects of the environmental and economic performance of alternative thermal (electricity-based) recovery processes.

In the near to midterm, no breakthrough technologies to reduce GHG emissions are expected; improvements in environmental performance are therefore likely to be incremental rather than transformative.

SAGD and CSS have proven to be reliable and economic in situ production technologies but they come with significant disadvantages: they suffer high thermal losses, necessitating a high energy input; they must process a lot of water (most of which is recycled) in generating steam and recovering the oil-water emulsion from the reservoir; and, because they rely on steam injected at high pressure, they can only be used safely where a sufficiently strong cap rock (i.e., overburden) contains the pressure. This limits their use at shallow depths.

Oil sands producers have been conducting field-scale experiments with SAGD and CSS technology, often through a process of trial and error, to improve energy recovery and environmental performance. This experimentation is driven by the need to customize the basic technology to the heterogeneous conditions of individual reservoirs and the desire to cut input costs. While field experiments have yielded a large number of new customized or hybrid technologies, many are no more than "incremental add-ons on existing technology ideas proposed in the patent and other literature years to decades ago" (Gates & Wang, 2011). The basic technology on which the many SAGD variants are being tried remains horizontal drilling and, in most cases, thermal stimulation of the bitumen.

As explained in Chapter 2, the environmental concerns raised by in situ production are different from those of surface mining: in situ production is more energy intensive and leads to greater land fragmentation (Jordaan, 2012) as well as surface heave. But it uses less fresh water to produce a barrel of bitumen, creates no tailings, and has a smaller direct footprint than surface mines. As a result, R&D efforts to reduce the environmental footprint of in situ operations have centred on reducing the amounts of natural gas (whose burning releases CO_2 into the atmosphere) and fresh water needed to generate steam to mobilize the bitumen in place. Operators are reducing gas consumption through new technologies such as solvents, alternative heating methods, and new in-well flow control devices (FCDs). Operators that belong to COSIA have set a target of 50% reductions in their freshwater intensity by 2022 through measures such as improving water treatment processes and steam generation efficiency and reducing boiler blowdown waste (COSIA, 2014d).

Courtesy of Gord McKenna

Figure 4.1
SAGD Steam Boilers at Cenovus's Christina Lake Project

The nature of in situ development — shallow wells on dispersed pads exploiting a vast geographical area — also exerts impacts on the land, mostly through the fragmentation of wildlife habitat. Industry has introduced technologies to reduce these impacts (e.g., helicopter-borne drilling rigs) but most of the measures needed to avoid or mitigate these impacts are not primarily technological in nature. They include better design (e.g., cutlines to reduce wolf predation), more widespread adoption of existing good practices including for land reclamation, and more extensive monitoring. The Panel acknowledges the importance of these measures but does not address them in detail.

In addition, operators are evaluating technologies whose prospects and eventual environmental benefits are difficult to characterize because they are still at an early stage of development (e.g., Exxon and Imperial Oil's Slurrified Heavy Oil Reservoir Extraction process for thin and geologically complex oil sands deposits for which SAGD production is uneconomic; biological processes to convert bitumen to methane).

In this chapter, the Panel focuses on technologies to reduce GHG emissions and water use and reviews them together. These technologies fall into four categories: (i) process improvements that boost production and lower costs, (ii) solvent-assisted technologies that involve adding chemicals to steam, (iii) solvent-based technologies that replace steam with chemical solvents, and (iv) alternative thermal technologies that heat bitumen without using steam. These categories are not mutually exclusive, with some firms exploring hybrid thermal-chemical processes that combine elements from more than one category. The Panel reviews technologies combining in situ production with partial upgrading, environmental mitigation (e.g., CCS), and alternate energy sources (e.g., less carbon intensive electricity sources) in Chapters 5 and 6.

4.1 INCREMENTAL PROCESS IMPROVEMENTS

Operators are continually trying to improve their production performance by applying technologies or practices such as improved geological characterization (for better well placement), better well orientation, 4D seismic imagery (to show steam penetration in the reservoir over time), drilling in-fill production wells ("wedge" wells), and deploying in-well FCDs. While each technology or practice may only yield incremental improvements in the steam-to-oil ratio (SOR), collectively these improvements translate into greater production for fewer inputs that reduce the environmental footprint of in situ production.

In a similar vein, all in situ operations have opportunities to improve their energy efficiency through continued equipment optimization, implementation of appropriate management procedures, and adoption of new technologies, all of which reduce associated environmental impacts. Suncor Energy Inc. and Jacobs Consultancy Canada Inc. (2012) identify a long list of operational and capital measures to improve energy efficiency, which together could lead to efficiency improvements of about 8% and reductions in GHG emissions of 12%.

The extent to which individual operators could realize such gains, however, varies depending on individual circumstances. This section describes four examples of energy efficiency technologies applied to in situ production.

4.1.1 Vacuum Insulated Tubing

The use of vacuum insulated tubing in SAGD well bores reduces heat loss and the amount of steam required to produce a given amount of bitumen. Tests suggest that wells equipped with vacuum insulated tubing require fewer (e.g., 75 rather than 90 to 120) days of "pre-heating," before they can start producing bitumen (COSIA, 2014a). A shorter steaming period reduces the fuel and water required, and hence GHG emissions.

4.1.2 Waste Heat Recovery

In 2014, Devon was evaluating the installation of a low-grade waste heat recovery unit at its Jackfish 1 SAGD in situ operation to generate 8 to 10% of the facility's electricity. This unit is expected to result in potential GHG emissions savings of 4,000 tonnes per year (COSIA, 2014e).

4.1.3 Blowdown Boiler Technology

This technology allows an operator to reuse a greater percentage of water to generate steam at its oil sands operations (over 90% of the original input water) by re-boiling process water without treatment. Cenovus commercialized its blowdown boiler technology at Foster Creek in 2011 (Cenovus Energy Inc., 2014b); Imperial Oil and BP are conducting similar research, with results expected in 2015 (COSIA, 2014d).

4.1.4 In-Well Flow Control Devices

In many operations, steam conformance along SAGD well pairs ranges between 50 and 100% of the well pair, reducing production efficiency. In recent years, operators have tested in-well FCDs with promising results. In an FCD-deployed well completion, only a fraction of the well is open for fluid inflow or outflow. Performance at the ConocoPhillips Surmont lease demonstrates that the FCD-deployed SAGD well pair achieves similar steam conformance to a standard well pair. The advantage is that an FCD well requires a smaller wellbore and can be drilled farther than current wells, thereby contacting more bitumen and making the well pair more efficient (Stalder, 2012).

At present, FCDs are at an early stage of development. In the Panel's judgment, early results suggest that they could reduce the SOR by about 10 to 20%.

4.1.5 Chemical Additive Technologies

As part of incremental process improvements, operators have added various materials to steam to enhance the production rate and recovery factor of in situ steam-based processes. The Panel is aware of the following:

Surfactants: These agents reduce the interfacial tension leading to reduction of the amount of trapped oil in the reservoir after steam has passed through the reservoir sand. A few field trials have shown encouraging results.

Thin film spreading agents: These materials act at the interfaces between oil and water and steam condensate. A few field trials using thin film spreading agents have had technical positive results (reduced SORs) but economic feasibility is not yet clear.

Alkaline additives: When an alkali interacts with the acids in bitumen, it generates in situ surfactants. Although the co-injection of alkaline with steam was tested at the Suncor Firebag operation with positive results, testing needs to happen over a longer time period to prove its commercial viability.

Nanoparticles: There have been several attempts to use nanocatalysts and other nanoparticles to accomplish in situ upgrading (Pereira Almao, 2012). Although in its infancy, the process has shown promise in laboratory experiments, but has not yet been tested at field scale in steam-based recovery technologies.

Water film additives: Solvents and additives are added directly to the water to be steamed, which is then used to precondition the reservoir fluids so that when steam is injected, the oil is more mobile. As a consequence, the SOR is improved (Larter *et al.*, 2012a).

At this point, chemical additive technologies are showing promise in laboratory and a few field trials but their performance in reducing GHG intensity and water consumption is not yet established, nor is their impact on groundwater understood.

4.2 SOLVENT-ASSISTED TECHNOLOGIES

In recent years, in situ operators have been experimenting — not always successfully (Souraki *et al.*, 2013) — with adding different quantities and varieties of solvents to the steam that they inject in the bitumen. The addition of solvents (mostly various light hydrocarbons, such as gas condensates or butane[22]) reduces

22 Solvent selection depends on the vapour pressure to be used and the chemical characteristics of the bitumen in place.

the temperature and pressure of the steam required to mobilize bitumen in situ, and hence the energy and water input needed for production. This decreases GHG emissions associated with production. Solvents, however, have two important limitations. Used by themselves, they reduce bitumen viscosity more slowly than steam (Souraki *et al.*, 2013). Solvents are also expensive (as processed products, they cost more than the raw bitumen in the ground); thus the economics of solvent-assisted production depend crucially on the recovery and reuse of the bulk of the solvents being injected (according to the Panel, about 85% recovery is required to make these technologies economic).

It is important to note that the use of solvents reduces the SOR needed to produce in situ bitumen but not necessarily the energy intensity of the process. The intensity depends in part on how much solvent is recovered with the bitumen — the more that is recovered, the lower the intensity.

The optimal solvent type, its concentration, and the length of the injection cycle will vary by reservoir and operating conditions (Li *et al.*, 2011; Souraki *et al.*, 2013). This explains the large number of variants that exist on this theme (see Table 4.1). While solvent-assisted production methods may have different names, they essentially represent a common technology group whose main differences lie in the nature of the fluids injected and the by-products recovered (Li *et al.*, 2011).

Table 4.1

Examples of Selected Solvent-Assisted Technologies

Process Name	Operator	Comments
LASER	Imperial Oil	In commercial application at Cold Lake
Solvent-Aided SAGD	Imperial Oil	Being pilot tested at Cold Lake
Solvent-Aided Process	Cenovus	First commercial-scale field trial of solvent-aided process using butane
Solvent-Cyclic SAGD	Laricina Energy	Will be first commercial bitumen production from carbonate rock
Expanding Solvent SAGD	CNOOC-Nexen	Testing the feasibility of co-injecting gas condensate and steam
SAGD+	Connacher	Testing the feasibility of co-injecting gas condensate and steam
SAGD "Lite"	Suncor	Application of water-based solvents mixed with surfactants to increase oil recovery while using less energy

4.2.1 LASER

A pilot for Imperial Oil's liquid addition to steam to enhance recovery (LASER) technology has shown a 35% increase in production and a recovery of 70% of the solvent used (Dickson *et al.*, 2013). By reducing the amount of steam required, LASER reduces GHG emissions by 25% relative to conventional CSS (Stark, 2013). It is currently using LASER in 240 wells at Cold Lake, which makes it the world's largest application of a thermal solvent extraction process (Stark, 2013).

4.2.2 Solvent-Aided SAGD

Since 2012, Imperial Oil has been field testing its solvent-aided SAGD process where the solvent content is as high as 20% of the injected fluid. This process has a relatively high solvent content compared with other solvent-assisted SAGD processes such as expanded solvent SAGD and solvent-aided process. The results so far demonstrate an improvement in both the oil recovery rate and SOR (Dittaro *et al.*, 2013).

4.2.3 Solvent-Aided Process

Cenovus and its partner ConocoPhillips are currently testing this process in one well at the Christina Lake facility with a view to commercializing it at the Narrows Lake project in 2017, which is expected to have a total gross production capacity of 130,000 barrels per day. The test is recovering 70 to 85% of the butane injected and achieving a lower SOR (Dickson *et al.*, 2013). Cenovus estimates that it will have taken a decade of research, including three years of field tests, to demonstrate this technology.

4.2.4 Solvent-Cyclic SAGD

Laricina Energy has been producing bitumen from the Grosmont Formation since 2011 at its Saleski pilot. A project example (Saleski Phase 1), which will use a combination of cyclic SAGD and solvent-cyclic SAGD, will be the first commercial bitumen production from carbonate rock (Yang *et al.*, 2014).

4.2.5 Expanding Solvent SAGD

At its integrated SAGD and upgrader facility at Long Lake, CNOOC (Nexen) is testing the feasibility of co-injecting gas condensate and steam to improve oil production efficiency. Field-scale simulations suggest that expanded solvent SAGD can improve oil recovery rates by as much as 50% while reducing steam requirements by up to 40% (Nexen, 2014). This plant has higher GHG emissions than the SAGD norm (Elliott, 2008) because the fuel it uses (synthesis gas produced on site) is more carbon-rich than natural gas.

4.2.6 SAGD+

Since 2012, Connacher has been field testing diluent addition to steam (SAGD+) at its Algar operation with positive results. Connacher achieved average bitumen production rates about 30% higher over the first four months of 2013 than the four months prior to the beginning of the test in May 2012. Over this period, steam injection rates dropped by about 10% and, with increased oil rates, the SOR improved by about 33%. Connacher's data suggest that up to 92% of the injected solvent was recovered from the reservoir. Connacher is evaluating SAGD+ as a commercial technology (Connacher Oil and Gas Limited, 2014).

4.3 SOLVENT-BASED PROCESSES

In the solvent-*assisted* processes described in the previous section, steam remains the primary mobilizing mechanism for the bitumen, with various solvents used to enhance the process. In contrast, solvent-*based* processes, such as VAPEX and its variants (e.g., Naphtha Assisted Gravity Drainage and N-Solv) and cyclic solvent processes, use a hydrocarbon such as propane or butane or a mixture of solvents as the primary mobilizing agent. Because these processes do not require steam, they offer the theoretical advantages of much lower energy intensity, no water use, much reduced GHG emissions, and partial in situ upgrading (as heavier bitumen fractions remain in the reservoir). Industry is currently trying both cold and hot processes.

4.3.1 Cold Solvent-Based Processes

Though cold solvent-based processes continue to be tested, they have the disadvantage of slower diffusion through the bitumen reservoir than with thermal conduction (thereby requiring more wells than SAGD for a given production level) (Speight, 2013). This makes these processes economically unattractive and has led industry to largely abandon them.

The exception has been Imperial Oil, which over the past 20 years has been testing cyclic solvent processes for production from its Cold Lake oil sands reservoirs. In this process, a mixture of solvents is injected into the reservoir and allowed to soak the native bitumen for a period of time. The well is then put into production and the solvent-bitumen mixture is brought to the surface. By eliminating the use of steam, Imperial Oil expects the process to improve energy efficiency significantly and reduce CO_2 emission intensity by about 90% (Imperial Oil, n.d.).

4.3.2 Heated Solvent-Based Processes

Industry is experimenting with heated solvents. The N-Solv process, for example, injects a pure, heated solvent vapour into a bitumen reservoir to dissolve the bitumen, with the resulting liquids flowing by gravity to a production well. Operating temperatures are 10 to 50°C higher than the reservoir temperature, and pressures are 50 to 1,000 kPa higher than the original reservoir pressure (N-Solv Corporation, 2014b).

As the bitumen is dissolved into the appropriate solvent, natural deasphalting of the bitumen occurs so that the valuable components of the bitumen are preferentially extracted, leaving the asphaltenes in the reservoir. This allows the N-Solv process to produce a partially upgraded 13 to 16° API oil, while typical bitumen has an API of about 8 to 10° (N-Solv Corporation, 2014b). The main disadvantage of the N-Solv process is the high retention of solvent in the reservoir, which adds to the costs of production (Ardali *et al.*, 2012).

The BEST (Bitumen Extraction Solvent Technology) Pilot Plant, commissioned in 2013, aims to demonstrate N-Solv technology in the field. Suncor's Dover lease is the host site for the 500-barrel-per-day facility, comprising a 300-m horizontal well pair and a surface plant for processing produced hydrocarbons (N-Solv Corporation, 2014a).

The potential environmental advantages of heated solvent-based technologies include a reduction in GHG emissions by some 80% (because less energy is used in both production and subsequent upgrading) and the reduction in net water consumption to zero. In addition, these technologies may deliver better quality bitumen. Solvent losses, however, could become a source of environmental contamination as light hydrocarbons are most commonly used (RSC, 2010). At Cold Lake, 30 to 50% of the solvents injected were not recovered (Stark, 2013). Although they are injected below freshwater aquifers, little is known about possible communication among underground water layers. The potential for high-pressure steam injection or subsequent pressure drawdown through production may increase aquifer connectivity (RSC, 2010). Table 4.2 summarizes the estimated performance improvements of various technologies using solvents.

Table 4.2
Comparison of Solvent Recovery Technologies

Potential vs. Steam Processes	Solvent-Assisted	Solvent-Based	VAPEX
Energy Use, GJ/m^3	-10 to -30%	-40 to -80%	~ -90%
Water Use, m^3/m^3	-10 to -25%	~ -90%	~ -100%
Recovery Rate	+ 20 to + 40%	-50 to + 25%	~ -80%
Increased Recovery	Yes	Yes	No

Isaacs (2012b)

4.4 ALTERNATIVE THERMAL TECHNOLOGIES

The industry is investigating two main alternate thermal technologies for in situ oil sands production: in situ combustion and electricity-based reservoir heating. These technologies are not expected to displace SAGD but they may have niche applications where SAGD is not possible, such as in thin, shaley, and water-rich oil sands deposits.

4.4.1 In Situ Combustion Process

Steam injection does not change the chemical properties of bitumen. In situ combustion (and solvent-based processes) may, however, and therefore the oil it produces is different from the bitumen that SAGD lifts to the surface. By burning the heavier fractions of the bitumen in the reservoir, in situ combustion yields a partially upgraded crude (Speight, 2013). The oil industry has applied in situ combustion to heavy oil recovery with varying degrees of success since the 1970s but this process has proved difficult to control (Greaves *et al.*, 2012). The Canadian operator most closely associated with this technology, Petrobank Energy,[23] has reported a number of technical problems with its toe-to-heel air injection process (THAI) at its field pilot site and has reverted to more conventional production technology (Touchstone Exploration Inc., 2014).

In situ combustion offers the theoretical advantage of a higher recovery of the resource (from 70 to 80%) (CAPP, 2014c). This technology has not yet been proven at a commercial scale and its potential is difficult to characterize.

23 Now Touchstone Exploration Inc.

4.4.2 Electricity-Based Heating

Several approaches to stimulating bitumen electrically exist conceptually, including low- (McGee *et al.*, 2009), medium-, and high-frequency heating (Ghannadi *et al.*, 2014). All of them rely on horizontal wells to heat and produce the bitumen in place and require the injection of a fluid to push the mobilized oil to the surface. Electro-thermal recovery appears to offer a number of advantages, including higher thermal efficiency (from operating at lower temperatures than SAGD), lower pressure, and avoidance of issues associated with SAGD production, such as controlling the movement of injected fluids (RSC, 2010; Zhu & Zeng, 2012). Electromagnetic heating may increase oil recovery and lower GHG emissions by 15 to 40%, depending on the carbon intensity of electricity generation. It may also require a smaller footprint: using gas rather than steam to displace the mobilized oil avoids the costs and space requirements of a water treatment plant (Wacker *et al.*, 2011). However, this technology also raises concerns about induced thermal pressure in shallow reservoirs that could affect cap rock integrity and lead to the uncontrolled release of steam or oil at the surface (Ghannadi *et al.*, 2014).

This technology remains unproven in the field despite significant R&D investment for nearly three decades (Mutyala *et al.*, 2010). This section briefly describes three examples of the technology.

Electromagnetic SAGD

Proposed by Siemens, electromagnetic SAGD would use inductive heating to complement steam injection in the reservoir. Cables would be inserted into well bores parallel to the main SAGD injector and producer. This supplementary heating would allow a broader steam chamber with more rapid bitumen production. Simulations suggest that this technology would be suitable for thin pay zones and shallow deposits. The main questions are the cost of the additional drilling, electrical equipment, and electrical consumption, relative to the incremental oil production and reduced steam addition (Gray, 2015).

Enhanced Solvent Extraction Incorporating Electromagnetic Heating

A variant on the above is to add solvents to electrical heating. A $33-million pilot project (industrial partners include CNOOC-Nexen, Suncor, Devon, and Harris Corporation, and support from CCEMC, the Climate Change and Emissions Management Corporation) is testing a technology called Enhanced Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH). Instead of steam, ESEIEH uses a combination of electricity and solvent to reduce the density of the bitumen so that it will flow. An antenna distributes electrical power in the form of an electromagnetic field that heats the bitumen. A solvent is then injected in a recipe that creates the best balance between heating and dilution.

The ESEIEH field test is being conducted in two phases. In 2012, this project successfully completed an initial proof-of-concept test. Phase 2 moves to an underground deposit and consists of an in situ field pilot test using a 200-m horizontal well (CAPP, 2014f).

Electro-Thermal Dynamic Stripping

Research into electro-thermal processes to mobilize bitumen is more than 30 years old. For the last 20 years, however, this technology has been used primarily to remove VOCs and non-volatile organic matter from contaminated soils (McGee *et al.*, 2009). Electro-thermal dynamic stripping uses electrodes inserted into the ore in situ to heat the bitumen. With support from CCEMC, E-T Energy Ltd. is operating a pilot test site on its Poplar Creek property to determine the feasibility of the technology. A proof-of-concept demonstration in 2006–2007 produced 2,000 barrels of oil with only traces of sand and no emulsions (McGee *et al.*, 2009).

In 2012, the AER declined to grant E-T Energy Ltd. a production licence, judging that the production technology had not yet been demonstrated and encouraged the firm to re-apply at a future date. It is unclear whether this technology will move forward (CCEMC, 2012).

4.4.3 Alternative Thermal Recovery

A combination of three technologies — natural gas decarbonization, oxy-fuel combustion, and the injection of CO_2 to enhance oil recovery — has been proposed for highly saturated reservoirs to radically reduce GHG emissions and water consumption from in situ production (Nduagu & Gates, 2014). This concept, which has not yet been field tested, involves the following steps:

1. Burning the natural gas in an oxygen-rich environment to fuel the process to generate a concentrated stream of CO_2 and provide the temperatures required for step 2;
2. Decomposing natural gas at a high temperature to generate hydrogen and carbon black;
3. Using the produced hydrogen in combination with oxygen in a direct contact boiler (more efficient than typical industrial boilers) to generate steam;
4. Injecting the produced steam and CO_2 into the reservoir to enhance bitumen recovery and sequester the CO_2; and
5. Using the water produced in the hydrogen combustion process to reduce freshwater requirements.

Because this process would require less energy input and produce less CO_2 in mobilizing bitumen from suitable reservoirs, in the Panel's estimation, it could theoretically result in lower GHG emissions than conventional oil production.

4.5 CONCLUSIONS

More field experience is required to reach reliable conclusions about the long-term environmental performance of in situ extraction technologies. For the foreseeable future, environmental performance improvements are likely to be incremental rather than revolutionary, with no breakthrough technology to reduce GHG emissions on the horizon (Gates & Wang, 2011; Ardali *et al.*, 2012). The water recycling performance targets to which COSIA members have committed imply as much (COSIA, 2014c).

In situ operators are making incremental improvements to their production efficiencies in SAGD and with solvent-assisted processes. These improvements are steadily reducing GHG emissions on a per barrel basis. While operators do not always reveal the full impacts of the technologies they use or test, these solvent-assisted technologies appear to reduce SORs by 15 to 35%. A reduction of 25 to 35% in GHG emissions would bring in situ bitumen production closer to current emissions from mining operations and to conventional crude oil[24] (Charpentier *et al.*, 2011; Lattanzio, 2014). There are limits to these improvements, however, because future production will increasingly come from lower-quality deposits (i.e., thinner, less permeable, more geologically heterogeneous) that are likely to require more, rather than fewer, inputs to produce.

Several operators are experimenting with solvent-based technologies but, with the exception of Imperial Oil's LASER process, these have not been commercialized yet. Along with the remaining technological challenges (e.g., solvent recovery ratios), the relative costs of diluents, natural gas, and produced bitumen will determine commercialization.

24 Life cycle comparisons of the GHG impact of different crude oils depend crucially on the methodologies being used, particularly the boundaries applied (e.g., well to tank versus well to wheel).

A high degree of uncertainty remains about key aspects of the environmental and economic performance of electricity-based recovery processes. Challenges include the cost of electricity, its source, and process efficiency (Isaacs, 2012b). These processes could turn out to be GHG intensive (e.g., if they rely on coal-fired power generation) or at least not much better than SAGD. Conversely, there are niche opportunities for electric/electromagnetic in situ processes in reserves where SAGD and CSS are not practical. Combined with a low carbon energy source, these processes offer the potential for significant GHG emissions reduction.

5

Bitumen Upgrading Technologies

- Management of Carbon in Upgrading By-Products
- Substitution of Energy Sources
- Improved Upgrading Technologies
- Reducing the Energy Inputs to Existing Processes
- Conclusions

5 Bitumen Upgrading Technologies

Key Findings

Technologies to capture and sequester carbon emissions from upgraders exist but are not economic at current carbon prices. Practical considerations in retrofitting upgraders for CCS likely limit carbon capture to 20 to 40% of the carbon stream.

Upgrader by-products, such as coke and asphaltenes, are rich in carbon. Sequestering them, through land reclamation in the case of coke or in tailings ponds in the case of asphaltenes, reduces carbon emissions.

Partial upgrading offers several potential advantages, including reducing or eliminating the need for diluent in pipeline transportation.

While research is under way on several new upgrading technologies, most remain at an early stage of development and are not expected to reduce GHG emissions substantially. The possible exception is sodium metal desulphurization, which consumes large amounts of electricity.

The dominant environmental impact of bitumen upgrading is the emission of CO_2 from the fuel consumed for driving high temperature processes, and from the production of hydrogen to remove sulphur from bitumen and improve product quality. Other atmospheric emissions such as SO_2, NO_x, and ammonia met Alberta Ambient Air Quality Objectives in 2012 (Percy, 2013). Like other capital intensive industrial processes, upgraders consume large quantities of water for process and cooling. Much of this water is recycled; all of it is treated using well-established wastewater treatment technologies before being discharged back into the environment (Alberta WaterSMART, 2009).

Unlike surface mines, upgraders do not need to impound large bodies of water. They also produce solid by-products, such as coke and sulphur, many of which are stockpiled on site. Some coke is now being integrated into land reclamation, a practice that helps to sequester carbon that might otherwise be released into the atmosphere if the coke were used as fuel. Sulphur blocks (currently standing at 10 million tonnes) (AER, 2015) can be melted and transported to market, albeit expensively from remote locations. This process is common elsewhere in Alberta. Alberta regulations require the removal of these sulphur blocks before project closure.

The main environmental challenge that oil sands upgraders pose therefore is to reduce their GHG emissions footprint (defined in Box 5.1). Addressing this challenge may involve a combination of:

- sequestering carbon, by using, for example, coke in CCS or land reclamation;
- substituting inputs to use lower carbon sources of energy or hydrogen (e.g., electrification of the hydrogen generation process with a low carbon source such as hydroelectricity[25] and electrolysis);
- improving partial upgrading technology to reduce or eliminate the need for diluent in transportation, to reduce capital cost, to increase the yield of liquid crude oil produced from each cubic metre of bitumen, or all of the above; and
- reducing the energy inputs required for upgrading by making process changes that increase energy efficiency (e.g., using low-temperature catalysis).

Each of these options, which are discussed in this chapter, offers possible reductions in GHG emissions. The first two could decarbonize upgrading (100% reduction is theoretically possible albeit economically out of reach currently) while the latter could, based on the Panel's knowledge, give benefits in the 5 to 10% range at most. However, none offers a technological breakthrough at this time. Setting CCS aside, which the Panel reviews in the next chapter, only two technologies have the potential to reduce GHG emissions significantly at this time (i.e., by 10% or more).

The first technology is partial upgrading, and partial upgrading in combination with in situ production. Partial upgrading leaves asphaltenes in the reservoir, allowing only lighter fractions of the bitumen to be produced (see Chapter 4). This can be seen as a form of carbon sequestration. A range of processes (discussed later in this chapter) have been suggested for partial upgrading on the surface, after the bitumen is produced by in situ or mining extraction.

The second technology is the use of coke in land reclamation. The burial of produced coke sequesters carbon as long as the coke is not subsequently reclaimed as a fuel for combustion. This technology is already being used, notably by Suncor.

25 The Panel examines possible alternative sources of electricity for the oil sands in Chapter 6.

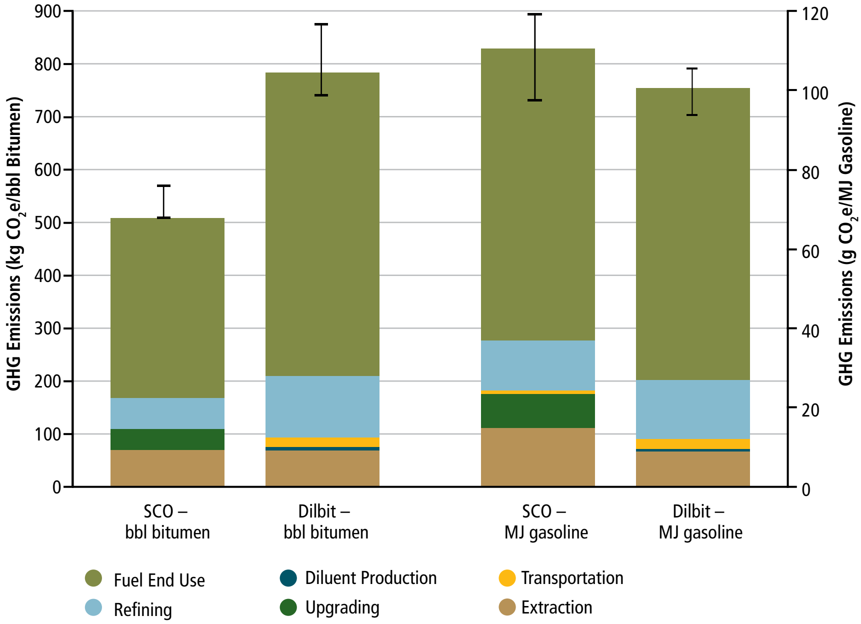
Other technologies are theoretically possible but remain distant: sodium metal upgrading (see Section 5.3.4) offers potential to reduce GHG emissions but this technology is still being tested. Biological in situ upgrading processes that convert bitumen into methane are theoretically possible but have not yet been demonstrated to be feasible. Although possible in the long term, they are therefore unlikely to be viable in the foreseeable future.

Box 5.1
Calculating Life Cycle Emissions of Produced Bitumen

There are three main approaches to calculate the life cycle emissions of produced bitumen (see Charpentier *et al*., 2009):

1. CO_2e per megajoule (MJ) SCO: This approach normalizes the emissions to the output product from the upgrader and captures the different amounts of bitumen required to produce the same amount of SCO. The downside is that the quality of SCO can vary greatly and this difference is not captured.
2. CO_2e per barrel bitumen: This approach normalizes the emissions based on input. The advantage is that one starts with a constant amount of product going into the process; the disadvantage is that the analysis does not differentiate among the final products that are created (which can be very different in amount and quality/utility).
3. CO_2e per litre or MJ of refined product (e.g., gasoline): This approach is often referred to as "well to wheel" because it covers the entire life cycle from the production of raw bitumen to the consumption of refined products. However, because consumption of transportation fuel accounts for between 60 and 80% of CO_2 emissions associated with the use of oil, this approach obscures the differences in carbon intensity among different grades of crude. Per kilometre driven would also help to focus the comparison on the service provided by this product (i.e., transport).

The choice of these approaches can make a substantial difference to the results (see Figure 5.1). The figure considers emissions on a barrel of raw bitumen basis (approach 2), and sets the boundary for analysis as the point at which either the SCO or dilbit enters a pipeline for long distance transport to market (i.e., refinery).



Reproduced from *Energy Policy*, 61(2013), Choquette-Levy, N., MacLean, H. L., & Bergerson, J. A. "Should Alberta upgrade oil sands bitumen? An integrated life cycle framework to evaluate energy systems investment tradeoffs." 78-87, 2013, with permission from Elsevier

Figure 5.1

The Implications of LCA Assumptions

An LCA of GHG emissions from upgraders is not straightforward: the assumptions made about inputs (what is the environmental footprint of natural gas or diluents?), geographical boundaries (e.g., how should U.S. refineries receiving Canadian bitumen be considered?), the disposition of by-products (e.g., is coke burned or sequestered?), and the quality of the SCO produced (e.g., should the focus of the analysis be raw bitumen, SCO, dilbit, gasoline, or km driven?) can lead to quite different results.

5.1 MANAGEMENT OF CARBON IN UPGRADING BY-PRODUCTS

All of the current and proposed upgrading technologies result in by-product streams with low hydrogen content:

- *Coke:* From delayed coking, fluid coking, or proposed new coking technologies (e.g., at CNRL, Suncor, and Syncrude). Operators had accumulated some 87 million tonnes of coke in mid-2014 (AER, 2014c), a number that is increasing by about 6 million tonnes a year.
- *Unconverted vacuum residue after hydroconversion:* For example, at Shell, where 80% of the vacuum residue fraction is converted and remaining unconverted material is blended with lighter fractions and sold as a heavy sour oil blend.

- *Asphaltenes:* Separated either as part of the froth treatment process in mining (Imperial Oil and Shell projects) or by solvent deasphalting (CNOOC Long Lake).

The separation of asphaltenes during froth treatment in the mining operations can be considered as part of the production process. It removes approximately 8% of the bitumen to provide a nearly solids-free bitumen for pipeline transport. The other properties of the bitumen are somewhat improved, such as lower metals content and a reduced tendency to form coke, but 25 to 30% volume of diluent is still required to transport the oil. This case is a partial deasphalting approach, and its product volume-diluent relationship falls on the curve in Figure 5.2.

In practice, there are four possible ways to use these by-product residues:
- gasification and syngas conversion to hydrogen to meet the upgrader's energy requirements, which is the fate of the asphaltenes at CNOOC Long Lake;
- gasification and syngas conversion to synthetic oil for sale;
- use in land reclamation, which is consuming a significant amount of coke at Suncor; and
- combustion with flue-gas scrubbing to capture the sulphur, which consumes a fraction of the coke production at Suncor and Syncrude.

The choice between the first two options is primarily dependent on the natural gas/crude oil price relationship (Wagner & Kresnyak, 2013). Gasification of asphaltenes, vacuum residue, and petroleum coke is capital intensive and currently economically unattractive given abundant natural gas supplies. If these by-product streams are used as fuel, either by direct combustion or gasification without CCS, they will contribute a significant amount of GHG emissions.

The coke from refineries that process diluted bitumen and from the Husky Upgrader (in Saskatchewan) is typically used as fuel in boilers and in metals processing. Bitumen coke has other potential uses, some of which have environmental benefits. In laboratory experiments, for example, petroleum coke has been found to reduce the toxicity of oil sands process water to aquatic life (Zubot *et al.*, 2012).

Coke is currently used as floating cover to cap oil sands soft tailings (RSC, 2010). Coke capping involves using petroleum coke to create a solid surface on top of a fabric laid on a tailings pond. Suncor's Pond 5 coke-capping project is one of the largest field trials of a tailings technology anywhere in the world. An area of 230 ha is currently covered by a 2 to 4.5 m thickness of gravel-sized coke placed over a strong geofabric lain on a frozen tailings surface (Wells *et al.*, 2010;

Abusaid *et al.*, 2011). Tailings sand will ebb when placed over the coke and the entire area covered with reclamation material to create a reclaimed boreal forest watershed. Another potential use for coke in land reclamation includes depositing porous layers to allow drainage of water from tailings. These land applications sequester the carbon in the coke, and would avoid significant future CO_2 emissions. Coke is already used as drainage material in Suncor dykes (McRoberts, 2008).

Given coke has an inherent energy value (similar to that of anthracite coal) (BGC Engineering Inc., 2010), the Panel notes that governments sometimes stipulate that coke used in land reclamation must be recoverable for possible future consumption (e.g., ERCB, 2010), which may limit its use for reclamation. The management of this by-product thus creates a trade-off: is coke more valuable as a possible future energy supply or as an input in current land reclamation? The Panel believes that additional studies on the long-term behaviour of buried coke, notably on the risks to seepage posed by leaching, are needed to answer this question definitively. The literature on vanadium in coke suggests that coke is not inert when stored in reclaimed land and that leaching of vanadium could reach threshold levels, for example, in surface water, when leaching conditions are favourable (Puttawswamy, 2011). This issue has not yet been considered significant enough to preclude in-ground coke storage.

In the Shell and Imperial Oil mining operations, about 8% of the bitumen is removed as solid asphaltenes, which are currently deposited in tailings ponds. Although this material has potential fuel value, it is stable and biologically inert when deposited in the tailings. Consequently, this deposition is another form of sequestration of carbon from the bitumen. Like coke, asphaltenes are a potential energy source with high carbon and sulphur content. Because partial upgrading may result in the removal of asphaltenes from bitumen, this material should also be considered for underground storage or in land reclamation depending on location, rather than as an energy resource.

When coke, asphaltenes, or residual heavy fractions are produced in association with a mining operation, there is an option to sequester the carbon in the mine. When these by-products are generated at an in situ operation, in Edmonton or at refinery sites, such sequestration becomes more expensive as these materials need to be landfilled.

Several proposed upgrading technologies, such as the MEG Energy HI-Q process, would produce asphaltenes as by-products of the upgrading process. The lack of any market for asphaltenes as a fuel has hampered adoption of these technologies. For example, Shell considered removal of asphaltenes as part of the expansion of the Scotford Upgrader (Shell Canada Ltd., 2005). This option was eventually dropped because no market was available in Edmonton, and gasification or shipment back to the mine for sequestration was too expensive.

5.2 SUBSTITUTION OF ENERGY SOURCES

The main energy options for upgraders are natural gas, cracked gases from the upgrading process, coke, heavy fractions of bitumen such as asphaltenes, and vacuum residues. Because of current natural gas prices and air quality regulations, current practice favours the use of gases. All upgraders make effective use of the cracked gases, and all use natural gas. In contrast, coke, asphaltenes, and vacuum residue are all much higher carbon content fuels, and have higher CO_2 emissions unless coupled with CCS.

5.2.1 Gasification of Asphaltenes

The CNOOC (formerly Nexen) Long Lake upgrader is the only example in operation that uses gasification of heavy fractions to produce fuel gas and hydrogen, rather than natural gas. It is fundamentally different from other designs in its integration with a SAGD project. The integration creates a large demand for fuel gas to meet steam demand, which the project provides by gasifying the asphaltenes from the bitumen (Gray, 2015). The asphaltenes are removed from the bitumen and sent to a gasifier to convert them into synthetic gas. The remaining bitumen is cracked to produce lighter distillates. Hydrogen is removed from the syngas and used in the hydrocracker to process the cracked distillates into a low-sulphur product. The remainder of the syngas is used to fuel the site's energy needs.

The use of asphaltenes as a fuel, via gasification, increases CO_2 emissions per barrel in comparison with plants that use natural gas. The North West Redwater Refinery, currently under construction, plans to gasify unconverted vacuum residue and then capture the CO_2 for use in enhancing oil recovery in nearby oil fields (EUB, 2007). Gasification is a well-established commercial technology. Improvements in gasification technology, such as the Western Hydrogen molten salt process, have the potential to reduce the cost of gasification, but this does not, in the Panel's view, change the GHG footprint of this approach relative to existing gasification technologies unless coupled with CCS.

5.2.2 Alternative Hydrogen Production

The large amounts of forest (branches and tree tops) and agricultural (wheat and barley straw) residues that are generated each year in Western Canada could, in theory, be collected to manufacture hydrogen. The use of biohydrogen would greatly reduce GHG emissions from upgrading but would be a source of VOCs, PAHs, and $PM_{2.5}$. The technologies for biomass gasification are well known but remain uneconomic without putting a value on carbon (Sarkar & Kumar, 2010). In any event, this could only be a partial solution as Western Canada does not produce enough agricultural and forest residues to replace natural gas completely in upgrading processes. Coupled with CCS, this is the only technology offering the possibility of negative CO_2 emissions from bitumen upgrading.

Other methods for producing hydrogen, such as electrolysis of water, are technically feasible but are even more expensive (Jaccard, 2005). In addition, the source of the electricity would have to be low carbon to have a significant impact on GHG emissions. Research is also under way to use microbial activity to generate hydrogen directly within petroleum reservoirs but the feasibility of this technology remains untested (Larter *et al.*, 2012b).

5.3 IMPROVED UPGRADING TECHNOLOGIES

The established technologies for producing upgraded liquids from heavy oils and bitumen are based on three main pathways:

- Thermal cracking at low pressure and high temperature is used to produce lighter distillates. Coke is often formed in these processes.
- Hydroconversion cracking at moderate temperatures, in the presence of hydrogen and a catalyst at high pressure, is used to produce lighter liquids and not coke.
- Gasification is used to convert heavy fractions to syngas (carbon monoxide + hydrogen) followed by conversion of the syngas to liquid products.

The first two pathways are used in Canada for bitumen conversion, while the gasification to liquids path is used for coal in South Africa.[26] Most of the new upgrading technologies are variants of the three pathways. Some of these processes give a product of lower quality than the existing upgraders, in terms of liquid density, sulphur content, and metals content, but better than the initial bitumen. This approach is often referred to as partial upgrading. The minimum requirements for pipeline transportation are a density less than 940 kg/m3 (API gravity over 19°) and a viscosity low enough for effective pumping. For bitumen to meet the density requirement, a significant change in the composition of the crude oil is required, either by removing dense components such as asphaltenes, removing sulphur, or increasing the hydrogen content (Gray, 2002). Viscosity is easy to reduce by subtle changes in the crude oil (Wang *et al.*, 2014), but density is much more difficult to alter.

26 Gasification to liquids is not used in Alberta for processing bitumen fractions due to high capital costs.

Industry's interest in partial upgrading at the surface has been driven by three main concerns. First, conventional upgraders require economies of scale and very large capital investments. If new technologies offer simpler processing, these costs may be reduced. Second, producers want small-scale processes that can be used in association with in situ production. Third, where they dilute rather than upgrade bitumen, producers seek to reduce their need for diluent in pipeline transportation because it is expensive and takes up valuable pipeline space.

No partial upgrading technologies at the surface are currently in use in Western Canada because they are not yet economic. Apart from the capital cost, which is hard to predict for a conceptual process, the difficulty is that the removal of components from the bitumen to reduce density and enable pipeline transportation also reduces the volume of marketable crude oil (see Figure 5.2).

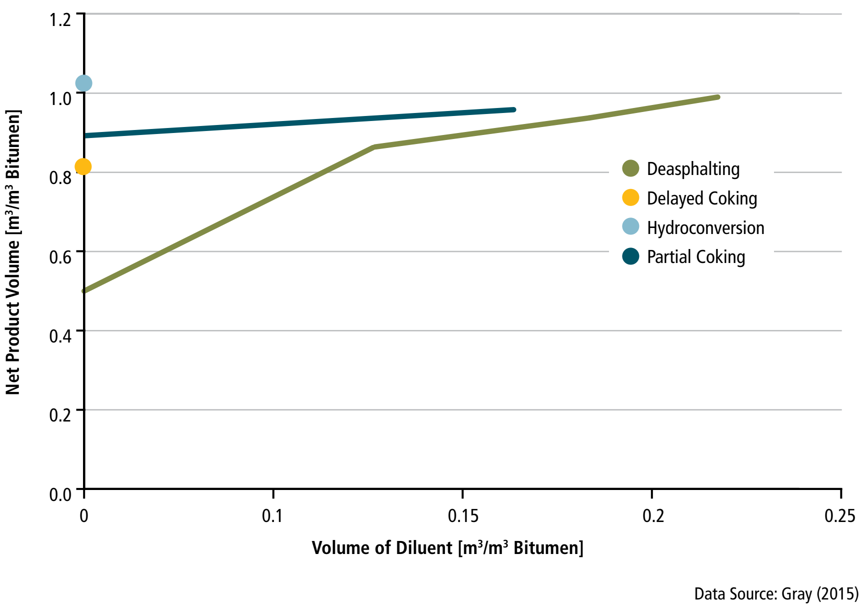


Figure 5.2

Impact of Partial Upgrading on Volume of Marketable Crude

This figure shows the volume of salable liquid product versus amount of diluent required for upgrading processes. Data are for Cold Lake bitumen, based on an asphaltene density of 1,200 kg/m^3 and a coke density of 1,450 kg/m^3. Lines for deasphalting and partial coking are for a product density of 940 kg/m^3 (19° API).

When a producer sells diluted bitumen, all of the components of bitumen are sold. If dense asphaltenes are removed as part of an upgrading scheme, the volume of the remaining bitumen is reduced but it is less dense, requiring less diluent to meet the pipeline requirements. The curve for deasphalting in Figure 5.2 illustrates the range of net product volumes for this approach.

Only one proposed technology is radically different: the use of sodium metal to upgrade bitumen by removing sulphur and metals. Other new technologies such as slurry hydrocracking, novel coking, and other methods of hydrocracking boost the yield of distillate products but they are unlikely to reduce GHG emissions by more than 10% (Gray, 2015). Technologies that remove asphaltenes or coke have the potential to increase GHG emissions per barrel of bitumen, depending on whether the material removed is used as fuel or not. While the precise numbers will vary by technology, the GHG emissions associated with most partial upgrading schemes are likely to fall between those of dilbit and fully upgraded SCO (see Figure 5.1).

5.3.1 Improved Thermal Cracking Technologies

Industry is testing various improved thermal cracking technologies, three of which are described here.

Ivanhoe Heavy to Light Process

Ivanhoe Energy is promoting the Heavy to Light (HTL) upgrading process, a derivative of fluid catalytic cracking technology (Ivanhoe Energy, 2014a). This process converts the heaviest residue to high yields of lighter, lower viscosity, and more valuable products with a minimum production of less desirable by-products, such as coke and gas (Cabrera *et al.*, 2012).

The HTL process has the potential to reduce or eliminate the need for diluent in pipeline transportation. It also converts coke and gas by-products in situ to steam or power, and this energy is available to the operator to develop the field. Ivanhoe Energy claims that HTL facilities can be economically applied in scales as low as 10,000 to 20,000 barrels per day (Ivanhoe Energy, 2014a).

Ivanhoe Energy tested the technology in a 1,000 barrel per day Commercial Demonstration Facility in Bakersfield, California (Cabrera *et al.*, 2012) and began the design and engineering of full-scale HTL facilities for its shallow

SAGD Tamarack project near Fort McMurray. In March 2014, the firm ceased activity on its Alberta project pending the development of a new regulatory framework for shallow SAGD projects by the AER (Ivanhoe Energy, 2014b).[27]

While integrating a field upgrader with an in situ production facility can yield energy efficiency gains, the use of heavy ends as fuel can lead to significant increase in GHG emissions compared with the alternative of using natural gas and upgrading. Consequently, this technology is unlikely to reduce GHG emissions relative to established coking technologies although it offers the advantage of eliminating the need for diluent in transportation.

MEG Energy HI-Q

MEG Energy, in collaboration with AI-EES, has developed an upgrading technology that may obviate the need for diluent for pipeline transportation. The MEG Energy HI-Q process uses integrated thermal cracking and solvent deasphalting technology to upgrade bitumen and produce more of the valuable liquid products and less of the low value by-products normally associated with upgrading. While it would be possible to convert by-products (asphaltene) to pipeline-quality synthetic natural gas, syngas, or hydrogen, or as fuel for steam, the processing of such heavy feeds is not competitive with natural gas at current prices. Such processing would also add to the technology's CO_2 footprint if it was not associated with CCS.

The claimed environmental advantages of this technology include a reduction in energy intensity of over 20% (and therefore lower GHG emissions) and the elimination of the need for diluent in transportation (SDTC, n.d.). In 2013, MEG Energy applied to Alberta regulatory authorities for approval to construct and operate the HI-Q pilot plant. This plant would have a capacity to process 480 m^3 per day of bitumen (3,000 barrels per day) and operate for about three years (AER, 2013d).

ETX Systems IYQ (Increased Yields and Qualities)

This process would replace delayed coking technologies now mostly used in primary upgrading. It offers a novel combination of two commercially proven technologies for the primary upgrading of heavy oil. These technologies optimize the residence time of the fluidized solids and liquid feed, and use lower reactor temperature than competing fluid bed processes to maximize liquid production while minimizing gas and coke by-products.

27 Shallow SAGD projects raise greater environmental risks than deeper projects because the overburden (cap rock) over the bitumen deposits may not resist the high steam pressures being used, thus leading to uncontrolled oil releases.

As well as offering lower capital and operating costs, the process claims that greater liquid yields and lower coke by-product formation would ultimately translate into a 9% reduction in upstream CO_2e. Further reductions in CO_2e emissions and energy savings may be possible downstream due to the higher hydrogen content of upgraded SCO (ETX Systems Inc., 2009).

ETX has received $2 million in support from AI-EES for further development work. In 2013, the operator was planning a 1,000 barrel per day field demonstration project (ETX Systems Inc., 2013).

5.3.2 Improved Hydroconversion Technologies

AI-EES, in partnership with UOP and Statoil, has unveiled a new production technology that takes low-grade bitumen distillation residue and turns it into high-quality products such as SCO and transportation fuels. Based on the Canmet slurry phase hydrocracker, this technology was developed by researchers at Canmet's laboratories and first demonstrated at the Petro-Canada Montréal refinery in the 1980s. It has since been successfully piloted with Alberta bitumen and is expected to provide higher yields of product compared with existing technology, along with significant capital and operating cost advantages (AI-EES, 2012).

Headwaters' HCAT offers a similar approach and is the first technology to use a simple, two-phase (liquid and gas), hydrocracking reactor system. The HCAT Hydrocracking Catalyst is a single molecule catalytic agent that is introduced with the residual feed. By reducing the catalyst to the size of a single molecule, the reaction system can be optimized without having to deal with unwanted side reactions and by-product formation. This enables the refiner to convert more of the residual feed going into the hydrocracker into higher-value distillates. HCAT was successfully demonstrated in a European refinery in 2011 (Headwaters Inc., 2011).

Although slurry phase upgrading technologies are being offered commercially by ENI (Italy), UOP, and Headwaters as full upgrading technologies, there has been no uptake in Canada. These technologies could in principle be used for partial upgrading (low catalyst loading and hydrogen consumption) but are likely to be too capital intensive. The overall environmental benefit of this technology, in the absence of carbon capture, is, in the Panel's view, low.

5.3.3 Improved Gasification to Liquids Technologies

An alternative method for capturing the carbon from gasification of heavy fractions is to use the Fischer-Tropsch process to boost the liquid yield. Gasification of heavy fractions and coke is a well-established commercial technology. New gasification processes are being developed, such as the Western Hydrogen molten salt process, but they do not fundamentally change the GHG footprint of this approach.

Fischer-Tropsch Crude Process

The Fischer-Tropsch crude process is a gas to liquids technology that converts carbon monoxide and hydrogen into hydrocarbon liquids. Invented almost a century ago, it was used initially to convert coal syngas into diesel and gasoline. The process can be applied in a wide variety of facilities such as an existing upgrader that produces asphaltenes, unconverted hydrocracked residue or coke, or in any heavy crude refinery producing asphalt or heavy fuel oil as unconverted residue. Expander Energy, which owns the intellectual property, is in contract negotiations with Kitimat Clean Ltd. for a licensing agreement to incorporate this process into a proposed 400,000 to 500,000 barrel a day refinery near Kitimat, British Columbia that would process Alberta bitumen.

While converting vacuum residue into hydrogen and a dry, pure CO_2 stream has a higher GHG intensity than steam methane reforming, overall both approaches produce similar amounts of CO_2 when the life cycle of all products and by-products is taken into consideration (EUB, 2007).

The Fischer-Tropsch crude concept claims several advantages when employed in a hydrogen-addition upgrader, including high feedstock carbon retention, cost savings at current and forecast ratio of natural gas to crude oil prices, increased operational reliability, and improved flexibility and marketability of products (Wagner & Kresnyak, 2013). The biggest obstacle to deployment appears to be high capital costs.

5.3.4 Other Technologies

Sodium Metal Desulphurization

One radically different approach to upgrading is to react the bitumen with sodium metal (Brons *et al.*, 2001). Mixing sodium and bitumen at about 350°C in the presence of hydrogen gas removes significant amounts of sulphur, nickel, and vanadium. The removal of the sulphur from the bitumen molecules gives a much lower density oil product and significantly reduces its viscosity. The resulting oil is light enough to be transported by pipeline without adding diluent. The removal of metals increases the value to downstream refineries because a wider range of processes can be used to convert the oil into transportation fuels (Brons *et al.*, 2001).

The challenge is to separate the by-product of the process (sodium sulfide) and reprocess it to generate H_2S and sodium metal. This requires electrolytic conversion at high temperatures and consumes large amounts of electricity. Although several firms have received patents on the use of sodium metal, electrolytic regeneration has so far not been successful enough to commercialize the technology.

Sodium metal upgrading offers the potential of dramatically reducing natural gas consumption but it requires large amounts of electricity. Its impact on GHG emissions would therefore depend on the carbon intensity of the electricity to be used. Field Upgrading Ltd. plans to open a pilot project adjacent to the Western Hydrogen pilot. It is expected to be operational by the first quarter of 2015 (Alberta Government, 2014d).

5.3.5 In Situ Upgrading Processes

In the Peace River oil sands, Shell has developed a way to lighten the oil while it is still in the ground through heaters that raise the temperature in the reservoir to over 350°C. Such temperatures crack the oil in situ. The oil is converted into coke, which remains in the formation, and light cracked products, which are collected as vapours from the reservoir (Vinegar *et al.*, 2006). Shell has drilled 29 wells for the field test: 18 wells containing heaters, 3 producing wells, and 8 observation wells. Since starting up the test in 2004, Shell has produced over 100,000 barrels of light oil (Shell Global, 2014).

This process offers several advantages, including process simplicity by not having to inject air or solvents, high recovery ratios (50% on average compared with the typical 20% for the traditional method Shell achieved at its Peace River operation), and yielding pipelineable oil (Shell Global, 2014). However, the energy requirements are significantly higher than SAGD due to higher operating temperatures.

In situ catalytic conversion has been proposed as an adjunct to in situ combustion recovery processes (see Chapter 4). In situ combustion generates off-gases that contain carbon monoxide and hydrogen. Introduction of metal sulphide catalysts has the potential to use these gases to upgrade bitumen. Two approaches have been proposed involving addition of a catalyst: (i) nanoparticles (Hashemi *et al.*, 2014), or (ii) a pack of pellets around the production well (Hart *et al.*, 2014). Given the challenges in commercializing in situ combustion technology, the further addition of in situ upgrading steps to these production techniques is not likely to be commercial in the medium term.

An alternative catalytic approach has been suggested by Ovalles *et al.* (2003) to use lower temperatures and specially treated oil fractions to provide hydrogen by catalytic transfer reactions in the reservoir. As a further modification, they propose the use of methane as a reactant in these processes. Such a technology could be used as a modification of solvent-assisted techniques (Section 4.2), but the specially treated oil fractions and catalyst would increase cost, and the recovery of these components from the reservoir would be lower than in the solvent-assisted SAGD processes that are under development.

In situ biological processing has been proposed as a means of generating methane or hydrogen from petroleum reservoirs (Head *et al.*, 2014), but this approach is unlikely to compete with production of natural gas economically. Biological upgrading of bitumen to produce better quality liquid products has yet to be demonstrated reproducibly.

5.4 REDUCING THE ENERGY INPUTS TO EXISTING PROCESSES

Most of the energy that upgraders use is either generated from the by-product gases from the feedstock, or derived from natural gas. Only CNOOC at Long Lake makes extensive use of solid by-products for energy production, using asphaltenes to produce fuel gas.

Energy efficiency measures provide scope for reducing the energy intensity of the processes, but are unlikely to shift it dramatically. Operators are already implementing measures to increase the efficiency of their energy use (e.g., cogeneration to produce steam and electricity, process optimization, introduction of more effective catalysts), several of which have environmental benefits from reduced waste or energy consumption. About 70% of the energy an upgrader consumes comes from gas combustion (both internally generated fuel gas and purchased natural gas).[28] Measures that reduce this consumption are likely to yield the highest benefits. Suncor Energy Inc. and Jacobs Consultancy Canada Inc. (2012) identify a series of individual measures that could be taken to reduce the energy inputs of a typical upgrader by 13% and reduce its GHG emissions by 8% (see Table 5.1). However, because upgraders are built to unique designs, not all may be able to benefit from all measures.

28 The other 30% comes from steam and electricity.

Table 5.1

Opportunities for Energy Intensity and GHG Improvements

Measure	Energy Intensity Improvements (%)	Reductions in GHG Emissions (%)
Flare and hydrocarbon losses	3	2
Heat losses to earth and water	0	0
Fuel type and use	2	1.5
Energy monitoring and management	1	0.5
Utilization efficiency	0	0
Heat exchange/integration & fired heater efficiency	3.5	2
Utilities, steam, power, cogeneration, hydrogen	0	0
Process, technology changes	1.5	1
Control systems	2	1
Total	13	8

Suncor Energy Inc. and Jacobs Consultancy Canada Inc., (2012)

The percentages in the table are based on all direct and indirect energy requirements associated with a typical upgrader.

5.5 CONCLUSIONS

The most significant environmental impact associated with oil sands upgrading is GHG emissions. While industry is exploring several options to improve the process yields from upgrading or to eliminate the need for diluent in bitumen transport, most of these technologies offer little potential to substantially reduce GHG emissions. Some, however, may have other environmental benefits. The technology with the greatest potential to reduce GHG emissions is not an upgrading technology, but rather CCS, which is examined in the next chapter.

Operators are devoting considerable effort to commercializing partial upgrading technologies. While the technologies explored differ, they share the advantage of greatly reducing or eliminating the need for diluent in bitumen transport.

6

Cross-Process Technologies to Reduce GHG Emissions

- Alternative Low Carbon Energy Sources
- Carbon Capture and Storage
- Conclusions

6 Cross-Process Technologies to Reduce GHG Emissions

Key Findings

Alternative energy sources have the potential to significantly reduce the GHG footprint of oil sands development. In particular, low carbon energy sources — hydroelectricity, geothermal, and nuclear — are still a decade or more away from wide adoption, requiring significant investment to solve technical challenges and/or to build the necessary infrastructure.

For point sources of highly concentrated CO_2 emissions, CCS offers a technically feasible set of technologies already being deployed in the oil sands and elsewhere in the world. The costs and risks associated with large-scale implementation, however, render CCS largely commercially unattractive for wide adoption in the oil sands. These costs vary substantially depending on the industrial process producing the carbon to be captured. As such, considerable research is under way on reducing these costs.

Wider adoption of CCS technologies will depend on further investment or the imposition of a higher carbon price. As carbon prices rise, however, alternative low carbon energy sources are likely to become competitive before CCS can be applied to all major sources of GHG emissions from the oil sands.

The previous three chapters reviewed a number of technologies that can reduce GHGs within mining, in situ, and upgrading processes. Cross-process technologies can further decarbonize the oil sands' environmental footprint by using low carbon energy inputs or capturing and storing carbon to prevent its release into the atmosphere. This chapter reviews the potential of both approaches to reduce GHG emissions across the oil sands industry.

Alternative energy sources have the potential to significantly reduce the GHG footprint of oil sands development. Low carbon energy sources such as hydroelectricity, geothermal, and nuclear require, however, significant investment to build the necessary infrastructure or solve technical challenges.

The Alberta and federal governments have identified carbon capture and storage (CCS) as the main approach to achieving large GHG emissions reductions from the oil sands. It could, in principle, be implemented relatively quickly as it is technically feasible and proven, as is evident from its use in the oil sands and in several regions around the world (Global CCS Institute, 2014). However, at present, carbon capture is expensive and the process is not commercially attractive, with costs varying substantially depending on the industrial process producing the carbon to be captured. Considerable research is under way on reducing the costs of carbon capture, the most expensive component of CCS.

6.1 ALTERNATIVE LOW CARBON ENERGY SOURCES

To reduce GHG emissions associated with electricity, steam, and hydrogen production, several alternative low carbon energy sources have been considered as replacements for natural gas. The most promising are hydroelectricity, geothermal, nuclear, electricity cogeneration, and coal-fired power generation with full CCS. Given the inherent challenges of intermittency and climate for wind and solar power, respectively, they are unlikely to be an economic source of concentrated energy for oil sands operations (Pembina Institute, 2009) and thus are not discussed in this section.

6.1.1 Hydroelectricity

Hydroelectric power has the potential to reduce the GHG emissions of oil sands operations. While hydro projects produce CO_2 and methane from landscape flooding (St. Louis *et al.*, 2000) and CO_2 from transmission and facility construction, these emissions are significantly lower than those from natural gas, oil, or coal. However, they may affect water regimes and downstream environments (MRBB, 2013). Although water levels vary the capacity of a hydro plant throughout the year, since water can be retained in reservoirs from the wet to the dry season, hydroelectricity can, effectively, be easily stored (Macleod, 2011). Ultimately, the electrical output from hydro systems is highly predictable (Macleod, 2011). In principle, hydro is a good source of energy for steam production for in situ operations.

While most of the 900 megawatts (MW) that hydro contributes to the grid are located in southern Alberta, 11 existing hydroelectric facilities in the Mackenzie River Basin could serve the oil sands (MRBB, 2013). While forecasts include only 200 MW of small hydro before 2024, a 1,200 to 1,300 MW project on the Slave River has been discussed (MRBB, 2013). Another option is to import hydro from British Columbia or Manitoba. For example, Site C Clean Energy Project (Site C) is a proposed third dam and hydroelectric generating station on the Peace River in northeast British Columbia (BC Hydro, 2014). Site C would provide 1,100 MW of capacity and produce about 5,100 gigawatt hours (GWh) of electricity each year. The project received environmental approvals from the federal and provincial governments in October 2014, but remains controversial. It requires an investment decision by the province and regulatory permits and authorizations before it can proceed to construction (BC Hydro, 2014). Supplying oil sands operations would require building transmission links and other infrastructure.

6.1.2 Geothermal Energy

Geothermal energy has the potential to reduce both the production costs and GHG emissions associated with oil sands production (Majorowicz *et al.*, 2012). The idea of using geothermal heat for processing was first proposed by the GeoPos consortium (Geopowering the Oil Sands), which included Suncor, Shell, Nexen, and ConocoPhillips Canada. A partnership between the Helmholtz Association of German Research Centres and the University of Alberta is currently researching the idea in more detail. Various modelling approaches have been used to determine the amount of energy produced from hot dry rock. The heat generation capacity of oil sands regions was determined using models, and the energy's potential use (in the form of hot water) for surface extraction processes was evaluated. For instance, Majorowicz *et al.* (2012) demonstrate that the hot water (50 to 60°C) needed for surface mining extraction can be from 4 to 5 km deep artificially fractured granite, and can be economically competitive with generation of the same amount of heat using natural gas.

A large degree of uncertainty around these estimates currently exists because they are based only on analytical modelling and laboratory research. Technical challenges must be overcome before geothermal energy can be scaled up for use in oil sands operations, including measuring the thermal profile, identifying permeability, calculating fracture potential, and deep hard rock drilling of 10 km (Majorowicz *et al.*, 2012). DEEP Corporation has secured a lease with the Saskatchewan government to field test the potential of geothermal energy in the Deadwood and Winnipeg formations, areas that have similar geology to the Athabasca region (DEEP, 2014). DEEP plans to drill into deep aquifers and pipe the hot water into a turbine to generate electricity. This technology is currently being used globally, with the United States leading with about 3,400 MW of geothermal energy production (DEEP, 2014).

6.1.3 Nuclear Energy

Nuclear power generation has the potential to significantly reduce the oil sands' GHG footprint. The heat generation process produces zero GHG emissions (CERI, 2008; Finan & Kadak, 2010), but the associated processes (e.g., uranium mining, power plant construction and operation) do generate a small amount of GHGs, radioactive waste material, and potential groundwater pollution (Winfield, 2007). In general, nuclear power could make steam and electricity, using some of the latter for high temperature electrolysis for hydrogen production (CERI, 2008). Two challenges are associated with using nuclear power to generate steam for in situ operations: a nuclear facility must generate steam at a sufficiently high temperature and pressure, and this steam supply needs to be portable as in situ operations are dispersed (CERI, 2008).

A number of reactor types have been considered to supply energy in the oil sands (see Table 6.1). The available evidence suggests that large reactors (i.e., Enhanced CANDU 6, ACR-700, ACR-1000, EPR-1600) have limited potential for the production of steam, but significant potential for electricity generation. For instance, Finan and Kadak (2010) examine the feasibility of the Enhanced CANDU 6 and the ACR-700. They find that the steam output of the former, 4.7 megapascal (MPa), is at too low a pressure for most SAGD projects. While the ACR-700 provides sufficient pressure (6.5 MPa), it is sized to provide steam for a project of 200 to 300k bpd, which would require a large oil sands field. However, piping the steam to the outer parts of such a field would not be possible without significant pressure drop. This would render the steam unusable for traditional SAGD (CERI, 2008; Finan & Kadak, 2010).

In terms of electricity production, both the CANDU 6 and ACR-700 were found to be suitable for 200,000 bdp surface mining projects, the current typical size in the oil sands (Finan & Kadak, 2010). CERI (2008) finds that while all four reactor types can produce adequate electricity for oil sands operators, only the ACR-100 and EPR 1600 can provide steam at the required pressure.

Table 6.1

Comparison of Reactor Types

Type	Description	Power (MWth)	2009 (MPa)	2010 ($)
Enhanced CANDU 6	Pressure heavy water reactor	2,064	4.7	N/A
Advanced CANDU Reactor (ACR-700)	Light water coolant with heavy moderator	2,034	6.5	N/A
ACR-1000	Light water coolant with heavy moderator	2,400	7.0	$6.2 billion
AREVAA EPR-1600	Light water coolant with heavy moderator	1,600	5.8	$2.4 billion
Pebble Bed Modular Reactor	Modular high temperature gas-cooled reactor	500	11	N/A
Toshiba 4S	Modular high temperature liquid metal-cooled reactor	N/A	N/A	N/A

Data Sources: CERI (2008); Finan & Kadak (2010)

Large nuclear reactors face a number of economic challenges including high capital costs, plant size, potentially high maintenance costs, large support staff, short refuelling cycles, and waste management issues. Negative public perceptions (Slovic, 2000) may also limit their deployment (see Chapter 7). Small-scale modular reactors, such as high temperature gas-cooled reactors and liquid metal-cooled reactors, are a more likely nuclear alternative for in situ operations. Finan and Kadak (2010) assess the South African-designed pebble bed modular reactor (PBMR), finding both the steam pressure and reactor size to be compatible with typical in situ projects. In addition, since PBMRs can be installed in modules, they can be added as in situ production expands. The electricity generating power and portability of the PBMR also make it suitable for most surface mining operations (Finan & Kadak, 2010).

Across both large and modular reactors, based on projections of available cost information, Finan and Kadak (2010) find that steam and electricity produced using nuclear energy, rather than natural gas, become less expensive as natural gas prices climb higher than $6.50 per 1 million British thermal units (MMBtu) and $10/MMBtu, respectively. Overall, replacing the natural gas and electricity supply to a 100,000 bdp operation with nuclear energy could reduce emissions in the region by 3.3 million metric tons of CO_2 per year of operation (CERI, 2008; Finan & Kadak, 2010). If ACR-700 or ACR-1000 were installed solely to provide electricity, CO_2 emissions would be reduced by 2.1 and 3.5 million metric tons per year, respectively (Finan & Kadak, 2010).

In sum, the need for sufficiently high steam pressure and portability makes small-scale modular reactors a possible technology to reduce the GHG emissions of the oil sands. Adoption depends heavily on their economic attractiveness, which, in turn, depends on the price of natural gas, GHG regulations, the likelihood for capital cost overruns, and public acceptability. These are discussed in Chapter 7. Large reactors have some, albeit limited, potential for the production of steam and significant potential for electricity generation.

6.1.4 Electricity Cogeneration

The rapid adoption of cogeneration in the oil sands industry, in both mining and in situ operations, has reduced GHG emission growth since 1996 (Moorhouse & Peachey, 2007). Between 1996 and 2006, cogeneration led to an estimated reduction of 7 Mt CO_2/year. Approximately 80% of this reduction resulted from conversion to natural gas for electrical energy from the more carbon intensive Alberta grid, which uses primarily coal generation. The remaining 20% was due to increased efficiency through on-site cogeneration (Moorhouse & Peachey, 2007).

ConocoPhillips Canada and Total E&P Canada are testing a gas turbine once-through steam generator (OTSG) in a pilot-scale demonstration at Surmont (COSIA, 2014b). The enabling technology is a burner that uses natural gas and hot turbine exhaust to generate electricity, which operates more efficiently than competing cogeneration configurations. Estimates show this could reduce the reliance of a given facility on the Alberta power grid, which is primarily supported by carbon intensive coal-fired power plants, resulting in a 17% per barrel reduction in the carbon intensity of bitumen products (COSIA, 2014b). This technology will have limited impact on long-term emissions, however, because the benefits will no longer exist once coal-fired plants are replaced by natural gas.

6.1.5 Coal-Fired Power Generation with Full CCS

The recent $1.24 billion SaskPower Boundary Dam Integrated Carbon Capture and Storage Project in Estevan, Saskatchewan also has the potential to reduce CO_2 emissions (SaskPower, 2012). A partnership between the Government of Canada, Government of Saskatchewan, SaskPower, and industry, this project consists of a rebuilt coal-fired power plant with CCS technology that will inject CO_2 into storage deep underground. In addition to reducing the carbon emissions for enhanced oil recovery and/or storage of deep saline aquifers, the plant will capture SO_2 and fly ash. The project will provide an estimated 110 MW of electricity and capture approximately 1 million tonnes of CO_2 per year, some of which will be liquefied and sold as fuel. Cenovus, for instance, has a 10-year agreement to purchase the captured carbon from SaskPower. At the time of this report's writing, it was the world's largest CCS project associated with thermal electricity generation (SaskPower, 2012).

6.2 CARBON CAPTURE AND STORAGE

CCS is an established suite of technologies already being applied in, for example, Saskatchewan, the United States, Norway, and Algeria. At the end of 2014, 22 large-scale CCS projects were in operation or under construction around the world (Global CCS Institute, 2014). CCS is applicable to several large industrial processes such as thermal generating stations, fertilizer plants, refineries, and cement manufacturing, but not to mobile sources (e.g., cars and trucks). Oil sands operators can thus benefit from R&D efforts in other industrial sectors as well as contribute to them.

This section describes CCS in general, and then focuses on carbon capture technologies, the most expensive component. It briefly highlights transportation and storage and considers the economics of CCS.

6.2.1 Process Description and Current Projects

CCS involves a three-step process:

1. *Capture:* This includes removal of impurities and compression, and is the most expensive step, involving a variety of industrial sources.
2. *Transportation:* This is a mature technology as in North America CO_2 is already carried by high-pressure pipeline (to maintain a single-phase flow).
3. *Storage:* Options include injecting CO_2 into a geological formation or the ocean, and converting it into a solid carbonate (CETC, 2006). Injection and storage are the least expensive components of CCS and may be profitable activities when used for enhanced oil or gas recovery (CETC, 2006).

The oil sands appear well suited for the application of CCS technology for at least four reasons. First, the production of hydrogen in upgrader processes (an important source of GHG emissions) can supply large volumes of pure, high-pressure CO_2, reducing the costs of capture. Second, as a province with a mature oil and gas sector, Alberta has a lot of storage capacity in depleted oil and gas reservoirs. These potential locations are geologically stable and deep, and the reservoir characteristics of depleted fields are well known (CETC, 2006). Deep saline aquifers or coal formations provide additional storage options in the province (ICO2N, 2009). Third, CCS can enhance oil recovery in mature reservoirs, compensating for some of the costs of CCS deployment in the short term (in the long term, enhanced oil recovery will not have the capacity to absorb all the CO_2 to be stored). The oil industry has used CO_2 injection as an enhanced oil recovery technique for many years. Fourth, the transportation distances from source to storage are relatively short, and sources of CO_2 and storage sites exist in clusters (Middleton & Brandt, 2013). Much of the infrastructure for CCS (e.g., wells, geological characterization of storage reservoirs, service industries) is already in place.

Although many of the processes involved in CCS already exist and several have been deployed on a commercial scale, CCS as a technology suite remains expensive and is not economically viable under current market conditions (see Section 6.2.4). Alberta has committed \$1.3 billion over 15 years to fund two large-scale CCS projects in the province (Alberta Government, 2014a). The federal government has allocated \$1.8 billion to CCS projects across the country (Natural Resources Canada, 2013). These projects will demonstrate the technologies involved and contribute to the required infrastructure for large-scale CCS deployment.

Shell Canada has gained conditional regulatory approval for the Quest CCS Project — a fully integrated project that would capture, transport, and store more than 1 million tonnes of CO_2 per year from its Scotford Upgrader, equivalent to 35% of the upgrader's emissions (Shell Canada Ltd., 2014). In 2011, Shell signed agreements with the governments of Alberta and Canada, securing $865 million in funding for the project. The Quest Project was awarded the world's first third-party certificate of fitness for the safe underground storage of CO_2 by international risk management firm Det Norske Veritas. It will be the world's first CCS application developed for the oil sands industry. Pending a final investment decision, injection of CO_2 will begin in 2015 (Shell Canada Ltd., 2014). The federal and Alberta governments are contributing over $550 million, roughly half the cost of Enhance Energy's Alberta CO_2 Trunk Line, for a 240-km pipeline to carry CO_2 from the Northwest Upgrader and the Agrium fertilizer plant north of Edmonton to depleting oil fields where it will support enhanced oil recovery (Enhance Energy, 2014). The pipeline is to start operations in 2015.

Taken together, these projects will reduce Alberta's GHG emissions by 2.76 million tonnes annually beginning in 2015, a little over 1% of the province's total emissions (Alberta Government, 2014a). Alberta's investment in CCS will also help make these technologies more accessible by providing some of the infrastructure needed to support future projects. Both funded CCS projects are required to make available technical information and lessons learned (Alberta Government, 2014a).

6.2.2 Carbon Capture

As CO_2 is already transported by pipeline and the geological and technical feasibility of carbon storage is being demonstrated (NETL, n.d.), the research focus has turned to carbon capture, the most expensive step in a CCS strategy (Middleton & Brandt, 2013), accounting for up to 80% of total CCS costs (ICO2N, 2009). This is the step with the greatest potential — and greatest need — for cost reduction (estimated at between 25 and 30% by 2025) (CETC, 2006). Box 6.1 highlights the four R&D priorities outlined by Canmet (2006).

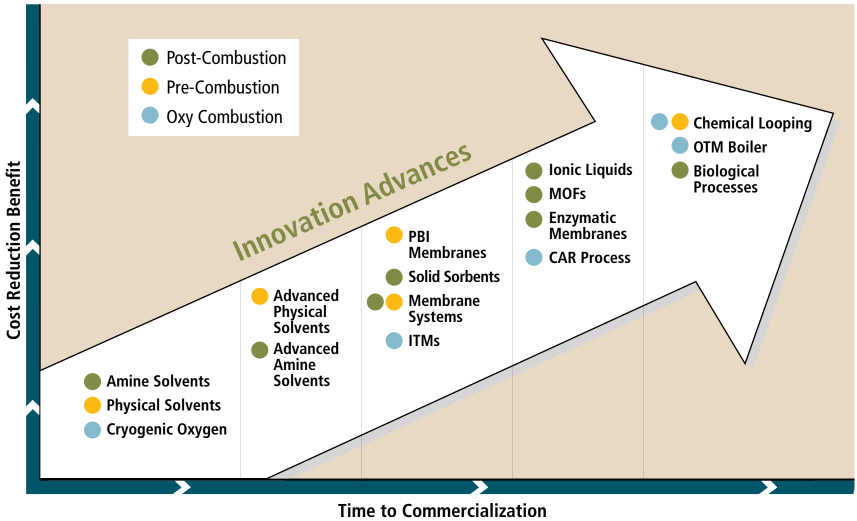
Box 6.1
R&D Priorities in Capture Technologies

Canmet (2006) identifies the following R&D priorities in capture technologies:

- development and scale-up of solvent technologies for the treatment of air-fired flue gases;
- mechanics of combustion and heat transfer, burner development, furnace design, integrated flue-gas cleaning, and CO_2 gas separation and compression in advanced integrated processes using oxy-fuel combustion;
- improved catalyst/membrane processes for pre-combustion capture of CO_2; and
- improving understanding of process chemistry to increase CO_2 concentrations in flue gases from major industrial processes.

There are four main systems for separating and capturing CO_2 in large stationary fossil fuel operations (CCS is not suitable for mobile sources): pre-combustion, post-combustion, oxy-fuel combustion (combustion in an oxygen-rich environment), and chemical loop combustion (also called industrial separation). Each has its own applications, advantages, and disadvantages (Ordorica-Garcia *et al.*, 2012). Figure 6.1 shows the relative status of these technologies.

Specific CO_2 capture technologies include absorption, adsorption, membrane, and cryogenic technologies, each involving a variety of possible processes (CETC, 2006). Chemical absorption commonly relies on organic amines for its solvents although some processes also use inorganic chemical solvents. Adsorption technology is a simple technology that is being developed in at least two variants, electrical swing adsorption and vacuum swing adsorption. Two basic membranes are being considered for CO_2 capture: gas separation membranes and gas absorption membranes. These technologies can be deployed in both pre- and post-combustion processes (Ordorica-Garcia *et al.*, 2012). Cryogenic separation is used primarily in gas streams with already high CO_2 concentrations (CETC, 2006). All pre-combustion technologies have been used commercially for years, but usually in industrial processes other than CCS (Ordorica-Garcia *et al.*, 2012).



Reproduced from *International Journal of Greenhouse Gas Control*, 2(1), Figueroa, J. D., Fout, T., Plasynski, S., McIlvried, H., & Srivastava, R. D. "Advances in CO_2 capture technology—The U.S. Department of Energy's Carbon Sequestration Program." 9-20, 2008, with permission from Elsevier

Figure 6.1

State of Capture Technologies

The figure plots cost reduction benefit versus time to commercialization for a range of CCS technologies. It demonstrates that as these technologies advance, significant cost reductions can be realized.

Several pre- and post-combustion systems have been proved at a commercial scale around the world and new technologies are being tested. Oxy-fuel technology is already commercial in several industrial applications (e.g., glass industry) and is being demonstrated in a retrofitted OTSG boiler (25 to 50 MMBtu) at a Suncor SAGD facility. Although the unit energy consumption to produce oxygen by cryogenic processes continues to decrease, a step change technology is needed for CO_2 sequestration applications (Kobayashi & Van Hassel, 2005). CCEMC is funding an OTSG oxy-fuel demonstration project at Christina Lake. This system's main drawback is the cost and energy required for oxygen production, but it offers the advantage of generating a concentrated stream of CO_2 (CCEMC, 2014). A CERI study concludes that retrofitting natural gas boilers with an oxy-fuel system is likely too expensive to be adopted widely in SAGD production in the near future (Walden, 2011).

Chemical looping combustion is a less mature technology with a longer path to commercialization than the three described above. An industry consortium led by Cenovus, and with support from CCEMC, is demonstrating the technology at a 10 MW plant at a SAGD site. The projected CO_2 capture cost is 40 to 50% lower than post-combustion amine scrubbing (Isaacs, 2014).

HTC CO_2 Solutions Inc. has patented an enzyme-based catalyst that lowers the cost of CO_2 capture relative to current carbon capture technology, in part thanks to a 33% improvement in energy consumption for capture of CO_2 emissions from a typical OSTG (CO_2 Solutions, 2014). CO_2 Solutions Inc. will now proceed to the pilot demonstration phase to validate process performance in the field by testing a 15-tonne CO_2/day operation with Husky Energy at its Pike Peaks South heavy oil project in Saskatchewan (CO_2 Solutions, 2014). Other enzyme-enhanced solvent research is under way (e.g., zinc metallic organic framework with amine-lined pores). Research on polymer membrane separation is also being conducted in the United States and Norway.

Given that oil sands production and upgrading use different processes, the most suitable CO_2 capture technology will vary. Post-combustion (hot water and power generation processes) technology may be most appropriate for mining, oxy-fuel combustion (OTSG process) for SAGD, and pre-combustion (hydrogen production process) for upgraders. For future SAGD projects, chemical looping combustion may become a more attractive option as the technology matures since it does not require the expense of an oxygen separation plant (Ordorica-Garcia *et al.*, 2012).

In 2013, CCEMC launched an international challenge to technology developers to submit proposals to convert CO_2 into valuable carbon-based products. CCEMC and its venture partners have provided up to $35 million to fund the development of promising technologies with breakthrough potential that can make significant inroads towards the creation of new products and markets, and subsequently reduce GHGs through the development of a carbon-based economy (CCEMC, 2013b).

6.2.3 Transportation and Storage

Although most of the R&D effort in CCS has been focused on developing cheaper capture technologies, there are R&D needs in both pipeline and storage technologies. These are mostly aimed at defining optimal pipeline parameters for CO_2 transportation, site identification and characterization, and storage integrity for CO_2 sequestration (CETC, 2006). CCS raises environmental and safety risks similar to those of the upstream oil and gas industry (The ecoENERGY Carbon Capture and Storage Task Force, 2008). The biggest risk is that CO_2 injected underground will leak over time. While this risk is believed to be very small, it is difficult to quantify and has frequently been a source of public concern (CETC, 2006).

6.2.4 Economics

CCS is a capital intensive technology that requires large upfront investments to capture, dehydrate, compress, transport, and inject CO_2. It is also an energy intensive technology: CCS reduces the net energy gain further in the oil sands where the energy input for production and upgrading is already high.

The cost of carbon capture depends on the industrial application being considered and is generally a function of the concentration of CO_2 in the gas stream being processed (CETC, 2006). For example, upgraders use roughly similar volumes of natural gas for hydrogen production, and for steam and electricity generation (Ordorica-Garcia *et al.*, 2012). Hydrogen produced through gasification yields a concentrated (and therefore relatively cheap to capture) pre-combustion CO_2 stream. Burning natural gas to generate power, however, yields a diluted (and therefore relatively expensive to capture) post-combustion stream. The existence of varied stream compositions and distributed CO_2 sources within a single facility increases capture costs (Kheshgi *et al.*, 2012).

Cost estimates for CCS range widely. This is a function of the large number of applications and industrial processes involved, the commercially immature nature of the technology (even though some of its individual components have a long track record) (Kheshgi *et al.*, 2012), and the difficulty in some cases of isolating incremental costs attributable to CO_2 capture (ICO2N, 2011). While some expect that costs will drop by 25 to 30% with experience, standardization, and process optimization (CETC, 2006), others note that initial cost estimates of technologies under development are often optimistic (Kheshgi *et al.*, 2012).

Several additional economic considerations are worth noting. First, CCS competes with other decarbonization technologies, and alternatives such as energy efficiency and fuel substitution may become economic before large-scale CCS (Walden, 2011). Second, retrofitting an existing facility to capture CO_2 is generally more expensive per tonne of CO_2 sequestered than designing a new one to include CCS from the start (CETC, 2006; Kheshgi *et al.*, 2012). This is important in a fast-growing industry such as the oil sands where the rapid pace of development may "lock in" existing capital equipment and processes. Third, as a technology with economies of scale (Kheshgi *et al.*, 2012), there is an opportunity for industry collaboration to share transportation and storage costs, particularly for smaller CO_2 producers.

Published cost estimates are difficult to compare since they have been prepared at different times for different processes and estimated using different methodologies (Table 6.2). Nonetheless, they confirm that the costs of capture dominate overall costs, and that the 2014 Alberta carbon price of $15/tonne for large emitters provides an insufficient incentive for the widespread adoption of CCS technologies.

Table 6.2

Estimated Costs of CCS

Source	Estimate ($ per tonne)
Intergovernmental Panel on Climate Change (2005)*	Capture: US$5–$55 (hydrogen production) Transportation: US$1–$8 (250-km pipeline) Storage: US$0.6–$8 Total: US$6.60–$71
Canmet (2006)	Capture: $13–$80 Transportation: $6 (650-km common carrier) Storage: $3–$9 Total: $22–$95
ICO2N (2009)	$70–$90 (hydrogen production at upgraders) $160–$250 (SAGD)
IEA and UNIDO (2011)	US$35–$70 (lower where associated with enhanced oil recovery)

* As cited in Kheshgi *et al.* (2012)

6.2.5 Policy and Regulatory Framework

As a young technology requiring large upfront investments, CCS raises a number of financial, environmental, and technical risks. In addition, CCS research is expensive and requires a collaborative effort (CETC, 2006). Governments considering CCS have therefore been developing sets of rules that identify the permitting, operating, monitoring, and remediation requirements associated with the technology (CETC, 2006). Alberta undertook an assessment of its CCS regulatory framework in 2012, noting the need to clarify the regulatory regime and approval process, provide additional technical guidance, encourage greater collaboration among firms in the industry, and require measurement, monitoring, and verification protocols (Alberta Government, 2012b).

Several policy and regulatory issues, however, remain to be resolved, primarily around the allocation of risk (e.g., long-term storage leaks) and carbon pricing. Many experts have argued that governments need to provide additional incentives to reduce cost and share investment risk (ICO2N, 2009; IEA & UNIDO, 2011).

6.3 CONCLUSIONS

Alternative low carbon energy sources could potentially provide the greatest reduction in GHG emissions if widely adopted. Low carbon electricity could open up new opportunities for in situ electrification technologies as described in Chapter 4. Barriers for each low carbon source, however, must be overcome, which makes this a longer-term solution for oil sands development.

With the current state of capture technology, the use of CCS is most applicable to hydrogen production in upgraders, which yields a high-quality pre-combustion CO_2 stream. Large thermal generation plants at upgraders, which release post-combustion CO_2, could be next in line. As noted above, the practical considerations in retrofitting existing upgraders may limit CO_2 capture below theoretical limits to between 20 and 40% of actual CO_2 emissions. More expensive would be the capture of CO_2 from in situ projects because these represent smaller and geographically dispersed sources of emissions. As with all the other technologies reviewed in this report, the availability of CCS in the future will depend on the progress made today. Large-scale deployment is unlikely to occur without a reduction in CO_2 capture costs, a supportive policy and regulatory framework, and infrastructure.

Wider deployment of CCS technologies will depend on further government investment or the imposition of a higher carbon price. As carbon prices rise, however, alternative low carbon energy sources are likely to become competitive before CCS can be applied to all major sources of GHG emissions from the oil sands.

7

Accelerating the Adoption of Leading Oil Sands Technologies

- Factors Influencing Technology Adoption in the Oil Sands
- Estimating Potential Reductions in the Environmental Footprint from Technologies
- Towards Reducing the Absolute Footprint of Oil Sands Production
- Conclusions

7 Accelerating the Adoption of Leading Oil Sands Technologies

Key Findings

Despite its decline on an intensity basis in several areas, the absolute environmental footprint of the oil sands has continued to grow due largely to increased bitumen production that has outstripped incremental improvements in environmental performance. If the environmental footprint is to be significantly reduced, industry-wide adoption of the best technologies will be needed.

Technology adoption in the oil sands is influenced by resource input factors (e.g., reservoir quality, natural gas prices); business factors (e.g., scale of investment, development time, investment cycle); and policy factors (e.g., regulation, taxation, public investment in technology development).

In the near to midterm, no single suite of existing technologies can bring about absolute reductions in the environmental footprint at current production growth rates. For GHGs to be reduced to levels below the U.S. average crude level and other international sources, more transformative technologies, such as solvent-based extraction or use of hydro power, are likely to be needed.

To increase the rate of technology adoption, industry can increase R&D spending, enhance collaborative innovation, and set performance targets. For their part, governments can develop a more complete regulatory regime that places a higher value on carbon, clarifies future water treatment and discharge standards, and supports a design-for-closure approach. More generally, this requires creating the conditions for a healthy and dynamic innovation ecosystem.

Ultimately, a greater emphasis is required on fundamental scientific research and knowledge transfer and on collaboration between academia, industry, and government, where research is multidisciplinary and partnerships are fully transparent. This can be accomplished with multiparty collaborations on large demonstration projects.

For the last half-century, the oil sands industry has relied on technological innovation to access a growing portion of Alberta's bitumen resources. Over this time period, the industry has introduced a series of innovations, starting with the Clark Hot Water Extraction Process and including technologies such as froth treatment processes for surface mining, and various forms of thermal and solvent-assisted processes for in situ production (e.g., CSS, SAGD). These innovations have enabled the industry to increase production several-fold and reduce its environmental footprint on an intensity basis. As the Panel has described in previous chapters, the oil sands industry continues to invest in technological innovations expected to further reduce its environmental impact per barrel.

Yet, as described in Chapter 2, the oil sands industry's overall environmental footprint has continued to expand alongside the growth in production. The investments made by the industry over the last several decades have led to significant reductions in the environmental footprint on a per barrel basis (i.e., on an *intensity* basis). However, the *absolute* environmental footprint of the oil sands industry continues to grow. The Panel believes that the central environmental challenge facing the industry is reducing its absolute footprint.

As reviewed in Chapters 3 to 6, many technologies at various stages of development have the potential to reduce the absolute footprint. A number of resource input, business, and regulatory factors, however, may impede technology adoption. Impediments aside, there are reasons to believe that the current level of investment and adoption rate for environmental technologies is too low. From a firm's perspective, investing in environmental technology often represents a cost only, with limited benefit to the firm, which is predominantly accountable to its shareholders. The academic literature is clear that market forces alone often provide insufficient incentives, leading to firms underinvesting in environmental technologies relative to what is optimal from a societal perspective. Overall, these two issues — impediments to innovation and failure to internalize environmental costs — limit industry's ability to respond to the central environmental challenge. This creates a wedge between the potential of a technology and its actual impact on reducing the absolute environmental footprint.

This chapter estimates the potential of the most promising technologies to reduce the environmental footprint of oil sands production for the five impacts profiled throughout this report: GHG emissions, air pollutants, water quantity and quality, tailings, and land use. In doing so, it draws on the baseline footprint data presented in Chapter 2 and on performance estimates, where available, from Chapters 3 to 6. After reviewing the factors that influence the adoption of technologies, the chapter explores how these can either impede or support adoption of particular technologies within each impact category.

7.1 FACTORS INFLUENCING TECHNOLOGY ADOPTION IN THE OIL SANDS

The degree to which individual firms adopt technologies is influenced by a mix of resource input factors such as the price of natural gas, business factors that influence technology investment decisions, and, finally, the regulatory and policy environment as defined by the provincial and federal governments.

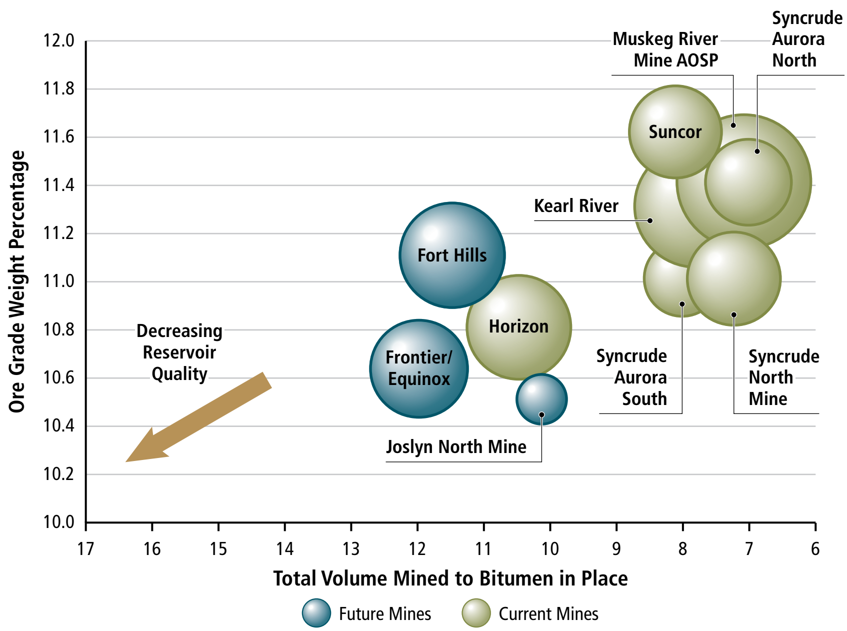
These factors collectively have both positive and negative influences on the adoption of environmental technologies in the oil sands industry. They may apply more to some impact categories than others (e.g., carbon incentives for GHGs, declining reservoir quality for tailings, water, and land), and more to some technologies than others (e.g., natural gas prices for nuclear power). The impact of these factors also varies, to a degree, across individual firms. And while no factor is so prominent as to prevent or guarantee adoption on its own, taken together, these factors play a critical role in determining the potential of technologies to reduce the footprint of oil sands production.

7.1.1 Resource Input Factors

Reservoir Quality

The nature of oil sands reservoirs has important implications for technology adoption. Since oil sands deposits are heterogeneous, varying in quality and viscosity, production techniques that are effective in one place may not be in another. This limits the diffusion of specific innovations across the oil sands region. For example, producers must customize solvent-assisted processes used for in situ recovery to suit their specific geological conditions (e.g., by using different solvents, different concentrations, and different injection rates). Similarly, a range of technologies is being developed to manage fluid fine tailings because no single solution can address the full scope of materials to be treated.

The heterogeneous nature of oil sands geology is also apparent in the progression of development from the most accessible deposits, richest in bitumen, to lower-quality deposits that are more technologically challenging and expensive to recover. Figure 7.1 shows how the reservoir quality of new mines differs from that of established mines. Since larger environmental impacts are often associated with harder to develop deposits, these impacts can be expected to grow without further technological improvement as operators gradually develop less attractive deposits that are deeper, thinner, less permeable, and with lower bitumen saturation. For example, deep deposits accessible through in situ recovery techniques may need higher energy inputs to produce and process them; surface mines accessing reserves with lower bitumen concentrations have to process more clays per barrel of bitumen, leading to the production of more fluid fine tailings.



Reprinted with permission from IHS Energy, Special Report: Oil Sands Technology: Past, Present, and Future (2011)

Figure 7.1

Trends in Reservoir Quality

The figure highlights that the reservoir quality of current mines is greater than future mines. New mines typically have lower ore grade (which measures how heavily soaked the sand is with bitumen), and higher ratios of total volume mined to bitumen in place (TV:BIP). A low TV:BIP is most economic. Since greater environmental impacts are associated with lower reservoir quality, it follows that further oil sands development will add an increasing amount to the absolute environmental footprint.

Natural Gas Prices

Natural gas is an important resource input that affects the production and environmental impact of the oil sands. Relatively inexpensive and abundant (CCA, 2014a), natural gas is widely used to generate electricity, steam for in situ production, and hydrogen for upgrading. Its price is therefore a key determinant of which technologies are the most economically attractive for steam production and upgrading. While natural gas is a relatively clean fuel compared with coal or oil, its low price has made some in situ production possible that would not be economic otherwise (Gates & Wang, 2011). The low price also discourages investments in solvent-assisted in situ recovery, low carbon power, and energy efficiency, all of which would reduce GHG emissions. Predicting energy prices is always a hazardous proposition, but the availability of large shale gas reserves in North America is likely to moderate future natural gas price increases in the short to medium term (CCA, 2014a, 2014b).

7.1.2 Business Factors

When considering investment in an environmental technology, firms assess its expected future return relative to other investments, both environmental and non-environmental, in their portfolios (Gillingham *et al.*, 2009). This requires examination of a complex set of factors, including desired production or output levels, changes in input and other operating costs related to new technologies, expected energy prices and revenue, environmental performance of the technology, policy changes (i.e., regulations and taxes), and social factors. Moreover, firms differ in significant ways that affect their behaviour, including size, age, internal organization and management structure, risk and time preferences, internal values and goals, transparency, and history. These differences influence their propensity to adopt environmental technologies. Firm heterogeneity is one of the factors that determine the rate of technology adoption across an industry (Miller & Côte, 2012; CCA, 2013a).

Scale and Life Cycle of Oil Sands Projects

The scale and life cycle of projects influence the adoption of new technology. Indeed, the highly capital intensive nature of oil sands technology investment, particularly in surface mining, has important implications for new technology demand because it imposes large financial risks, including high costs for failure.[29] Operators become more risk averse as costs increase, operating margins decline, and projects become more technologically challenging (Neal, 2007). In surface mining in particular, operators tend to select well-proven technologies rather than innovative technologies to ensure promised performance and to maximize the chances of regulatory approvals (Gray, 2010).

In general, uncertainty over the performance of a technology tends to induce firms to delay investment decisions (Bernanke, 1983; Kilian, 2008). The reluctance to embrace a new technology until it has established a successful track record is not limited to the oil sands and is present in the North American oil industry as a whole. A background study for the U.S. National Petroleum Council concludes that this reluctance "delays the technology maturation process, slows industry learning, and consequently stifles the flow of new products into the market" (Neal, 2007). This report notes that "many technically robust solutions are abandoned before they reach their commercial potential because of insufficient early uptake and the protracted payback period" created by technological uncertainty.

Where technologies cannot be replaced quickly — either because the investment needs to be amortized or because the technology forms an integral part of the production process — firms often postpone such "irreversible" investment

29 The financial challenges inherent in large capital projects are illustrated by examples in the oil sands of projects being abandoned or mothballed after the expenditure of several billion dollars (e.g., Joslyn North mine, Voyageur upgrader).

(Dixit & Pindyck, 1994; Popp, 2002, 2006). The result is "path dependence," which, when it coincides with a fast pace of development, as is the case in the oil sands today, may lock in existing technology and its associated environmental impacts for the life of the investment. Path dependence is less of a factor for in situ operations that are economic at smaller scales than it is for surface mining.[30]

Taken together, investment uncertainty and irreversibility render many environmental technology investments less attractive than other capital investments in the absence of other incentives. The economic research finds that firms in general tend to use a more stringent investment criterion than that of standard net present value, requiring a greater return on their capital investment (Popp *et al.*, 2010). However, net present valuation in general implies that a present dollar is worth more than a future dollar (i.e., time value of money).

In the context of oil sands, it follows that operators have an incentive to delay investment in tailings treatment and mine reclamation, for example, since this investment yields no revenue and is relatively more costly in the present. Ultimately, net present valuation does not adequately capture the cost of environmental liabilities or of the potential erosion of stakeholder and regulator confidence in a firm or the industry (Devenny, 2010). In the absence of regulations or public pressure that requires operators to make these investments today, operators may be reluctant to pay the premium to reduce the environmental footprint in the present when they can delay this expense into the future. This delayed investment increases the magnitude of the environmental footprint, which will have to be addressed later when revenues may be declining (or even non-existent). Indeed, when operators exit the industry, the public could be left with the costs of future cleanup. Present levels of financial assurance for reclamation, which stands at roughly $1 billion (Alberta Government, 2014b), is only a fraction of what is required.[31]

Development Time of Oil Sands Technologies

Time is another factor that influences business decisions on adoption or development of new technologies because bringing a technology from concept to commercialization can take 10 to 20 years or more. Numerical simulation

30 Path dependency and technology lock-in models consider how the initial choice between different variants of a new technology affects the subsequent diffusion speed of the chosen technology (Unruh, 2000; Durlauf, 2008). While there is no literature considering these effects in the oil sands, it stands to reason that the high capital costs, lengthy development times, and complexity of oil sands technologies make such effects likely. In addition, different areas of expertise and reservoir/deposit characteristics (e.g., Cold Lake vs. Peace River) may push an oil sands firm in the direction of a particular technology.

31 Currently, operators are required to post financial security (bond) to the Mine Financial Security Plan. The frequency and amount of this security has yet to be determined (Government of Alberta, 2015a). The Panel notes that calculation of the bond assumes that risks to the public purse are low when a mine has large bitumen reserves and that the required level of bonding increases as the ore body is depleted.

studies, fundamental laboratory work, scaled physical models, and field pilots are often required before commercial application can even be attempted. The successful testing of a technology through this process, particularly those involving underground operations (technologies at the surface can often be developed faster, e.g., hydrotransport) usually takes several years: the original SAGD patent, for example, was awarded in 1969, but the technology was not applied commercially until 1996. Many seemingly promising technologies are discarded along the way because they cannot be scaled up, run into unforeseen technical difficulties, or prove uneconomic. Most of the technologies to reduce the oil sands' environmental footprint described in Chapters 3 to 6 are still at an early stage of development.

These long technology adoption lead times are not unusual in resource industries. This is a problem because investments with long payback periods may not attract many investors. A study of 15 oil and gas exploration and production technologies found the time from average proof-of-concept to widespread commercial sales is about 16 years, much longer than in some other sectors (as cited in Neal, 2007).

The Technology Investment Window

Both the scale and life cycle of oil sands projects and the long development time of oil sands technologies affect the time that a new technology needs to penetrate the market (i.e., until all operators consider it among their options). The long lead times in the development and successful adoption of new technology pose a challenge for the oil sands industry as it seeks to reduce the environmental footprint of its operations. Decisions on technologies that will influence the environmental footprint of new projects up to 2035 will be made within the next 5 to 10 years. Exceptions are technologies that can be added to existing projects as retrofits (e.g., some solvent-assisted SAGD operations). Currently, there is a mismatch between the rate of investments in environmental technologies and the pace of development. While the greatest investment in production capacity will occur over the next 5 to 10 years,[32] the most promising environmental technologies will not be commercially available for approximately another decade, as noted in previous chapters. This implies that the technology investment window to reduce the environmental footprint of approved projects is small and closing.

7.1.3 Policy Factors

Governments can exert a large influence on firm behaviour through the various instruments at their command. These include regulations and taxation, public investment, and moral suasion. Government intervention is often justified on the

32 While the recent drop in world oil prices may extend that window, the drop in the value of the Canadian dollar and the shrinking differentials between heavy and light oil prices have largely insulated the Canadian oil sands industry from this drop.

basis of correcting market failures. There are two relevant market failures here. First, as already noted, firms generally underinvest in environmental technology since it often represents only a cost to a firm, with no corresponding increase in profit. Since many of the social costs of the environmental impacts from production are not priced, firms fail to internalize a *negative environmental externality*, and the market allows too much environmental impact from a societal perspective (Popp *et al.*, 2010).

Box 7.1
Tailings Regulations: AER Directive 074 and the Tailings Management Framework

The volume and composition of tailings ponds and the pace and quality of land reclamation are among the most pressing aspects of the environmental footprint of oil sands mines. As noted in Chapter 3, the technical challenges associated with dewatering tailings make progress in this area difficult and slow. While operators are committed to reducing this aspect of the environmental footprint, regulations can provide the incentives to increase investment and the adoption rate of the most promising technologies.

In 2009, the Energy Resources Conservation Board (ERCB, now the AER) released Directive 074. It committed operators to using new technologies and dedicated disposal areas to achieve a fines capture of 50% (in addition to that captured in hydraulically placed dykes and beaches) (AER, 2009). Though operators were unable to comply with the initial 2013 timeframe (Pembina Institute, 2013a), the AER concluded in a review of compliance that operators "had committed significant resources and had made material progress in achieving the performance criteria and integrated tailings management with mine planning and bitumen production."

In March 2015, the AER updated its regulation with the introduction of a new Tailings Management Framework and suspended the existing Directive 074. The stated objective of this new framework (to be implemented over two phases through to winter 2016) is to minimize fluid tailings accumulation by "ensuring that fluid tailings are treated and reclaimed progressively during the life of a project and all fluid tailings associated with a project are ready-to-reclaim within 10 years of the end of mine life of that project" (Alberta Government 2015a). By setting limits on acceptable levels of fluid tailings accumulation, the Framework is intended to encourage tailings technology innovation and adoption. Furthermore, its recognition of the potential need to consider the regulated release of process-affected water to the environment, and separate requirements for legacy tailings produced prior to January 1, 2015 are, in the Panel's view, two important departures from Directive 074.

Box 7.2
Specified Gas Emitters Regulations

Alberta was the first Canadian province to set a carbon compliance price for large emitters.* Under the SGER, facilities (which include many oil sands firms, as well as thermal generating plants and fertilizer plants) that emit more than 100,000 tonnes of GHG per year must reduce their emissions intensity by 12% from a specified base year target (i.e., not absolute amounts, but rather emissions per unit of production) (Alberta Government, 2014f). Operators that do not comply with the emissions reduction target have a choice to buy an offset or pay $15 per tonne of CO_2 emitted over the target level (i.e., the $15 applies only to the difference between the target and actual emissions) into a clean technology fund (CCEMC). CCEMC's mandate is to "establish or participate in funding initiatives that reduce GHG emissions or improve [the] ability to adapt to climate change" (CCEMC, 2013a). This fund has received $380 million since its creation in 2010, of which $234 million has now been allocated to 51 projects. With an average leverage ratio of 1 to 6.3, these projects have resulted in an investment of $1.3 billion (CCEMC, 2013a). The combined carbon emissions impact reduction of the 51 projects is estimated at over 10 Mt by 2020; if successfully adopted, the reductions attributable to these technologies could double (NineSights, 2014).

The evidence is mixed on the effectiveness of the SGER. Since it is intensity based, this carbon compliance price applies only to a fraction of the regulated firms' emissions, translating into an average cost of around $1.50 per tonne of GHG or $0.10 per barrel (Pembina Institute, 2013b). This is far below the estimated costs of CCS (see Chapter 6). Sawyer (2014) estimates that doubling the SGER (i.e., doubling the rate and the intensity target) translates to an additional cost of $0.13 per barrel. When compared with a similarly priced carbon tax or cap-and-trade regime, Leach (2012) shows that the SGER provides "identical incentives to reduce emissions intensity, weaker incentives to reduce emissions through reductions in output, and stronger incentives to improve productivity." At the time of writing this report, the SGER was due to expire in June 2015, and the carbon price that Alberta was intending to charge large emitters starting after this date was unclear.

---

* While federal GHG regulations for the oil industry have been under consideration since 2006, the Canadian government has deferred their introduction until the United States takes corresponding action (Pembina Institute, 2013c, 2014b). Given Congressional opposition to carbon taxes, U.S. GHG regulations for the oil and gas industry are unlikely in the next year (Ye, 2014); however, some jurisdictions (i.e., San Francisco, Boulder) have imposed their own (Milne, 2008). Overall, their future at the time of this report's writing is unclear (Pembina Institute, 2013c, 2014b).

Second, a firm that invests in a new technology creates benefits for other firms (i.e., a *positive technology externality*) that it may not fully capture. This can also lead to underinvestment in environmental technology and higher levels of environmental impact than desired by society (CCA, 2013a; Popp *et al.*, 2010). As such, even if policies to correct the environmental externalities are in place, the level of environmental technology investment (e.g., R&D) may still be suboptimal. The combination of negative environmental and positive R&D externalities provides rationales for policy-makers to intervene to accelerate environmental technology development and adoption (Popp *et al.*, 2010).

Policy-makers can use regulation or taxation to lead firms to internalize these two externalities (Popp *et al.*, 2010). For example, regulation can set environmental impact to the socially optimal level by imposing a limit on environmental emissions, while taxation of environmental inputs or emission levels provides a financial incentive to reduce environmental impact. In principle, these two policy choices can induce the same level of environmental footprint reduction. This is, however, dependent on a set of assumptions that are widely debated in the academic literature (Weitzman, 1974; EPA, 1999; Muller & Mendelsohn, 2007; Keohane, 2009; Metcalf, 2009). Examples of regulations related to tailings and carbon compliance pricing are discussed in Boxes 7.1 and 7.2, respectively. In addition, to increase the rate of environmental technology R&D and innovation, policy-makers can provide public investment support, thereby reducing the cost for firms (Popp *et al.*, 2010).

7.2 ESTIMATING POTENTIAL REDUCTIONS IN THE ENVIRONMENTAL FOOTPRINT FROM TECHNOLOGIES

Most of the potential technological improvements identified by the Panel are still theoretical, or based on experiments or small-scale pilot projects under conditions that do not necessarily reflect the reality of commercial application. Under actual conditions, the choice of technologies and their potential to reduce impacts are limited by engineering challenges and the factors noted above. In most cases, realizing the reduction potential from these technologies requires significant experimentation and learning on site, which will decrease the total reductions achieved over a project's life cycle. Estimating actual reductions is therefore a difficult task with many sources of uncertainty. As such, the findings presented below are indicative rather than definitive, intended only to give some insight into where the best opportunities for technologies lie.

Table 7.1 provides a summary of the potential impact area reductions from the technologies identified in Chapters 3 to 6 and discussed below. The second last column suggests the timeframe for the wide-scale adoption of a technology: near term (up to 5 years), midterm (5 to 15 years), or long term (15 or more years). The final column identifies environmental co-benefits[33] and/or trade-offs inherent in the adoption of a technology. Table 7.2 highlights the factors that impede and support technology adoption for each of the technologies presented in Table 7.1.

Table 7.1

Summary of Technological Opportunities

Environmental Footprint Contribution		Technology	Estimated Reduction[i]	Time to Wide-Scale Adoption	Co-Benefits & Trade-Offs
GHGs	In situ GHGs	Solvent-assisted technologies[ii]	15–35%	Near	• Reduced air pollutants • Potential groundwater pollution • Potential source of fugitive emissions
		Solvent-based technologies	90%	Mid	• Elimination of water/ related heating • Reduced air pollutants • Potential groundwater pollution • Potential source of fugitive emissions
		Energy efficiency[iii]	12%	Near	• Reduced air pollutants
	Surface mining GHGs	Solvent-based extraction	≈90%[iv]	Mid to Long	• Elimination of water/related heating • Elimination of tailings • Reduced air pollutants • Potential groundwater pollution • Potential source of fugitive emissions
		Mobile mining[v]	N/A	Mid	• NO_x reductions
		Haul trucks retrofits/ replacement[vi]	N/A	Near	• NO_x reductions
		Separation of froth tailings to reduce methane production	N/A	Near	• Facilitate tailings treatment and reclamation
		Energy efficiency	5%	Near	• Reduced air pollutants
	Upgrading GHGs	CCS	20–40%	Mid to Long[vii]	• Enhanced oil recovery
		Energy efficiency	8%	Near	• Reduced air pollutants
	General GHG emissions	Alternative low carbon energy sources	≈100%	Mid to Long	• Reduced air pollutants • Trade-offs dependent on energy source

continued on next page

33 Co-benefits exist when a technology reduces impact in more than one area (e.g., water treatment technologies impact tailings and water use/quality/retrofitting/replacing haul trucks and shovels reduce air emissions and GHGs).

Environmental Footprint Contribution		Technology	Estimated Reduction[i]	Time to Wide-Scale Adoption	Co-Benefits & Trade-Offs
Air Pollutants[viii]	SO_x	Haul trucks retrofits/ replacement (surface mining)	N/A	Near	• GHG reductions
	NO_x				
	PAH	Dust suppression technology (surface mining)	N/A		
	VOC emissions	Sulphur reduction technology	=60%		
Water Quantity	Surface mining freshwater withdrawal	Solvent-based extraction	=100%	Mid	• Elimination of fluid tailings • GHG reductions • Potential groundwater pollution • Potential source of fugitive emissions
	In situ freshwater withdrawal	Energy efficiency[ix]	5–10%	Near	• GHG reductions • Reduced air pollutants
Water Quality	Release of process-affected water (surface mining)	Water treatment technologies[x]	N/A	Mid to Long	• Reduced tailings pond volumes • Faster reclamation • Treated water discharge • Reduced risk of dyke breach
Tailings from Surface Mining	Seepage from tailings storage facilities	Liners for base of new impoundments For dykes, use of impervious elements such as clay cores or injected cores	N/A	Near	• Reduced risk of groundwater contamination
	Toxicity of froth tailings	Separating and treating froth treatment tailings	N/A	Near	• Facilitate reclamation • GHG reductions • Improved water quality
	Fluid fine tailings	Tailings technologies[xi]	N/A	Near to Mid	• Facilitate reclamation • Reduce risk of breach
	Legacy tailings	End-pit lakes where applicable	N/A	Near to Mid	• Passive bioremediation • Potential perpetual care and maintenance • Risk of needing to remove end-pit lakes

continued on next page

Environmental Footprint Contribution		Technology	Estimated Reduction[i]	Time to Wide-Scale Adoption	Co-Benefits & Trade-Offs
Land	Physical disturbance by surface mining during active operations	Land management	N/A	Near to Mid	• Reduced risk of groundwater contamination • Reduced sprawl, land disturbance footprint
	Physical disturbance by in situ operations and infrastructure	Land management	N/A	Near to Mid	• Reduced risk of groundwater contamination
	Land heaving	No technology[xi]	N/A	N/A	N/A

i This is on a project-by-project basis and does not include fugitive emissions.
ii This includes LASER, solvent-aided process, solvent-cyclic SAGD, and expanding solvent SAGD (Section 4.2).
iii This includes vacuum insulated tubing, boiler technology, and waste heat recovery.
iv This refers to emissions from extraction, but not from haul trucks.
v This includes mobile crushing units and mobile at-face slurrying (Section 3.1.1).
vi This includes new hauler engine technologies and autonomous haul trucks (Section 3.1.2)
vii The Shell Scotford Upgrader will begin sequestering CO_2 in 2015.
viii Also included, but not highlighted in the table: trace elements from fixed and mobile emissions sources (e.g., mercury, cadmium, nickel, vanadium) and fugitive dust/particulate emissions.
ix This includes vacuum insulated tubing, blowdown, boiler technology, and waste heat recovery.
x See Section 3.2.2.
xi See Section 3.4.

Table 7.2

Summary of Impediments and Supporting Factors

Area	Technology	Impeding Factors	Supporting Factors
GHGs	In situ solvent-assisted technologies In situ solvent-based technologies Mining solvent-based technologies	• Low value on carbon • Low natural gas price • Insufficient recovery rates of solvent • Heterogeneous reservoir quality	• Increase the value of carbon • R&D to improve solvent recovery • Monitor and understand groundwater impacts
GHGs	Mobile mining	• Low value on carbon • Only available for new surface mines	• Increase the value of carbon • Standards for new equipment
GHGs	Haul trucks retrofits/replacement	• Low value on carbon	• Increase the value of carbon • Truck emission standards
GHGs	CCS	• Low value on carbon • Cost • Capture technology development • Inadequate CCS infrastructure	• Increase the value of carbon • R&D to lower the cost of capture technologies • Build more CCS infrastructure
GHGs	Alternative low carbon energy sources	• Low value on carbon • Low natural gas price • High capital cost of infrastructure • Public perceptions	• Increase the value of carbon • Stakeholder consultations to understand public concerns
GHGs	Energy efficiency	• Low value on carbon • Low natural gas price	• Increase the value of carbon • Standards for new equipment
Air	Haul trucks retrofits/replacement	• Cost	• Truck emission standards
Air	Dust suppression technologies	• No technological impediment	• Regulations
Water Quantity (mines)	Solvent-based technologies	• Insufficient recovery rates of solvent • Heterogeneous reservoir quality	• Greater clarity about future water treatment guidelines and discharge standards • Tailings regulations • R&D to improve solvent recovery and water treatment technologies

continued on next page

Area	Technology	Impeding Factors	Supporting Factors
Water Quality (mines)	Water treatment technologies	• Lack of water treatment guidelines and discharge standards • Declining reservoir quality • Treatment technology development	• Greater clarity about future water treatment guidelines and discharge standards • Tailings regulations • R&D to improve solvent recovery and water treatment technologies
Tailings from Surface Mining	Tailings technologies	• Growing volume of tailings • Lack of water treatment guidelines and discharge standards • Declining reservoir quality • Technical challenge with dewatering	• Greater clarity about future water treatment guidelines and discharge standards • Tailings regulations • Separate froth treatment tailings • R&D to improve dewatering • Integrate closure and reclamation in the design of tailings disposal facilities
	Separating froth treatment tailings	• Cost	• Easier future water treatment
Land	Land management	• Growing volume of tailings • Declining reservoir quality • Limited collaboration • Limited knowledge of habitat and landscape	• Tailings regulations • Reclamation monitoring • Standards for new mines • Basic research in ecology and landscape design • Stakeholder consultations to reach agreement on what is acceptable
Solid Wastes	Coke and sulphur	• Cost • No technological	• Improved transportation infrastructure

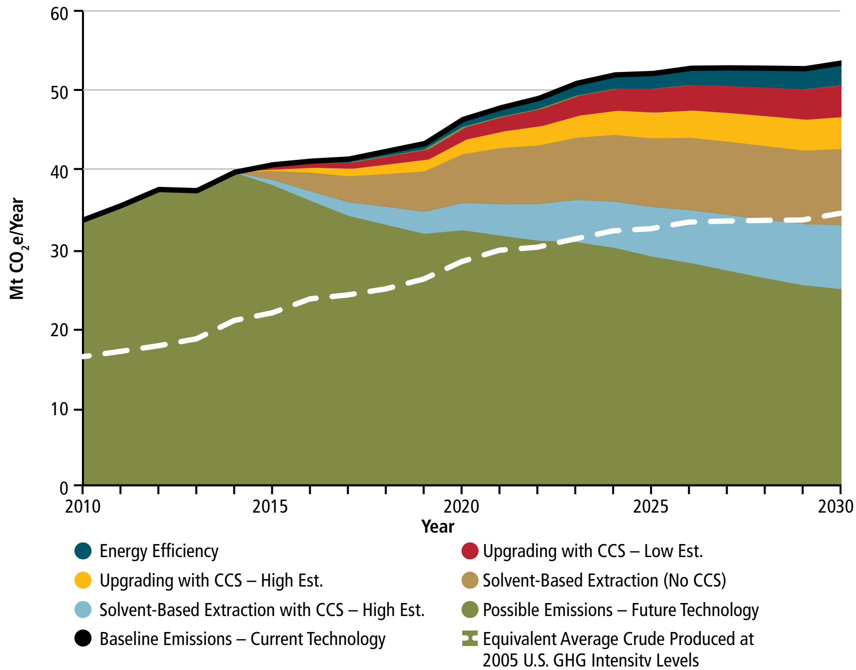
7.2.1 Reducing GHG Emissions

GHG emissions are the most pressing component of the environmental footprint of the oil sands from a global perspective. As noted in Chapter 2, while GHG emissions have fallen on a per barrel basis, total emissions are projected to grow alongside increasing production. Absolute reductions will enable Canada to meet its international climate change obligations and to help ensure that oil sands operators maintain their social licence to operate. The technologies likely to have the greatest impact on reducing these GHG emissions are the mid- to long-term, transformative technologies, notably solvent-based extraction, CCS for upgrading, and alternative low carbon energy sources like hydro, geothermal, and nuclear. In the near to midterm, reductions are achievable through technological developments aimed at energy efficiency, mobile mining technologies and haul truck retrofits or replacement for surface mining, and solvent-assisted technologies for in situ operations.

Figures 7.2 and 7.3 illustrate the potential reductions in GHG emissions resulting from different combinations of technologies summarized in Tables 7.1 and 7.2, for surface mining and upgrading, and in situ operations, respectively. They represent best-case scenarios that assume widespread adoption of technologies by 2030. Each wedge in the figures represents the potential reduction from adopting a given technology such that when they are added together, they overlap each other.[34] Since many assumptions are necessary when making such projections (see Figure 7.2 and 7.3 descriptions), these figures are intended only to be indicative of the magnitude of GHG reductions that might be possible through various technologies based on today's estimates. It excludes alternative energy sources, which could result in significant reductions in emissions, but which are longer-term solutions.

For comparison, the figures also include a dotted line showing what the GHG emissions would be if all the volume of oil sands crude was produced at a GHG intensity comparable to the intensity of an average barrel of crude produced in the United States today. As Figure 7.2 shows, GHG emissions can only be brought to the approximate level of U.S. average crude through solvent-based approaches matched with CCS applied to upgrading. Similarly for in situ oprations (Figure 7.3), solvent-based extraction processes would also be needed for GHG emissions to be lower than those produced from U.S. average crude.

34 For example, the reduction from solvent-assisted in situ operations where the low reduction case is slightly larger than the reduction from energy efficiency.



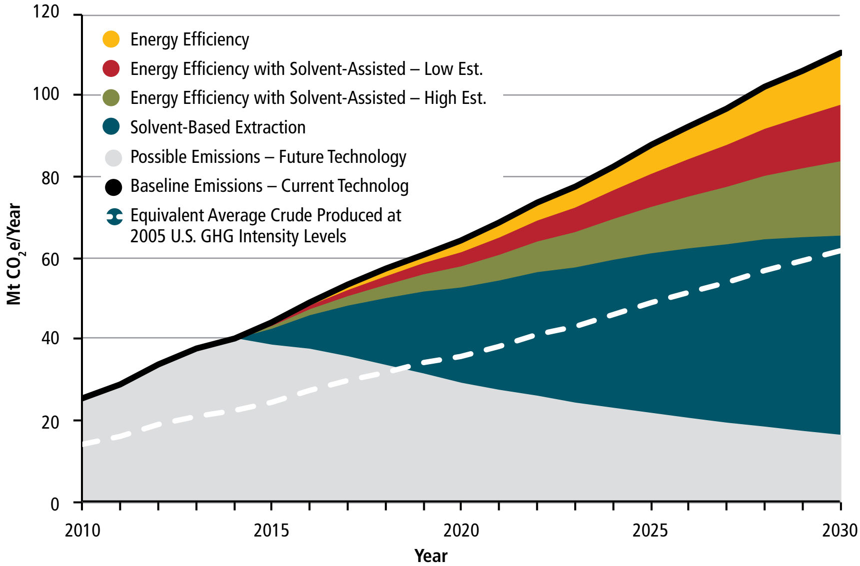
Data Sources: Calculations use estimates from Table 7.1; emission factors from Charpentier *et al.* (2011), Bergerson *et al.* (2012), and IHS Energy (2014); and production forecasts from CAPP (2014a)

Figure 7.2

Possible GHG Reductions for Surface Mining and Upgrading

The figure indicates the potential GHG reductions for surface mining and upgrading achievable from the technologies described in Table 7.1. The baseline forecast (solid black line) assumes no technological change. The dotted line plots the projected emissions that would result if oil sands crude was produced and upgraded at the same 2005 GHG intensity level as the average barrel produced in the United States. The first level of reductions (dark blue area) comes from energy efficiency improvements only, which are assumed to be achievable irrespective of new technologies implemented. These improvements are assumed to be 5% and 8% for mining and upgrading, respectively, in total across the full time period. Next are the reductions achievable from the adoption of CCS for all future upgraders alone (red area) and for all future upgraders and retrofits of existing upgraders (yellow area). Finally, the reductions from the adoption of solvent-based technologies for mining are shown, both without (tan area) and with CCS (light blue area). The green area plots the level of emissions that will occur with the adoption of all the technologies described above. Other assumptions for the figure include the following:

- Stable average reservoir conditions are assumed.
- Upstream GHG emissions of solvent production are excluded.
- For solvent-based mining, after 2020, all new mining projects use solvent-based extraction; no retrofitting for solvent-based extraction is assumed.
- All existing upgraders will be retrofitted between 2025 and 2030 for CCS.
- Aggregated forecasts overestimate reduction potential since some sources will not be affected by new technologies used (e.g., fugitive emissions, emissions from haul trucks).
- U.S. average emission factor of 52 (production and upgrading) (IHS Energy, 2014) assumed constant through to 2030.



Data Sources: Calculations use estimates from Table 7.1; emission factors from Charpentier *et al.* (2011), Bergerson *et al.*(2012), and IHS Energy (2014); and production forecasts from CAPP (2014a)

Figure 7.3

Possible Reductions in GHG Emissions for In Situ Production

The figure indicates the potential GHG reductions for in situ production achievable from the technologies described in Table 7.1. The baseline forecast (solid black line) assumes no technological change. The dotted line plots the projected emissions that would result if oil sands crude was produced at the same 2005 GHG intensity level as the average barrel produced in the United States. The first level of reductions (yellow area) comes from energy efficiency improvements only, which are assumed to be achievable irrespective of new technologies implemented. These improvements are assumed to be 12% in total across the full time period. Next are additive reductions from solvent-assisted technologies, which include low (red area) and high (green area) reduction estimates that reflect the range of stated performance improvements. Finally the reductions from the adoption of solvent-based technologies are shown (dark blue area). The grey area plots the level of emissions that will occur with the adoption of all the technologies described above. Other assumptions for the figure include the following:

- Stable average reservoir conditions are assumed.
- Upstream GHG emissions of solvent production are excluded.
- For solvent-assisted, all new in situ projects after 2015 use solvent-assisted technology; existing projects will be retrofitted by 2030.
- For solvent-based, all new in situ projects between 2015 and 2020 use solvent-assisted extraction. After 2020, all new in situ projects use solvent-based extraction; no retrofitting for solvent-based extraction is assumed.
- Aggregated forecasts overestimate reduction potential since some sources will not be affected by new technologies used (e.g., fugitive emissions, emissions from haul trucks).
- U.S. average emission factor of 52 (production and upgrading) (IHS Energy, 2014) assumed constant through to 2030.

Adoption of GHG Technologies: Impediments and Supporting Factors

The most prominent impediment to the adoption of GHG technologies is the low value currently placed on carbon, which fails to provide a sufficient incentive for firms to internalize carbon emissions and thus reduce their environmental footprint. This partially precludes CCS from being economic, places low carbon technologies (e.g., hydro) at a disadvantage vis-à-vis natural gas, and discourages the more aggressive use of solvents during in situ production.

Costs are a major impediment to the adoption of many of the technologies noted above. The price of natural gas is a key determinant of what technologies are economically attractive in steam production and upgrading. The recent low price has discouraged the adoption of technologies to reduce GHG emissions.

The relatively low recovery rates of solvents increase the costs associated with solvent-assisted and solvent-based in situ technologies. Major capital expenditures associated with infrastructure have rendered CCS too expensive for wide-scale adoption. For modular nuclear reactors, high and uncertain upfront capital costs and uncertain operating costs represent a major disincentive for oil sands operators.

Other specific impediments exist for each of the five technologies mentioned. The large-scale application of solvent-based technologies is some years away, with further field trials required to ensure that recovery rates are economic and with additional environmental monitoring required to demonstrate that groundwater is not contaminated. Moreover, the application of particular solvent-assisted and solvent-based technologies is limited by the heterogeneity of oil sands reservoirs. The slow recovery from the 2008 recession and the lack of first-mover advantage discouraged investors and developers of CCS technologies, respectively. CCS technology is expensive to develop and the continuing uncertainty about the timeframe for its deployment is a further disincentive to private investors (IEA, 2014). An impediment specific to modular nuclear is the public's negative perception of this technology and their concerns about public safety, management of radioactive waste, and cost overruns.

While the impediments to the adoption of these technologies are real, possible avenues to overcome them are noted in Table 7.2. Policy-makers can use either regulations or taxation to place the appropriate value on carbon to encourage adoption of all five technologies. In 2014, the International Monetary Fund (IMF) noted that "the principle that fiscal instruments must be center stage in 'correcting' the major environmental side effects of energy use is well established" (IMF, 2014). The IMF recommended that its member states adopt revenue-neutral taxes on fossil fuels[35] to combat climate change and air pollution. The Panel notes that while Alberta does have carbon (compliance) price, it is not sufficiently high to motivate the level of technology adoption necessary to provide the absolute reductions in GHGs required to meet international obligations.

Additional R&D can help address the technical challenges associated with solvent recovery for solvent-assisted and solvent-based technologies, capture technologies for CCS, and the development of electricity-based extraction technologies that could open up a path for low carbon energy sources. This will reduce the costs associated with these technologies, making each of them more economically viable while enforceable standards for new projects will provide incentives for energy efficiency and mobile mining and transportation technologies. Government investments in CCS infrastructure will reduce the uncertainty around its commercialization.

7.2.2 Reducing the Emission of Air Pollutants

As detailed in Chapter 2, the point sources of air pollutants from oil sands production are well known. NO_x and SO_x are released during electricity and steam generation and from mobile sources, mostly large haul trucks and mining equipment. Monitoring of these emissions has demonstrated that both are declining. However, the impact on local air quality of non-point sources, like PAHs from haul roads, fugitive emissions from tailings ponds, and from upgrader stacks, is poorly understood.

Dust suppression technologies provide an immediate and relatively straightforward way to reduce the impacts on air quality (Chapter 3). In surface mining, retrofitting and replacing haul trucks can reduce NO_x and SO_x. Both classes of technologies are currently commercial. Their wide adoption in the oil sands is a relatively low-hanging fruit for the industry.

Adoption of Air Technologies: Impediments and Supporting Factors

Compared with GHGs, tailings, water, and land, there are no major impediments to the adoption of dust suppression technologies and retrofitting and replacing haul trucks. However, reducing emissions from haul trucks will likely reduce truck efficiency and increase downtime in servicing and maintenance, thus increasing GHG emissions (M.J. Bradley & Associates, 2008). This is an important trade-off. Finally, it is difficult to assess the impact on air quality from non-point source emissions without additional air monitoring.

---

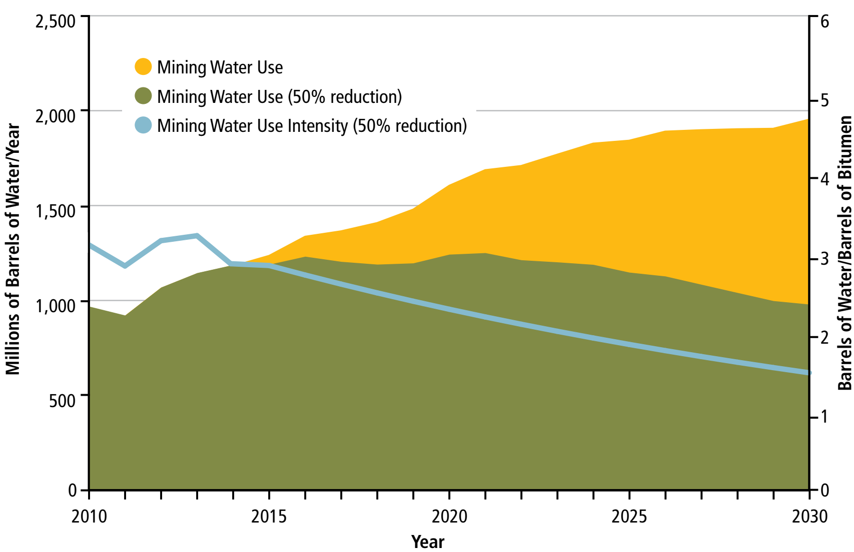
35 A revenue neutral tax offsets an increase of a tax in one area, such as the consumption of fossil fuels, by an equivalent decrease of a tax in another area, e.g., income taxes. British Columbia has implemented a revenue-neutral carbon tax of $30 a tonne.

Standards for new mines can provide the incentive for firms to retrofit and replace haul trucks and adopt dust suppression technologies. Additional monitoring of non-point sources will provide a more accurate picture of air impacts.

7.2.3 Water Quantity and Quality: Reducing Freshwater Withdrawals and Improving Process-Affected Water Treatment

At present, freshwater availability is not a major constraint for oil sands development. Water quantity may become a local environmental issue as water demand increases with surface production growth and if climate change reduces the flow of the Athabasca River. Freshwater withdrawals could be reduced if solvent extraction technologies were implemented in surface mining and in situ production (Chapters 3 and 4).

The quality of process-affected water is a key issue for the oil sands since it increases the volume and composition of tailings and slows landscape reclamation. Technologies to treat process-affected water, described in Chapter 3, include adsorption, micro- and ultrafiltration, nanofiltration and reverse osmosis, biological treatments, advanced oxidation, and treatment wetlands.

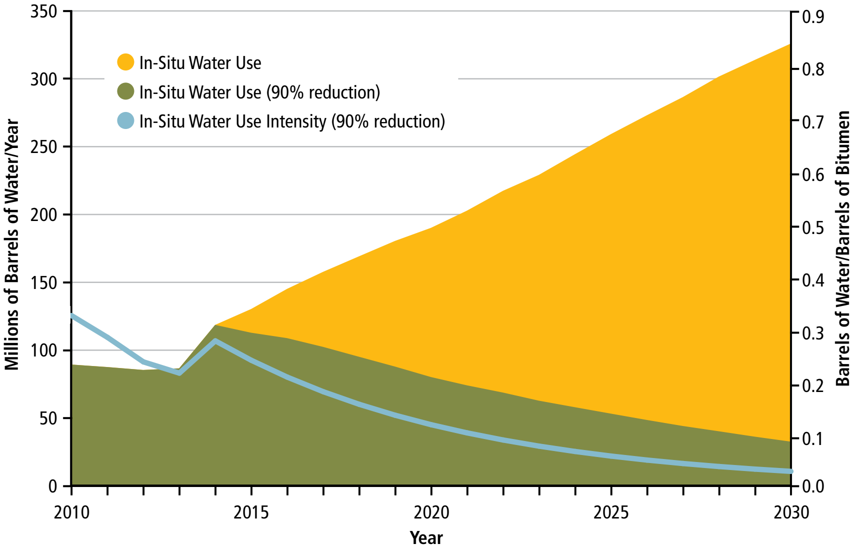


Data Sources: Calculations use data from AER (2014e) and CAPP (2014a)

Figure 7.4

Projected Future Withdrawals of Fresh Water for Mining

The figure shows the potential reductions in freshwater withdrawals for mining assuming that a 50% reduction in water use per barrel of bitumen can be achieved by 2030 (green). The yellow area corresponds to projected water use based on current technologies and the light blue line plots the water use intensity associated with a 50% reduction in aggregate water use.



Data Sources: Calculations use data from AER (2014e) and CAPP (2014a)

Figure 7.5

Projected Future Withdrawals of Fresh Water for In Situ Production

The figure shows the potential reductions in freshwater withdrawals for in situ production assuming that a 90% reduction in water use per barrel of bitumen can be achieved by 2030 (green area). Note that COSIA's in situ performance goal is to reduce water use intensity by 50% by 2022 (COSIA 2014). The yellow area corresponds to projected water use based on current technologies and the light blue line plots the water use intensity associated with a 90% reduction in aggregate water use.

Figures 7.4 and 7.5 highlight potential reductions in water use from mining and in situ production, respectively. The first shows aggregate freshwater withdrawals through to 2030 if 50% reductions are achieved and the second shows aggregate freshwater withdrawals by 2030 if 90% reductions are achieved.

Adoption of Water Technologies: Impediments and Supporting Factors

The adoption of solvent-based extraction technologies, both in mining and in situ operations, faces three main impediments. First, the low price of natural gas makes hot water and steam processes more economical than their alternatives. Second, the relatively low recovery rates of solvents, especially in solvent-based processes, increase the cost of solvent extraction. Third, heterogeneous reservoir quality affects the applicability of solvent extraction across various oil sands operations. Chapters 3 and 4 also note significant technical challenges and performance questions.

Water treatment technologies are subject to some of the same impediments as tailings technologies. Among them are requirements under Alberta's *Environmental Protection and Enhancement Act* that prevent the release of oil sands process-affected water, forcing operators to hold such water on site (Giesy *et al.*, 2010; Alberta Government, 2014b). Furthermore, the water treatment technologies described in Chapter 3 are still in the lab and pilot stages of development, with no clear leading technological solution. Greater clarity about future water treatment guidelines and discharge standards will provide incentives for investment in and adoption of water treatment technologies. Further R&D can help improve solvent recovery, thereby lowering the cost of solvent-based technologies, and provide the means to scale up laboratory- and pilot-based water treatment technologies (Akram, 2008).

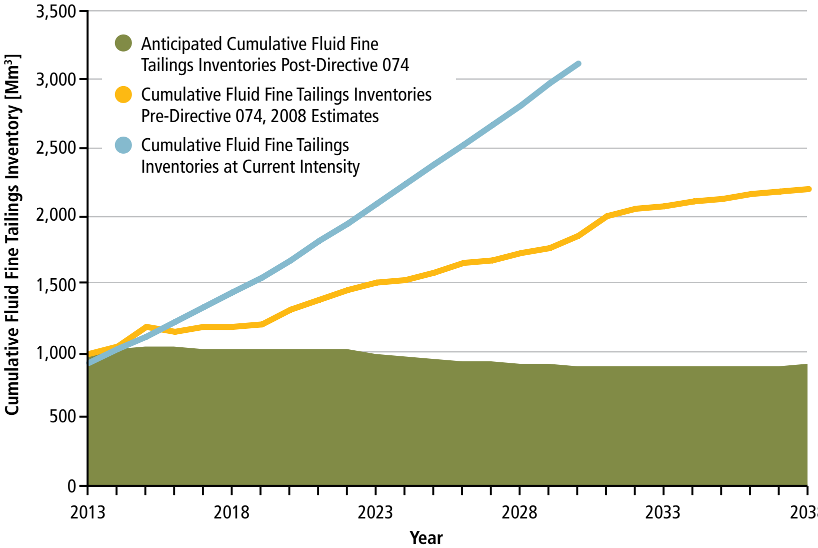
In the Panel's view, the water balance discussion in general only focuses on river impacts of withdrawal, an artefact of the longstanding zero water discharge policy for the oil sands industry. Eventually, consideration of the volumes and flows of treated process-affected water back to the environment will need to be considered in the on-site and off-site water balance discussion. Such a discussion becomes germane especially as tailings technologies seek to dewater fluid fine tailings to ultimately reduce the size of tailings ponds and speed reclamation.

7.2.4 Reducing the Volume and Improving the Composition of Tailings

From a regional perspective, the most pressing component of the environmental footprint is the volume of tailings ponds. This is a growing concern as the size of tailings ponds is increasing with increasing production, with more fluid fine tailings as a result of lower ore quality. As highlighted in Chapter 3, several technologies have already been implemented (e.g., composite tailings, TLD, centrifugation) and others are being tested to reduce the volume of fluid fine tailings and increase the amount of dewatering.

Operators are piloting a range of technologies to reduce the volume of and remediate tailings. While no single "silver bullet" technology currently exists, multiple technologies — if used together and tailored for particular geological and geotechnical conditions and tailings streams — may constitute a "silver suite" of tailings management solutions that could provide the path to acceptable and timely reclamation. Investments in these technologies would reduce the amount of fluid fine tailings rejected per barrel of bitumen so that the growth in tailings volumes would be lower than the mining production growth rate.

In line with the now suspended Directive 074, mining operators have submitted forecasts of the expected trajectory of fluid fine tailings volumes as part of their tailings management plans. The forecasts include the adoption of new technologies. Figure 7.6 compares these forecasts with fluid fine tailings forecasts published in 2008 prior to Directive 074. The difference between the two represents the range of possible trajectories of fluid fine tailings volumes until 2040. Under ideal circumstances, fluid fine tailings volumes could stabilize at a level slightly higher than today, followed by a gradual decrease; however, the delay in Directive 074 implementation shows that the commercial-scale deployment of new technologies is subject to uncertainty and risks of delay or even technology failure. The implication of delays in implementation is that the peak of fluid fine tailings volumes would occur at a higher level and at a later point in time, although it could eventually decrease close to the levels forecast by operators. Technology failure could imply that fluid fine tailings do not stabilize and continue to increase (see Chapter 2).



Data Sources: Calculations use data from AER (2013a) and Houlihan (2008); bitumen production data from CAPP (2014a)

Figure 7.6

Potential Reductions in the Volume of Tailings

The figure shows the potential reductions in the volume of tailings according to the forecasts provided by operators. The green area represents the expected cumulative volume of tailings produced by seven operators between 2013 and 2040 (CNRL horizon, Imperial Oil, Kearl, Suncor, Shell Muskeg River, Shell Jackpine, Syncrude Mildred Lake, and Syncrude Aurora North). This is contrasted against the cumulative volume of tailings at current intensity (light blue line), and the pre-AER Directive 074 2008 estimates (yellow line) from Houlihan and Mian (2008).

Adoption of Tailings Technologies: Impediments and Supporting Factors

The Panel considers the lack of water treatment guidelines and discharge standards that define permissible levels of various contaminants an impediment to the development of tailings technologies. Having these standards in place would expand the range of tailings management options available to operators.

Another impediment stems from the practice used by most oil sands operators to mix coarse and fluid fine tailings (from primary and secondary extraction) with froth treatment tailings (from the froth cleaning step) in tailings ponds. Combining all tailings together worsens the composition of tailings ponds, rendering tailings treatment technologies less effective and reclamation more challenging.

Also, with increased expansion of oil sands production to reserves of lower quality, the recovery rate of bitumen extraction is expected to decline, resulting in greater bitumen losses to tailings ponds. When coupled with the technical challenges associated with compacting and consolidating fluid fine tailings through dewatering, the applicability of the various tailings technologies is further limited.

The Panel believes that there are two avenues to deal with the impediments discussed. First, greater clarity around the future implementation and water treatment guidelines and discharge standards and enforcement of tailings regulations would provide oil sands operators a greater incentive to invest in tailings technologies. Second, keeping separate the more toxic froth treatment tailings from the other more voluminous tailings streams would enable operators to apply different suites of tailings technologies to treating each stream, thereby helping to reduce fugitive emissions from tailings ponds, and facilitate their reclamation. In addition, while the technical challenges associated with dewatering fluid fine tailings and froth treatment tailings are significant, as in the past, further R&D is likely to lead to their improvement.

7.2.5 Reducing Land Impacts

As noted in Chapter 2, surface mining and in situ production have significant impacts on land, a very visible component of the oil sands environmental footprint. Surface mining requires large mine sites, overburden storage, access roads, pipelines, tailings ponds, and end-pit lakes. In fact, the size of a mine site (i.e., the mine sprawl) is often 2.5 times larger than the area of the ore body. In situ sites feature seismic lines, access roads, pipelines, overhead power lines, and well pads. Both processes lead to land fragmentation that extends well beyond the directly impacted area. Oil sands operators are required to reclaim the land, returning it to a state equivalent to pre-disturbance. For surface mine reclamation, the growing volume and composition of tailings are making this an increasingly difficult undertaking.

As noted in Chapter 3, there is no single technology for reducing future land use and reclaiming land already in use. In general, reclamation requires multiple solutions. The greatest contributor to reclamation success after surface mining can be achieved by reducing tailings ponds (Section 7.2.4). The most promising approaches to reduce land impacts of surface mining are tailings and management strategies; the single greatest factor is use of new tailings technologies that target making mine reclamation easier, cheaper, and faster. Management strategies can be grounded into three broad approaches that reduce mine sprawl, increase the rate of reclamation, and increase the quality of reclamation.

Adoption of Land Technologies: Impediments and Supporting Factors

Among the main impediments to reducing land impacts are inadequate knowledge for creating wildlife habitat and the growing volume and composition of tailings ponds, which, as noted, increase surface mine sprawl and slow reclamation efforts. Land use and fragmentation issues are also complex challenges.

Nonetheless, a number of approaches exist to reducing the land impacts from oil sands production. Regional and site-specific monitoring of reclamation efforts, including data management and quality assurance/control, could bring the needed transparency and attention to the issue. Standards for new mines and the enforcement and development of regulations that require more progressive reclamation and more closures of active tailings ponds, could encourage the integrated planning of both surface and in situ mines. Research in ecology and landscape could help speed and improve reclamation efforts. By applying wildlife and landscape ecology principles to mine reclamation, for example, operators could move beyond the current approach, of "build it and they will come," to one that results in wildlife habitat and other end land use goals (Fisher *et al.*, 2014). This could be supported by consultation that allows operators and stakeholders to agree on what constitutes an equivalent landscape and ecosystem for reclamation.

7.3 TOWARDS REDUCING THE ABSOLUTE FOOTPRINT OF OIL SANDS PRODUCTION

Based on the analysis above, the Panel found that although the technologies available on the short- to midterm horizon could reduce the environmental footprint on an intensity basis, they would not bring about absolute reductions at projected production growth rates. This is especially true for GHGs and tailings. As a result, the absolute footprint of the oil sands is likely to continue to increase for three principal reasons.

First, by its nature, oil sands production is both energy and resource intensive: a typical surface mine processes 2.4 barrels of fresh water per barrel of oil and disturbs 9.5 ha of land per million barrels of production; for its part, an average in situ operation generates 82 kg of CO_2e per barrel of production (Grant *et al.*, 2013). By definition, energy and resource intensity results in a heavy environmental footprint. Second, the increase in overall production in recent years has overwhelmed improvements in intensity. Although the production of GHGs per barrel has declined by 26% since 1990 (Oil Sands Today, 2014), total emissions reached 76 Mt CO_2e per year in 2013 (see Figure 2.5). Notwithstanding high levels of recycling, net water consumption could more than double with forecasted oil production increases. Third, there are no proven environmental mitigation technologies for some environmental impacts, such as the destruction of wetlands that provide habitat for migratory birds and some at-risk species (AER, 2013e), other than reduction in sprawl.

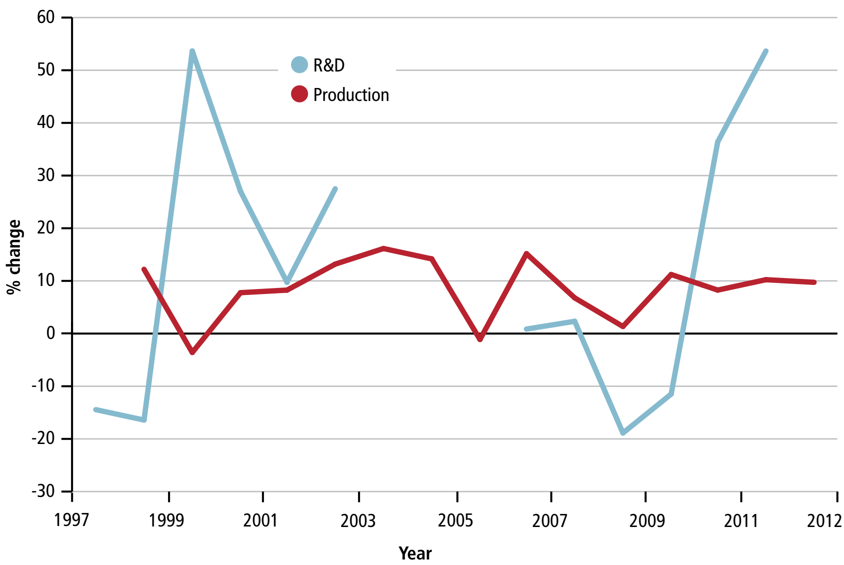
In keeping with these trends, the oil sands industry has been the subject of vigorous international and domestic criticism for its environmental performance. Public concern about the rapid development of the oil sands has intensified in recent years and manifests itself in public opposition to the construction of new pipelines (e.g., Northern Gateway, Keystone XL, Energy East, Kinder Morgan); divestment campaigns by "green" investors; carbon disclosure campaigns (Ellsworth & Snow, 2014); and public demonstrations in Canada and internationally. Restoring public confidence and support for oil sands development requires constant improvement in environmental performance both in communities directly affected by oil sands development and on global issues. Additional individual and collective efforts are also needed to engage local communities, maintain communication channels, and enable information flow (Cleland, 2014).

The next three sections highlight how industry, government, and collaborative initiatives can accelerate the adoption of technologies to reduce the absolute environmental footprint of the oil sands.

7.3.1 Industry Initiatives

The adoption of technologies can be accelerated by at least three industry initiatives. First, the oil sands industry can continue to invest in R&D and technological innovation as it has in the past. Figure 7.7 shows the growth in oil sands production and in total R&D spending, which includes all R&D and not just environmental technology R&D, in 1997–2012. Over this period, the compound annual growth in total R&D spending outstripped the growth in production: 13.4% versus 7.8%. In 2012, for instance, oil sands operators spent $886 million in R&D, up from $478 million in 2009 (Statistics Canada, 2014). Spending in 2012 was 1.29% of oil sands GDP, a significantly greater share than the Canadian oil and gas extraction industry as a whole (0.72%) but broadly similar to chemical manufacturing (1.13%) (CCA, 2013b).

While indicative, these metrics have several limitations. As noted, the R&D spending figures do not separate environmental R&D from R&D that is intended to increase production or reduce costs. In some cases these may coincide (e.g., R&D to reduce SORs), but it is not possible to gain an accurate picture of R&D investment in environmental technology, per se. Moreover, R&D spending generally does not include many incremental process innovations and commercialization activities of oil sands operators (CCA, 2013b). For instance, Box 7.3 highlights how process innovation around slurry hydrotransport led to its widespread adoption and a 40% reduction in GHG emissions from bitumen extraction in surface mining.



Data Sources: Statistics Canada (2014); CAPP (2014a)

Figure 7.7

Growth in Oil Sands Production and Total R&D Spending

The figure plots the growth in oil sands production (red line) and the growth in total R&D spending (blue line) from 1997–2012. Over this period, the compound annual growth of total R&D spending and production was 13.4 and 7.8%, respectively. These figures are subject to several caveats. First, total R&D spending includes all R&D, not just environmental technology R&D. Second, R&D spending pre-2009 is proxied by total oil and gas R&D spending in Alberta since Statistics Canada has only collected oil sands R&D spending data since 2009. Third, data are missing for 2004 and 2005.

Box 7.3
Rapid Adoption of a New Technology: Slurry Hydrotransport

The use of slurry hydrotransport pipelines for bitumen conditioning has been an important technological innovation in the oil sands industry and one that diffused quickly across operators. Compared with the initial Clark Hot Water Extraction Process that required slurry temperatures of 80°C, hydrotransport has been largely responsible for reducing the operating temperature to 40 to 55°C (RSC, 2010; IHS Energy, 2011). As RSC (2010) notes, slurry hydrotransport "represents one of the most innovative and important success stories of technology development in the oil sands industry."

The earlier conditioning technology consisted of mixing the oil sand with hot water and steam in large tumblers (conditioning drums) to create thick slurry. The tumblers introduced air into the slurry and screened it to remove rocks and undigested oil sands lumps. Hydrotransport replaced tumblers by mixing the slurry during transportation. Specifically, slurry hydrotransport is a method of conveying the ore and transporting it by pipeline to the primary separation vessel rather than moving it by conveyor belt. By using a pipeline, the bitumen-sand slurry is mixed while transported, allowing the bonds between the bitumen and the sand to start to break down prior to extraction. Commercialized in 1996 and in use in all oil sands surface mining operations, hydrotransport has reduced the energy intensity of bitumen extraction by approximately 40% (IHS Energy, 2011).

Second, the Panel recognizes that the industry has recently taken an important step towards accelerating technology adoption through the establishment of Canada's Oil Sands Innovation Alliance (COSIA), which brings together 13 oil sands producers "focused on accelerating the pace of improvement in environmental performance in Canada's oil sands through collaborative action and innovation" (COSIA, 2014a). As an industry consortium, COSIA helps disseminate information on a new technology, including its benefits, costs, and associated risks. This has been shown to be an important factor influencing technology adoption (Hall, 2004). COSIA allows oil sands firms to share large capital investment, exchange intellectual property, and set collective emissions reduction goals. Since its launch, firms have shared 560 distinct environmental technologies that cost over $900 million to develop, and created global precedent-setting legal agreements (COSIA, 2014a). Because COSIA was only established in 2012, it is still too early to evaluate its impact. In agreement with its member firms, COSIA focuses only on "end of pipe" technologies rather than changes in production processes. COSIA, for example, does not share information on solvent-assisted technologies for in situ production. The Panel considers the lack of collaboration on solvent-related bitumen recovery and other process technology a potential missed opportunity in the COSIA model.

Third, several oil sands operators have established quantitative targets to drive environmental improvement. Suncor, for example, intends to achieve a 10% absolute reduction in air emissions from 2007 to 2015 (Suncor Energy Inc., 2013b). Statoil has announced its goal of reducing the GHG intensity of its production by 25% and its water intensity by 45% by 2020 (Statoil Canada, 2013). Several producers (e.g., Cenovus, Nexen, Shell, Statoil, Suncor) are using a shadow price for carbon ranging from $15 to $68 per tonne in their internal financial analysis of investment decisions. This price allows them to manage the risk of higher costs of possible future limits on carbon emissions and to identify opportunities in carbon abatement or energy efficiency technologies (Sustainable Prosperity, 2013). Such management commitments, supported by adequate resources and public reporting, can be powerful drivers in fostering improvements in environmental performance.

7.3.2 Government Initiatives

The academic literature is clear that market forces alone typically provide insufficient incentives for the adoption of technologies, leading firms to underinvest relative to what is optimal from a societal perspective (Jaffe *et al.*, 2005). Public policy, it follows, is generally required to provide the necessary impetus for the adoption of environmental technologies (Jaffe *et al.*, 2005; Popp *et al.*, 2010). As noted earlier, governments can support technology adoption with regulations and taxation, on the one hand, and investment, on the other. As highlighted in Section 7.2, among the most significant impediments to the adoption of the most promising technologies are the low value placed on carbon and the lack of water treatment guidelines and discharge standards. Placing a greater value on carbon and providing greater clarity around future water discharge regulations would provide strong incentives for oil sands firms to invest in these technologies.

The Panel also notes that the government can help support a “design-for-closure” approach to oil sands mining sites, which is similar to the practices in other mining operations. This can include incentives that drive the further development of technology and management solutions to discharge water, consolidate tailings, transform tailings pond into non-retaining structures, and earmark funds for future cleanup and reclamation. These incentives would be complementary to the current regulation that specifies the need to reclaim to equivalent land capacity and the previously noted need for water treatment and discharge standards.

As noted above, the $1 billion in reclamation security bonds is inadequate given the nature of firm investment strategy (i.e., net present value) and the lifetime of many mining companies. However, the challenges of closure leading to certification (i.e., custodial transfer of disturbed land back to the Crown) (An *et al.*, 2013; McGreevy *et al.*, 2013) have led some to argue for perpetual care and maintenance as a more practical set of regulations (Cowan Minerals Ltd., 2010; Morgenstern, 2012).

7.3.3 Collaborative Initiatives

Enabling the mass adoption of the most promising technologies requires a healthy and dynamic innovation ecosystem that fosters information exchange, productive collaborations, and R&D. Innovation is the product of the activities of a wide set of actors engaged in generating new knowledge; facilitating linkages between universities, public research organizations, governments, angel and venture capitalists, and firms; developing policies and regulations; and creating and fostering demand for new technologies and processes (CCA, 2013a). To a large extent, Alberta has many of these elements in place. Many actors, from universities and public research organizations to governments and the general public, play important roles in fostering technology development/adoption and innovation.

In the Panel's view, however, more needs to be done if technology is to reduce the absolute environmental footprint. In particular, renewed emphasis is required on fundamental scientific research and knowledge transfer and on collaboration between academia, industry, and government, where research is multidisciplinary and partnerships are fully transparent. Box 7.4 provides an example of the critical role of collaborative research, involving government, academia, and industry, in developing horizontal drilling for SAGD that was conducted through the Alberta Oil Sands Technology and Research Authority (AOSTRA). Currently, for instance, there is an opportunity for big demonstration projects on use of solvents that are focused on solvent content in the rejected waste solids for the case of mining operations, and on solvent impacts on groundwater for in situ operations. Also important is well-timed industry investment (in addition to investment magnitude) such that technologies are developed in the appropriate sequence to create a technology platform. The Panel also stresses the need for regulations to accelerate innovation based on environmental performance, closure, and reclamation rather than on technology mandates, and for involving stakeholders in determining environmental priorities (i.e., global and regional footprint scales).

Box 7.4
Alberta Oil Sands Technology and Research Authority

Founded in 1974 with an initial endowment of $100 million, AOSTRA was an Alberta Crown Corporation with a mandate to "promote the development and use of new technology for oil sands and heavy oil production, with emphasis on reduced costs, increased recovery, and environmental acceptability" (AI-EES, 2014). The technology that resulted from AOSTRA projects, where the costs were shared with industry, were available at fair market value to any user. Projects were selected by a government-appointed board with experience in petroleum development and technology management. AOSTRA also supported research at Canadian universities and research institutions and the operation of a technical information system, ultimately promoting international cooperation in oil sands development (AI-EES, 2014).

Undoubtedly the biggest success of AOSTRA was the development of horizontal well drilling for SAGD. In April 1978, Imperial Oil Limited drilled Canada's first horizontal well into the Clearwater Formation at Cold Lake in an early test of SAGD technique pioneered by Roger Butler. Yet, due to technical challenges and high capital costs, this approach languished for nearly a decade. However, things changed with a series of breakthroughs in the fundamental science of the oil sands, which had largely been ignored up to that point by the academic sector (Campbell, 2013), and the opening in 1987 of Underground Test Facility (UTF), both funded by AOSTRA.

The joint government-industry research program was designed to evaluate horizontal well recovery processes for SAGD. This consisted of drilling a pair of wells into limestone 15 m below the reservoir and injecting steam from above. The pilot project demonstrated recovery rates of 65%, which were significantly higher than initial 30 to 45% estimates, effectively proving Butler's initial concept (McKenzie-Brown, 2012). The UTF tests transformed the oil sands industry, with SAGD and CSS now responsible for a little more than half of production. In 2000, AOSTRA was reorganized into Alberta Energy Research Institute, which today is Alberta Innovates — Energy and Environment Solutions. AI-EES's role now includes other energy-related research areas such as wind, solar, fuel cells, clean coal, and biomass.

The AOSTRA model demonstrates the importance of collaboration among academia, government, and industry in addressing complex challenges. This kind of directed, collaborative R&D may be critical for addressing the central challenge of the oil sands today, namely, reducing its aggregate environmental footprint.

While some technologies will come from the lab, many of the new breakthroughs will come from multidisciplinary, multiparty collaborations working in the field at the pilot and semi-commercial scales. The COSIA Water Technology Development Centre is a promising example of this approach. Along these lines, and in keeping with the major opportunities indicated in this report, the Panel believes that there are opportunities in other areas as well. For example, there is an opportunity to establish a collaborative reclamation research field station that includes unfettered access to the many existing (and some new) instrumented watersheds for reclamation research (McKenna *et al.*, 2011). Such a project, which could engage government, Aboriginal peoples, and NGOs, would help create better reclaimed wildlife habitat and riparian zones in preparation for the formation of hundreds of kilometres of creeks and rivers in the reclaimed oil sands landscapes.

Another opportunity for collaboration is in establishing a tailings field research station, similar to that of the COSIA Water Technology Development Centre, which builds on the success of the Oil Sands Tailings Research Facility in Devon run by the University of Alberta and NRCan's CanmetENERGY Lab. Having the site attached to a commercial operation would allow large-scale pilot testing of technologies with enhanced infrastructure for receiving and disposing of larger volumes of tailings. There is also the prospect of establishing an in situ experimental station for use of solvents and their impact on groundwater and atmospheric emissions, building on the success of the Underground Test Facility (see Box 7.4), and a centre of excellence for development of regional monitoring for reclaimed landscapes.

Finally, there is the specific need for better collaboration between industry, government, First Nations, and other stakeholders to help continuously ensure that the steps taken and avenues explored are the ones jointly agreed upon, ultimately leading to improved outcomes.

7.4 CONCLUSIONS

The central environmental challenge facing oil sands operators is to reduce the absolute footprint of production. However, no suite of technologies available on the short- to medium-term horizon will achieve this reduction at current production growth rates. The adoption of technologies to reduce the footprint requires overcoming several resource input, business, and policy impediments. Options include increasing industry investment in innovation, government support of the oil sands innovation ecosystem, enforcement of effective tailings regulations, developing water treatment and discharge standards, and placing a higher value on carbon. While this role implies an upfront cost for government, it will be justified if the resulting innovations lead to increased resource recovery (increasing royalties and economic growth) and protect the environment (maintaining environmental quality and reducing future liabilities).

Given that most of the growth in bitumen production will come from in situ extraction, this area needs to be prioritized for adopting the latest technologies when launching new projects. On the two most pressing issues, GHG emissions and tailings, a number of technologies are available, or under development, that could reduce the absolute environmental footprint. For instance, combining alternative energy sources and energy efficiency improvements with the adoption of solvent technologies for in situ production, CCS for upgrading, and mobile mining technologies in surface mining has the potential to reduce absolute GHG emissions and, in many cases, reduce air emissions as well. Similarly, treating process-affected water, separating froth treatment tailings, using a suite of tailings technologies, and adopting a design-for-closure approach would reduce the volume of tailings ponds and speed reclamation.

8

Conclusions

8 Conclusions

This chapter answers the main questions and three sub-questions that comprise the charge to the Panel, drawing on the evidence and analysis presented in the preceding chapters. It concludes with the Panel's final reflections on reducing the environmental footprint of oil sands operations.

8.1 RESPONDING TO THE MAIN CHARGE

How could new and existing technologies be used to reduce the environmental footprint of oil sands development on air, water and land?

If widely deployed, many of the technologies now being researched, developed, and piloted for deployment over the next 15 years could reduce the environmental footprint of oil sands operations on an intensity (per barrel) basis. Technologies have been identified in all five areas of the environmental footprint, including several that currently exist and are deployable in the short term. One of these "quick wins" is the use of existing dust suppression technology in mining operations. Dust, which is an important vector for the local and regional distribution of pollutants such as mercury and PAHs, can be readily suppressed, thereby keeping naturally occurring and man-made pollutants largely contained to the mine site. Also, the industry's continued effort to improve efficiencies, which add up over time, will be important in the long run in all areas: retrofitting and replacing haul trucks in surface mining; ongoing improvements in steaming, well placement, and well control for in situ production; and improving operational efficiencies in bitumen upgrading.

Yet for all that these technologies result in measurable improvements in performance on a per barrel basis, none are likely to bring about absolute reductions in the environmental footprint of oil sands operations. The Panel believes that reductions are especially needed for processes that result in discharges directly correlated with bitumen production (which is forecasted to double), namely GHGs and tailings. Indeed, significantly reducing GHG emissions from the oil sands would make them comparable to other sources of crude, and reduce other air pollutants associated with GHG emissions (e.g., NO_x, VOCs). Achieving a reduction in the volume and composition of oil sands tailings, which are more a local and regional problem, is necessary to improve future reclamation and minimize groundwater contamination from seepage.

To reduce GHGs, R&D must focus on in situ technologies because much of the forecasted bitumen production growth — and GHG emissions — will come from accessing reserves via in situ methods. The most promising in situ technologies in the midterm are solvent assisted, which decrease the need for steam in the extraction process and reduce related air emissions and contaminants from burning natural gas. However, even if fully adopted, these technologies would still result in a GHG footprint in 2025 that is higher than today's baseline. More transformative technologies are therefore needed. Based on current knowledge and widespread future adoption, the Panel believes that solvent-based technologies that eliminate the need for steam, and the use of low carbon energy sources, will be important technology pathways for significantly lowering GHG emissions beyond 2025. The commercialization of solvent-based technologies, however, will be affected by uncertainty about cost, solvent recovery, and potential risks of groundwater contamination, which may vary depending on the type of solvent used.

For tailings produced in surface mining extraction, the Panel found that no single technology in development could readily solve all problems with remediating fluid fine tailings and process-affected water. While some of the more promising technologies have been shown to concentrate fluid fine tailings upwards of 65% (solid content), this level is not necessarily sufficient for land reclamation. Operators are, however, piloting a range of technologies to reduce the volume of tailings, increase their density and strength, and improve remediation. If used together and tailored for particular geological and geotechnical conditions and tailings streams, these technologies could constitute a "silver suite" of tailings management solutions that could provide the path to acceptable and timely reclamation.

There is an opportunity to treat the relatively low-volume froth tailings streams to remove the residual solvents. Such treatment, along with more thoughtful disposal practices, would reduce the environmental footprint of this stream.

In the absence of proven technologies, the industry is planning to use end-pit lakes as permanent solutions in the final closure of operations. Given known risks and lack of knowledge about their long-term viability, the Panel believes that much more research is needed before end-pit lakes become an acceptable long-term solution to tailings pond management.

The treatment of process-affected water, which is piped to tailings ponds along with fluid fine tailings, is hindered not so much by a lack of technology but by the lack of water discharge standards and commensurate technology.

For technology in general to have maximum effect in reducing the environmental footprint, three supports are important. First, a well-functioning innovation ecosystem must be in place to foster inter-firm collaboration, knowledge flow between universities and industry practices, and openness to collaborative problem-solving on the environmental footprint. Industry and government have made big strides in this respect, having helped establish a strong research capacity through investments in oil sands-related research institutes and NSERC industrial research chairs. They have also established COSIA, an industry consortium, and CCEMC, which supports the development and application of emission reduction technologies and initiatives that help adapt to climate change. The Panel believes, however, that this effort needs to be strengthened with an even greater emphasis on knowledge sharing and collaboration between industry and researchers that focuses on innovation related to environmental performance, closure, and reclamation.

Second, oil sands regulation should support, rather than impede, technology adoption across the industry. Environmental regulations that prevent the release of oil sands process-affected water make the accumulation in tailings ponds on site a necessity and discourage firms from investing in water treatment technologies that can clean water to quality standards suitable for its release. Regulations that encourage a low carbon price can further discourage innovation in technologies to reduce carbon emissions. It is also important for regulations to incorporate environmental objectives that reflect the full extent of the environmental footprint of oil sands operations. While these now exist for tailings under the Alberta Government's Tailings Management Framework, they do not exist for seepage from tailings ponds, GHG emissions, air emissions, or reclamation rates, for example.

Third, monitoring needs to correspond to any comprehensive environmental objectives established for oil sands development. To this end, the Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring (JOSM) and the establishment of the Alberta Environmental Monitoring, Evaluation and Reporting Agency in April 2014 and its effective functioning will be important, helping identify which environmental effects require attention and assess whether technologies are having their intended impact.[37] There is a further opportunity for joint monitoring of oil sands reclamation (including uplands, wetlands, rivers, and end-pit lakes) to foster efficiency, learning, and innovation. There is an important role for First Nations in such monitoring, as well.

37 JOSM is now monitoring all potentially important substances, excluding GHGs, resulting from oil sands activities, with measurement under way for water, air, health, and biodiversity. See www.jointoilsandsmonitoring.ca.

8.2 RESPONDING TO THE SUB-QUESTIONS

Using the latest deployed technologies and processes as a baseline, what are the potential environmental footprints of new oil sands projects, both mining and in situ?

Oil sands extraction and processing contribute to the environmental footprint through GHG emissions, releasing of air pollutants, water use and creation of tailings, and land disturbances. GHG emissions can be expected to double by 2025 from 2013 levels of 76 Mt, and to keep growing further to approximately 182 Mt by 2030. The growth will be driven primarily by expanded in situ production, whose share in emissions is expected to grow from less than one-half of total emissions in 2013 (47.7%) to more than two-thirds in 2030 (68%).

For air, existing data suggest that current emissions lead to relatively few off-site, ground-level exceedances of objectives and standards set by Alberta and the Canadian Council of Ministers of the Environment. Exceedances that do occur are for odour-related total reduced sulphur compounds and for $PM_{2.5}$, the latter influenced by forest fires and biomass combustion from land clearing. Emissions of SO_2 are likely to remain more or less stable. However, NO_x air emissions are predicted to increase substantially, depending upon the pace of new mine and in situ development. This will result in greater potential for short-term positive, and longer-term negative, consequences to ecosystem productivity. Through the Lower Athabasca Regional Plan, there are now triggers in legislation that could be used to begin to address cumulative effects, at least for SO_2 and NO_2. For mercury emissions from the oil sands industry, ambient air measurements and emission source characterization indicate that they are relatively low. PAH emissions, though largely influenced intermittently by forest fire activity, have been linked, along with trace elements, to surface mining activity some 35 km from mine edges. Finally, although peak concentrations have declined since 2009, industrial odour, likely from fugitive and fixed sources, remains a concern in several communities.

While current water withdrawal rates are within environmental limits, future limits are uncertain. Climate change is expected to affect river flow rates, and growth of in situ production will require access to more waterways and groundwater sources.

Even with complete adoption of the most promising technologies for tailings management and reduction, tailings volumes, and therefore the size of tailings ponds, are not expected to decline. Indeed, tailings remain a significant remediation challenge. Closure planning suggests that the large quantities of fluid fine tailings will be reclaimed by either water capping in end-pit lakes or reprocessed progressively to allow terrestrial reclamation.

Using publicly available information, what extraction, processing and mitigation technologies are currently being researched, developed and demonstrated by the public and private sectors, and how could they reduce or further mitigate the environmental footprint of development on a project or per-barrel basis?

Surface Mining

In surface mining, solvent-based extraction technologies are promising for the elimination or reduction of freshwater withdrawals, to reduce or eliminate fluid fine tailings, and to speed mine reclamation. These technologies, however, are still at an early stage of development, with little to no information available on performance in large-scale operations, cost, or losses of solvents. They also raise their own environmental concerns including evaporation of solvents and their contamination of groundwater when placed in the mine pit.

With the remediation of fluid fine tailings remaining a significant technical challenge despite major investments, no single technology has been identified that can significantly reduce the volume of tailings and significantly increase consolidation of the fluid fine tailings. It is unclear if the suite of technologies now in development — even if used together and tailored for particular geological conditions and tailings streams — provides the path to acceptable land reclamation.

Alongside technology investments, operators can adopt complementary management practices to help speed up reclamation. An early win would be the full integration of mine operation, tailings disposal, reclamation, and closure planning to develop and use a single, dynamic mining plan for each organization that fully embraces the design-for-closure approach. This could reduce mine sprawl and lead to less expensive and more robust closure scenarios. More aggressive and progressive reclamation, whereby ecosystems are reclaimed in areas no longer necessary for mine operations, could also speed up reclamation. Another early win here would be closing tailings ponds when they reach capacity rather than keeping them open in case of future need. There is also an opportunity for greater operator collaboration in mine waste management and reclamation, including sharing of tailings disposal areas, fluid fine tailings feedstocks, reclamation stockpiles, and more seamless designs across lease boundaries.

In Situ Production

For in situ production, improvements in environmental performance are likely to be incremental rather than transformative, with no breakthrough technology expected in the near to midterm that could significantly reduce GHG emissions — the main contribution of in situ processes to the environmental footprint. Most promising among the new technologies are solvent-assisted technologies that add solvents to the steam used in SAGD operations, thereby lowering energy and water requirements. Evidence suggests that these may be able to increase production efficiency by 10 to 30%. There are a number of process innovations now being experimented with, which, together with digital technologies that improve reserve characterization, can further improve efficiencies.

In the longer term, solvent-based technologies that do away with the need to produce steam have the greatest potential to reduce GHGs. Their commercialization will be affected, however, by uncertainty about cost, solvent recovery, and potential risks of groundwater contamination, which may vary depending on the type of solvent used.

Upgrading

While research is under way on several new upgrading technologies, most remain at an early stage of development and are not expected to reduce GHG emissions substantially. The possible exception is sodium metal desulphurization; this, however, consumes large amounts of electricity. Partial upgrading technologies now being developed share the advantage of greatly reducing or eliminating the need for diluent in bitumen transport.

Cross-Process Technologies

Alternative low carbon energy sources have the most potential to significantly reduce GHG emissions at current production growth rates. Low carbon electricity could open up new opportunities for in situ electrification technologies. Barriers, however, must be overcome for each low carbon source, making this a longer-term solution for oil sands development. Indeed, adoption of alternative energy sources in general depends heavily on their economic attractiveness, which, in turn, depends on the price of natural gas, GHG regulations, and the likelihood for capital cost overruns.

GHG emissions can also be reduced by CCS, a proven technology but one that is expensive and currently uneconomic in the absence of further government incentives or the imposition of a higher carbon price. In emitting concentrated point source emissions of CO_2, upgrading is most amenable to current carbon capture technology. Practical considerations in retrofitting upgraders for CCS likely limit carbon capture to 20 to 40% of the carbon stream. As carbon prices rise, however, other energy options (e.g., efficiency, alternative technologies) are likely to become competitive before CCS can be applied to all major sources of GHG emissions from the oil sands.

What are the impediments (i.e., economic, regulatory, etc.) to the deployment, on an accelerated basis, of the most promising technologies?

Impediments to the widespread and rapid deployment of technologies relate to the resources used, business decisions, and government policies. For resources, an important impediment stems from the variability in the quality of the reserve whereby technologies that are effective in extracting ore rich in bitumen may be less effective and efficient for lower-quality ore. As oil sands development proceeds and pushes operators to lower-quality reserves, technologies whose performance depends on ore quality may result in higher environmental footprints as efficiencies decrease. Another resource impediment is the relatively low price of natural gas, one of the most important inputs in oil sands operations. Low prices, for example, discourage investments in solvent-assisted in situ recovery, the use of alternative sources of power, and improvements in energy efficiency, all of which would reduce GHG emissions.

On the business side, technology adoption can be impeded by the scale and life cycle of oil sands projects, which encourage risk aversion and a preference for proven technologies rather than new ones. In the face of uncertainty about technology performance, firms tend to delay investment decisions until more information is made available. Together with high capital costs, there is the risk of technology lock-in as firms invest in proven technologies for the duration of the project.

The rate of technology development on average in the oil and gas sector is also an impediment. Some of the technologies now being tested will fail or not prove commercial; most will take several years to move from concept to market. The lead time for technology development in extractive industries is often 10 to 20 years. Collectively, these business factors have important implications for the many new projects approved or in application stage, for which technology decisions are now being made or will be made in the near future.

Finally, existing regulations, or gaps in regulation, can also impede the rapid adoption of new technologies. As noted, the current carbon (compliance) price is an inadequate economic incentive for firms to invest widely in new technologies to reduce GHG emissions. The reverse of this has been seen in tailings management where regulations have set strict requirements for fluid fine tailings reductions. The effect has been positive for inducing significant industry attention and investment in fluid fine tailings-related R&D. However, by preventing the release of treated water, the regulatory regime prevents operators from releasing oil sands process-affected water, and discourages operators from investing in water treatment technology.

8.3 FINAL CONSIDERATIONS

Technology has always been fundamental to the success of oil sands operations and will only become more so in efforts to reduce the environmental footprint. For new and emerging technology to have the desired environmental impact, however, the pace of innovation needs to correspond to the pace of oil sands development. To this end, the Panel believes that governments and firms across the entire industry need to take on a stronger leadership role in accelerating the pace of technological development and reducing the environmental footprint of oil sands operations. History has shown that oil sands stakeholders have been successful in the past at instigating major change. This occurred in 1974 when the Alberta government established AOSTRA, which kick-started university research into the oil sands, fostered productive collaborations between industry, universities, and government, and whose underground test facility made SAGD a commercial reality. It occurred again in 1996 with the signing of the Declaration of Opportunity, which involved the Prime Minister of Canada, the Government of Alberta, and the presidents of 18 Canadian oil companies coming together to commit to tripling production from 1996 levels by 2020. This goal was achieved in the mid- to late-2000s, over a decade earlier than planned.

Such change is required once more, but this time with a focus on significantly reducing the environmental footprint. There is an opportunity, for example, for a big demonstration project on use of solvents and their impact on groundwater and atmospheric emissions for in situ production, and on solvent content in the rejected waste solids for mining operations. And, while the Panel acknowledges that much has and is being done to address environmental issues, more progress is needed if technology is to catch up to the magnitude of the environmental challenges. At the current pace of oil sands development, the most promising technologies need to be ready for broad adoption in the near term lest existing and less efficient technologies be locked into the majority of new projects. Short of slowing oil sands development, the most promising way forward is an AOSTRA-like approach that pools R&D resources and embraces collaboration and knowledge sharing across all stakeholders towards innovation focused on environmental performance, closure, and remediation.

Appendices

Appendix A – Methods and Assumptions for Environmental Footprint Measurements

This Appendix documents the assumptions and methods used in Chapter 2 for estimating the contribution of oil sands operations to the environmental footprint.

Bitumen Production Forecasts

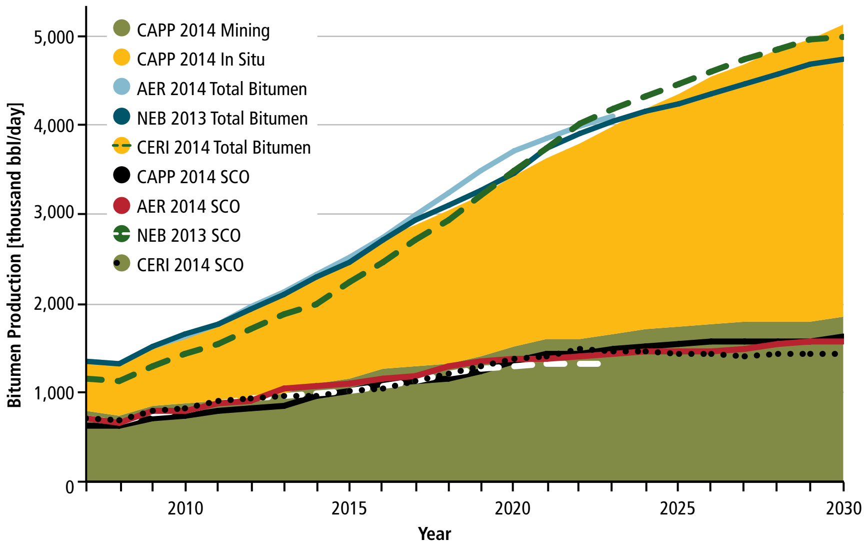
Several of the forecasted emissions presented in this report are based on forecasted estimates of bitumen production from the Canadian Association of Petroleum Producers (CAPP) 2014 forecast, which the Panel deemed to be a reasonable projection of the oil sands industry growth and adequate for the purposes of this assessment.

For comparison, Figure A.1 plots the CAPP forecast alongside those developed by three other Canadian institutions: the Alberta Energy Regulator (AER), the Canadian Energy Research Institute (CERI), and the National Energy Bureau (NEB). All four institutions predict that raw bitumen production will approximately double between 2013 (2 million barrels per day (MMbbl/day)) and 2025 (approximately 4 MMbbl/day) and continue growing, reaching about 5 MMbbl/day in 2030. The share of in situ extraction will increase from approximately 50% in 2013 to 65 to 70% by 2025. The forecasts differ with regard to the share of bitumen that will be upgraded to synthetic crude oil (SCO) in Canada. The difference in upgrading between the forecasts has significant implications for expected future environmental impacts, in particular with regard to GHG emissions and air emissions. CAPP further predicts growing shares of bitumen shipped by rail rather than pipelines, which requires less diluent.[38] Other reports take a contrasting stance, assuming increasing demand for light crude oil by refineries and increasing shipments via pipelines.

Where possible, these estimates are based on current impact intensities, that is the amount of impact created per barrel of bitumen or SCO produced (also referred to as emissions factors).[39] Intensity metrics can be developed in different ways.

38 Based on an analysis of supply contracts and recent infrastructure investments, CAPP (2014) estimates that rail shipments could increase from 300,000 b/day in 2014 to 700,000 b/day in 2016.

39 It is recognized that there is both historic downward pressure on intensities (through technology development, efficiencies, and industry efforts) as well as upward pressures (many of the future mines and SAGD facilities will be harder to develop and operate than previous ones — the easier ore bodies are already being exploited).



Data Sources: Calculations use data from AER (2014e), CAPP (2014a), CERI (2014), and NEB (2013)

Figure A.1

Oil Sands Production and Projection — Comparison of Four Base-Case Scenarios

This figure compares the forecasts of the Canadian Association of Petroleum Producers (CAPP) with those issued by the Alberta Energy Regulator (AER), the Canadian Energy Research Institute (CERI), and the National Energy Board (NEB). The CAPP forecasts for synthetic crude oil (SCO) assumes that all bitumen extracted through surface mining is (and will continue to be) upgraded. The CAPP, CERI, and NEB forecasts expect that raw bitumen production will approximately double by 2025 (from close to 2 MMbbl/day in 2013 to around 4 MMbbl/day in 2025) and reach about 5 MMbbl/day by 2030 (AER forecasts only to 2023). In situ production will also be the dominant production method, accounting for 64% of production by 2030. All production forecasts are based on assumptions about future conditions, which are highly uncertain, including the market price of crude oil, input prices such as natural gas or diluent, transport and storage capacity, or policies. Forecasts also differ in their assumptions about possible substitution effects when relative prices change. The effect of higher prices for natural gas, for example, depends on a forecast's assumption with regard to the use of coke as an alternative fuel for steam generation.

Estimating the future environmental impact based on oil sands production forecasts to 2030 is difficult because forecasts beyond 10 years are highly uncertain, as many of the framing conditions affecting oil sands development, such as oil prices, global oil supplies, and policies, are likely to change in ways that cannot be predicted at this point. Some impacts, such as tailings and land disturbances, are cumulative and will unfold over much longer timeframes up to a century or more. Technologies that reduce the increase in cumulative effects are therefore relevant beyond the timescale considered in this report, but they may not provide solutions to ultimately resolve the legacy problems arising from cumulative impacts.

Environmental Intensity Measures

An intensity measure describes the average environmental footprint that is created per barrel of output produced; for example, greenhouse gas emission factors provide an estimate of the amount of greenhouse gases emitted on average for each barrel of bitumen or SCO produced. Intensity metrics reflect the current technologies used and the level of effort needed to extract a barrel of bitumen under average reservoir conditions. A reduction in intensity implies that the growth of the contribution to the environmental footprint will occur at a lower rate than the overall increase of production (decoupling). The reduction in intensity through technology can however be offset through a decline in average reservoir quality. For example, steam-to-oil ratios (SOR) in SAGD projects increase if the reservoir is heterogeneous, leading to higher GHG emissions and water use.

In surface mining, the thickness of the overburden determines the volume of material overlying the bitumen layer that has to be removed and placed elsewhere for producing a certain volume of bitumen. The ore's composition influences the quantity and quality of tailings produced. Some reports assume that overall reservoir quality of future mining and SADG projects will be lower than that of the first generation projects (IHS Energy, 2011). On the other hand, intensities typically decrease over the lifetime of a project as operators learn to fine tune existing technologies to the conditions of the reservoir, in particular if these improvements respond to economic or policy incentives such as raising input prices or setting a carbon price. Estimating these incremental improvements or the effect of reservoir quality is outside of the scope of this report.

GHG Emissions

In using public data sources when calculating GHG emissions from oil sands operations, several GHG sources are excluded. These are outlined in Table A.1.

Table A.1

Boundaries of Emissions Assessment

Included	Excluded
• All emissions related to extraction process • Emissions related to the production of inputs used (fuel gas, hydrogen, diluent, electricity) • Emissions from flaring • Fugitive emissions • Emission related to transport (electricity for pipeline transport)	• Downstream emissions from refining up to final combustion • Emissions from the use of pet coke (assumed to be stockpiled) • Emissions/emission credits related to cogeneration • Emissions from land use change (land clearance, ecosystem degradation)

Charpentier *et al.* (2011)

Table A.2 shows ranges of emission intensities for mining, in situ extraction, and upgrading. For comparison, the table includes ranges for direct emissions (emissions released on site during the operation phase), total emissions including indirect emissions (emissions associated with the production of inputs for the operation such as natural gas, electricity, and diluent), and total emissions when cogeneration of electricity is used.

Table A.2

Emission Factors for Surface Mining, In Situ Extraction and Upgrading

		Emissions/Energy Content gCO_2e/MJ (HHV)			Emissions/Volume $kgCO_2e/bbl$[ii]		
		Low	Midpoint[i]	High	Low	Midpoint	High
Mining	Direct Emissions	1.60	3.75	5.90	11.01	25.81	40.62
	Total Emissions	2.90	5.90	8.90	19.96	40.62	61.27
	Total with Cogeneration	2.50	5.30	8.10	17.21	36.48	55.76
In Situ	Direct Emissions	7.90	9.90	11.90	54.38	68.15	81.92
	Total Emissions	9.50	12.80	16.10	65.40	88.11	110.83
	Total with Cogeneration	9.00	11.40	13.80	61.96	78.48	95.00
Upgrading	Direct Emissions	4.50	7.40	10.30	28.47	46.82	65.17
	Total Emissions	7.10	11.9	16.70	49.35	77.51	105.67
	Total with Cogeneration	6.40	10.95	15.50	46.82	72.45	98.08

Data Sources: Bergerson *et al.* (2012) and Charpentier *et al.* (2011)

[i] Not a weighted average.

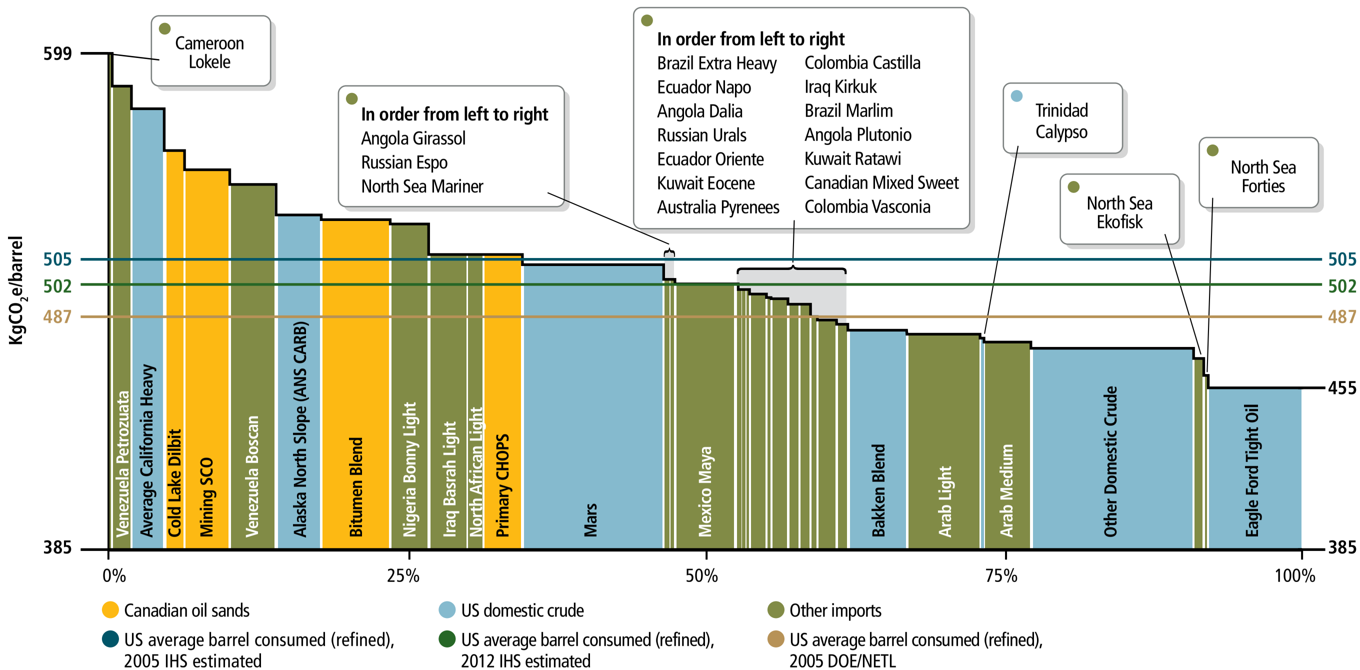
[ii] Calculated based on the higher heating values of bitumen (43.3 GJ/m^3) and synthetic crude oil (39.8 GJ/m^3).

Life Cycle GHG Emissions of Conventional and Non-Conventional Sources of Crude Oil Compared

Emissions of the production of hydrocarbons represent only a small share of their total life cycle emissions, which include all emissions along the production processing and consumption pathway up to their final combustion or use. LCA methodologies have gained increasing importance with the introduction of low carbon fuel standards in California and the EU, which aim at reducing the average carbon intensity of transportation fuels used on a life cycle basis. LCA methods to compare the life cycle GHG emissions of different fuels comprise four to five stages: crude oil extraction, transportation to a refinery, refining (transport of liquid fuel product), and final combustion. For gasoline produced from oil sands bitumen, the GHG emissions associated with extraction, upgrading, and transport on average account for 30% of the total life cycle emissions. However, as can be seen from Box 2.1, there is great variance in emission factors between projects. This means that some projects have life cycle emissions that are comparable to conventional oil extraction, while some other projects have life cycle emissions comparable to some of the heaviest oil reservoirs in the world (Venezuela and California; see Figure A.2).

Sprawl Factor for Land Impacts

The sprawl factor can be calculated from observed intensity measures that express the amount of land disturbed per unit of output produced (e.g., m^2/m^3 SCO). The average ore quality in oil sands surface mining suggests that a sprawling factor of 1 (i.e., only disturb land over the ore body) corresponds to an intensity of $0.33 m^2/m^3$ SCO. Jordaan *et al.* (2009) use a LCA approach to develop intensity metrics for land footprint that takes fragmentation into account by including additional buffer zones that are affected by the polygonal and linear features created. These values can be used to develop a general estimate of the direct land disturbance caused by oil sands activities. The lower bound of Jordaan *et al.*'s (2009) land use intensity factor was estimated by dividing the project area by the area of initial established reserves, where $0.42\ m^2/m^3$ equals a sprawl factor of 1.27 (i.e., is the feasible minimum disturbance necessary to be able to mine). Calculations are based on new disturbed area/year — based either on total disturbed area reported between 1987-2008 (ESRD, 2014c) and 2009-2013 (ESRD, 2014d) — divided by total production of SCO (ESRD, 2014b). These calculations provide an average factor of land use intensity of $1.04\ m^2/m^3$ SCO or a sprawl factor of 3.15, which is 2.48 times higher than the minimum sprawl factor of 1.27.



Reproduced with permission from IHS Energy, Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil (2014)

Figure A.2

Well to Wheel GHG Emissions: Oil Sands Compared to Other Crude Oils

This figure compares the life cycle emissions of fuels produced in the United States from domestic and imported sources. The GHG intensity of fuel produced from oil sands bitumen ranges from slightly above the average of all fuels refined in the United States for bitumen produced through cold heavy oil production with sand (CHOPS – not considered in this report) to fuels with significantly higher intensities derived from mined SCO and bitumen extracted in situ.

Appendix B – Glossary of Key Terms

Asphaltenes: Large hydrocarbon molecules found in low percentages within light crude oil but larger percentages within heavier crude oils and even higher proportions in bitumen. Asphaltenes have a very high viscosity and low hydrogen to carbon ratio. Asphaltenes are soluble in aromatic solvents but not soluble in straight-chain solvents like pentane or heptane.

Bitumen: A thick, sticky form of crude oil that is so heavy and viscous that it will not flow unless it is heated or diluted with lighter hydrocarbons. At room temperature, bitumen looks much like cold molasses. It typically contains more sulphur, metals, and heavy hydrocarbons than conventional crude oil.

Carbon Capture and Storage (CCS): The removal of CO_2 from effluent streams in industrial processes and the subsequent injection of the CO_2 into underground chambers.

Coke: High carbon material that is a by-product of coking, the process of applying high temperature and pressure to crude oil to produce coke and light liquid hydrocarbons.

Composite Tailings (CT): Fine tailings combined with gypsum and sand. Composite tailings settle more rapidly than standard tailings, resulting in faster reclamation times.

Cyclic Steam Stimulation (CSS): An in situ method of bitumen recovery that uses steam injection to reduce the viscosity of bitumen deposits, making it possible to pump bitumen to the surface. The process occurs in cycles, with steam injection followed by a resting period, followed by a production phase, then another steam injection and so on.

Dilbit: Bitumen diluted with a diluent.

Diluent: A hydrocarbon substance used to dilute crude bitumen so that it can be transported by pipeline.

End-Pit Lake: An engineered mine pit filled with mature fine tailings that have naturally densified to over 30% solids content, then capped with water to form a lake. Once acceptable surface water quality is attained, in-flow to and out-flow from surrounding terrain is established to emulate a natural lake system.

Enhanced Oil Recovery (EOR): The third stage of hydrocarbon production during which sophisticated techniques that alter the original properties of the oil are used. Enhanced oil recovery can begin after a secondary recovery process or at any time during the productive life of an oil reservoir. Its purpose is not only to restore formation pressure, but also to improve oil displacement or fluid flow in the reservoir.

The three major types of enhanced oil recovery operations are chemical flooding (alkaline flooding or micellar-polymer flooding), miscible displacement (CO_2 injection or hydrocarbon injection), and thermal recovery (steam flood). The optimal application of each type depends on reservoir temperature, pressure, depth, net pay, permeability, residual oil and water saturations, porosity and fluid properties such as oil API gravity, and viscosity.

Environmental Footprint: For the purposes of this report, the environmental footprint is defined as the contribution from emissions, energy use, water use, and land use that represent the effect of oil sands development on the environment.

The scope of the report limits the environmental footprint analysis to that associated with only the bitumen recovery stage of oil production. It does not, for example, take into full account the cumulative impacts of these emissions on animal health or biodiversity.

Fine Tailings: Water with very small particles of suspended clay produced by the mining extraction process.

Froth Treatment: The means to recover bitumen from the mixture of water, bitumen, and solids "froth" produced in hot water extraction (in mining-based recovery).

Hydrocracking: Refining process for reducing heavy hydrocarbons into lighter fractions, using hydrogen and a catalyst; can also be used in upgrading of bitumen.

Hydrotransport: Mixing mined oil sand with hot water and caustic for transport by pipeline from mine site to the extraction facility.

In Situ: Latin for "in place." In oil sands recovery, all non-mining methods employed to collect bitumen deposits are in situ.

In Situ Combustion: A displacement enhanced oil recovery method. It works by generating combustion gases (primarily CO and CO_2) downhole, which then "pushes" the oil towards the recovery well.

Mature Fine Tailings (MFT): Fine tailings that have separated into a sediment layer of clay and silt and an upper layer of clarified water.

Naphtha: The portion of a crude barrel with a boiling point between 145°F and 400°F. Naphtha can be used as diluent.

Oil Sands: Sand, clay, or other minerals saturated with bitumen. Defined in the Alberta Mines and Minerals Act as "(i) sands and other rock materials containing crude bitumen, (ii) the crude bitumen contained in those sands and other rock materials, and (iii) any other mineral substance (except natural gas) associated with the above-mentioned crude bitumen, sands or rock materials and includes a hydrocarbon substance declared to be oil sands under section 7(2) of the *Oil Sands Conservation Act*."

Overburden: The layer of soil, rocks, and organic material on top of a deposit of oil sand.

Particulate Matter (PM): Small particles that become airborne from open sources. Particulate matter can be separated into three categories: total particulate matter (TPM) includes all particles with aerodynamic diameter less than ~100 μm; coarse particulate matter (PM_{10}) includes particles smaller than 10 μm but larger than 2.5 μm; and fine particulate matter includes particles smaller than 2.5 μm.

Polycyclic Aromatic Hydrocarbons (PAHs): A class of chemicals that occur naturally in coal, crude oil, and gasoline as well as many organic materials. They are released when coal, oil, gas, wood, garbage, and tobacco are burned.

Process-Affected Water: All waters that have come in contact with mining or tailings areas.

Steam-Assisted Gravity Drainage (SAGD): An in situ method of bitumen recovery using horizontal wells and steam stimulation.

Steam-to-Oil Ratio (SOR): Relating to in situ oil production, indicating the proportion of steam required to produce a barrel of oil. An SOR of 3, for example, means that three barrels of water, vaporized into steam, are required to produce one barrel of bitumen. Cumulative SOR (CSOR) denotes the average amount of steam required over the lifetime of a project, taking into account the steam required for initial reservoir conditioning. Instantaneous SOR (ISOR) is the amount of steam required per barrel at a specific point in time.

Surface Mining: Method of extracting bitumen ore with shovel excavators and very large haul trucks. Surface mining is limited to the North Athabasca region of the oil sands where the bitumen ore lies within about 75 m of the surface.

Synbit: A blend of cleaned crude bitumen mixed with SCO for diluent in order to meet pipeline viscosity and density specifications.

Synthetic Crude Oil (SCO): Similar to crude oil, created by upgrading bitumen from oil sands.

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

Thermal Recovery: Any process by which heat energy is used to reduce the viscosity of bitumen in situ to facilitate recovery.

Upgrading: The process by which heavy oil and bitumen are converted into lighter crude by increasing the ratio of hydrogen to carbon, normally using either coking or hydroprocessing.

Volatile Organic Compound (VOC): Volatile organic compounds are a class of organic carbon-containing compounds that evaporate under normal indoor atmospheric conditions of temperature and pressure.

Sources: OSTC and COSIA (2012); Alberta Government (2015); Oilsands Review (2015)

References

References

Abusaid, A., Pollock, G. W., Fear, C., McRoberts, E., & Wells, S. (2011). *An Update to the Construction of the Suncor Oil Sands Tailings Pond 5 Cover.* Paper presented at Tailings and Mine Waste, Vancouver (BC).

AER (Alberta Energy Regulator). (2009). *Directive 074: Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes.* Edmonton (AB): AER.

AER (Alberta Energy Regulator). (2013a). Tailings Plans 2011 and 2012. Retrieved February. 2015, from http://www.aer.ca/rules-and-regulations/directives/tailings-plans-2012.

AER (Alberta Energy Regulator). (2013b). *2012 Tailings Management Assessment Report: Oil Sands Mining Industry.* Calgary (AB): AER.

AER (Alberta Energy Regulator). (2013c). *Directive 082: Operating Criteria: Resource Recovery Requirements for Oil Sands Mine and Processing Plant Operations.* Calgary (AB): AER.

AER (Alberta Energy Regulator). (2013d). Application 1752450. Retrieved April 2014, from http://www.aer.ca/applications-and-notices/notices/application-1752450#.

AER (Alberta Energy Regulator). (2013e). *Report of the Joint Review Panel Established by the Federal Minister of the Environment and the Energy Resources Conservation Board.* Calgary (AB): Canadian Environmental Assessment Agency and the Energy Resources Conservation Board.

AER (Alberta Energy Regulator). (2013f). ST98-2013_CrudeBitumen. Retrieved January 2015, from http://www.aer.ca/documents/sts/ST98/ST98-2013_CrudeBitumen.xls.

AER (Alberta Energy Regulator). (2014a). *Oil Sands Information Portal. Total Oil Sands Production Graph.* Edmonton (AB): AER.

AER (Alberta Energy Regulator). (2014b). *Oil Sands Information Portal. Oil Sands Operators: Water Use History.* Edmonton (AB): AER.

AER (Alberta Energy Regulator). (2014c). *Alberta Mineable Oil Sands Plant Statistics.* Calgary (AB): AER.

AER (Alberta Energy Regulator). (2014d). *Oil Sands Information Portal. Historical Oil Sands Mine Land Disturbance and Reclamation Tracking, 1987-2008.* Edmonton (AB): AER.

AER (Alberta Energy Regulator). (2014e). *ST98-2014. Alberta's Energy Reserves 2013 and Supply/Demand Outlook 2014/2023.* Vol. ST98-2013. Edmonton (AB): AER.

AER (Alberta Energy Regulator). (2014f). *Oil Sands Information Portal. Regional Totals for Reclamation and Disturbance Tracking, by Year.* Edmonton (AB): AER.

AER (Alberta Energy Regulator). (2014g). Oil Sands. Retrieved April 2014, from http://www.aer.ca/about-aer/spotlight-on/oil-sands#.

AER (Alberta Energy Regulator). (2015). Supply and Disposition of Sulphur. Retrieved February 2015, from http://www.aer.ca/documents/sts/st3/Sulphur_current.xls.

Ahad, J., Gammon, P., Gobeil, C., Jautzy, J., Krupa, S., Savard, M., & Studabaker, W. (2014). Evaporative emissions from tailings ponds are not likely an important source of airborne PAHs in the Athabasca oil sands region. *Proceedings of the National Academy of Sciences of the United States of America, 111*(24), E2439.

AI-EES (Alberta Innovates - Energy and Environment Solutions). (2012). *Turning Ideas Into Action: 2011-12 Report on Outcomes.* Edmonton (AB): AI-EES.

AI-EES (Alberta Innovates - Energy and Environment Solutions). (2014). *2014-2017 Business Plan: Alberta Innovates - Energy and Environment Solutions.* Edmonton (AB): AI-EES.

Akram, F. (2008). *Effects of Well Placement and Intelligent Completions on SAGD in a Full-Field Thermal-Numerical Model for Athabasca Oil Sands.* Paper presented at International Thermal Operations and Heavy Oil Symposium, Calgary (AB).

Alberta Energy and Utilities Board. (2004). *Suncor Energy Inc.: Application for an External Tailings Pond for the Millennium Mine Fort McMurray Area.* Edmonton (AB): Alberta Energy and Utilities Board.

Alberta Environment & Fisheries and Oceans Canada. (2007). *Water Management Framework: Instream Flow Needs and Water Management System for the Lower Athabasca River.* Edmonton (AB) and Ottawa (ON): Alberta Environment & Fisheries and Oceans Canada.

Alberta Government. (2008a). *Alberta's 2008 Climate Change Strategy: Responsibility / Leadership / Action.* Edmonton (AB): Environment and Sustainable Resource Development.

Alberta Government. (2008b). *Launching Alberta's Energy Future: Provincial Energy Strategy.* Edmonton (AB): Alberta Energy.

Alberta Government. (2009). *Responsible Actions: A Plan for Alberta's Oil Sands.* Edmonton (AB): Alberta Government.

Alberta Government. (2011). *Facts About Alberta's Oil Sands Tailings Management.* Edmonton (AB): Alberta Government.

Alberta Government. (2012a). *Groundwater Management Framework for the Lower Athabasca Region.* Edmonton (AB): Alberta Government.

Alberta Government. (2012b). *Carbon Capture and Storage Regulatory Framework Assessment.* Edmonton (AB): Alberta Government.

Alberta Government. (2014a). Carbon Capture and Storage. Retrieved April 2014, from http://www.energy.alberta.ca/Initiatives/1438.asp.

Alberta Government. (2014b). Reclamation. Retrieved November 2014, from http://www.oilsands.alberta.ca/reclamation.html.

Alberta Government. (2014c). *Environmental Protection and Enhancement Act.* Edmonton (AB): Alberta Government.

Alberta Government. (2014d). *Alberta Oil Sands Industry: Quarterly Update.* Edmonton (AB): Alberta Government.

Alberta Government. (2014e). Oil Sands Information Portal. Retrieved April 2014, from http://environment.alberta.ca/apps/osip/.

Alberta Government. (2014f). *Technical Guidance for Completing Specified Gas Compliance Reports.* Edmonton (AB): Alberta Environment and Sustainable Resource Development.

Alberta Government. (2014g). Oil Sands: Economic Benefits. Retrieved September 2014, from http://oilsands.alberta.ca/economicinvestment.html.

Alberta Government. (n.d.). Oil Sands Glossary. Retrieved February 2015, from http://www.energy.alberta.ca/OilSands/1708.asp.

Alberta Government (2015a). *Lower Athabasca Region: Tailings Management Framework for the Mineable Athabasca Oil Sands.* Edmonton (AB): Alberta Government.

Alberta Government (2015b). *Lower Athabasca Region: Surface Water Quantity Management Framework for the Lower Athabasca River.* Edmonton (AB): Alberta Government.

Alberta WaterSMART. (2009). *Review of Upgrader Water Treatment Technology.* Calgary (AB): Alberta WaterSMART.

Allen, E. W. (2008a). Process water treatment in Canada's oil sands industry: II. A review of emerging technologies. *Journal of Environmental Engineering and Science, 7*(5), 499-524.

Allen, E. W. (2008b). Process water treatment in Canada's oil sands industry: I. Target pollutants and treatment objectives. *Journal of Environmental Engineering and Science, 7*(2), 123-138.

AMEC. (2013). *Beach Fines Capture Study.* Edmonton (AB): AMEC.

An, R., McKenna, G., Scordo, E., & McGreevy, J. (2013). *Toward Effective Closure Planning. From Progressive Reclamation to Sustainable Mining.* Paper presented at Tailings and Mine Waste 2013 Conference, Banff (AB).

Ardali, M., Barrufet, M., Mamora, D. D., & Qiu, F. (2012). *A Critical Review of Hybrid Steam-Solvent Processes for the Recovery of Heavy Oil and Bitumen.* Paper presented at SPE Annual Technical Conference and Exhibition, San Antonio (TX).

Atkinson, G. M. & Martens, S. N. (2007). Seismic hazard estimates for sites in the stable Canadian craton. *Canadian Journal of Civil Engineering, 34*(10), 1299-1311.

Aubertin, M. & Chapuis, R. P. (1991). *Critères de Conception pour les Ouvrages de Retenue des Résidus Miniers dans la Région de l'Abitibi.* Paper presented at First Canadian Conference on Environmental Geotechnics, Montréal (QC).

Aubertin, M., Dionne, J., & Marcoux, L. (1997). *Design Guidelines and Stability Criteria of Engineering Works for Water Covers.* Paper presented at Fourth International Conference on Acid Rock Drainage, Vancouver (BC).

Aubertin, M., Bussière, B., & Bernier, L. (2002a). *Environnement et Gestion des Rejets Miniers [Manual on CD-ROM].* Montréal (QC): Les Presses Internationales Polytechnique.

Aubertin, M., Mbonimpa, M., Jolette, D., Bussière, B., Chapuis, R. P., James, M., & Riffon, O. (2002b). *Stabilité Géotechnique des Ouvrages de Retenue les Résidus Miniers: Problèmes Persistants et Méthodes de Contrôle.* Paper presented at Symposium 2002 sur l'Environnement et les Mines, Rouyn-Noranda (QC).

Aubertin, M., Bussière, B., James, M., Jaouhar, E. M., Martin, V., Pépin, N., … Chapuis, R. P. (2011). *Vers une Mise à Jour des Critères de Stabilié Géotechnique pour la Conception des Ouvrages de Retenue de Résidus Miniers.* Paper presented at Symposium 2011 sur l'Environnement et les Mines, Rouyn-Noranda (QC).

Azam, S. & Li, Q. (2010). Tailings dam failures: A review of the last one hundred years. *Geotechnical News, December 2010*, 50-53.

Bari, M. & Kindzierski, W. B. (2015). Fifteen-year trends in criteria air pollutants in oil sands communities of Alberta, Canada. *Environmental International, 74*, 200-208.

Beier, N., Alostaz, M., & Sego, D. (2009). *Natural Dewatering Strategies for Oil Sands Fine Tailings.* Paper presented at Tailings and Mine Waste Conference, Banff (AB).

Bergerson, J. A., Kofoworola, O., Charpentier, A. D., Sleep, S., & MacLean, H. L. (2012). Life cycle greenhouse gas emissions of current oil sands technologies: Surface mining and in situ applications. *Environmental Science and Technology, 46*(14), 7865-7874.

Bernanke, B. S. (1983). Irreversibility, uncertainty, and cyclical investment. *The Quarterly Journal of Economics, 98*(1), 85-106.

BGC Engineering Inc. (2010a). *Review of Reclamation Options for Oil Sands Tailings Substrates.* Edmonton (AB): Oil Sands Research and Information Network, University of Alberta.

BGC Engineering Inc. (2010b). *Oil Sands Tailings Technology Review.* Edmonton (AB): Oil Sands Research and Information Network, University of Alberta.

BGC Engineering Inc. (2013). *Mineable Oil Sands Aquifer Management and Reclamation Concept Review: North Athabasca Oil Sands Region Final.* Fort McMurray (AB): CEMA Water Working Group.

Birkham, T. K., Hendry, M. J., Barbour, S. L., & Lawrence, J. R. (2010). Controls and rates of acid production in commercial-scale sulphur blocks. *Journal of Environmental Quality, 39*(3), 834-844.

Blum, J. D., Johnson, M. W., Gleason, J. D., Demers, J. D., Landis, M. S., & Krupa, S. (2012). Mercury Concentration and Isotopic Composition of Epiphytic Tree Lichens in the Athabasca Oil Sands Region. In K. E. Percy (Ed.), *Alberta Oil Sands: Energy, Industry and the Environment*. Oxford, United Kingdom: Elsevier.

Bohm, M. (2012). Oil Sands GHG Mitigation Roadmap Study. Retrieved September 2014, from http://www.ai-ees.ca/media/8544/2012-energytechnologies-mark_bohm-oil_sands_ghg_mitigation.pdf.

Brons, G., Myers, R. D., Bearden, R., & MacLeod, J. B. (2001). Contacting Petroleum Feed with Sodium Metal Using Staged Addition, Heating in Presence of Excess Hydrogen to Suppress Formation of Sodium Sulfide (na2s) and to Form of Sodium Sulfhydrate (Nash) During Desulfurization. *US Patent 6210564*: Google Patents.

Cabrera, C. A., Hillerman, M. D., & Silverman, M. A. (2012). *HTL Heavy Oil Upgrading: Monetizing Stranded Heavy Oil Assets in Remote Locations*. Paper presented at 2012 World Heavy Oil Congress, Aberdeen, Scotland.

Caldwell, J., Revington, A., McPhail, G., & Charlebois, L. (2014). *Optimized Seasonal Deposition for Successful Management of Treated Mature Fine Tailings*. Paper presented at Proceedings of the 17th International Seminar on Paste and Thickened Tailings, Vancouver (BC).

Campbell, D. (2013, November 19). Clement Bowman Remembers the Founding of AOSTRA, *Alberta Oil*.

Canadian Dam Association. (2007). *Application of Dam Safety Guidelines to Mining Dams*. Toronto (ON): Canadian Dam Association.

Canadian Dam Association. (2014). *Application of Dam Safety Guidelines to Mining Dams*. Toronto (ON): Canadian Dam Association.

Canadian Natural Resources Limited. (2012). *2013 Horizon Tailings Management Plan*. Calgary (AB): Energy Resources Conservation Board.

CAPP (Canadian Association of Petroleum Producers). (2013). *Responsible Canadian Energy: 2013 Progress Report Summary*. Calgary (AB): CAPP.

CAPP (Canadian Association of Petroleum Producers). (2014a). *Crude Oil Forecast, Markets and Transportation*. Calgary (AB): CAPP.

CAPP (Canadian Association of Petroleum Producers). (2014b). *The Facts On: Oil Sands*. Calgary (AB): CAPP.

CAPP (Canadian Association of Petroleum Producers). (2014c). A Revolution in Heavy Oil Technology. Retrieved December 2014, from http://www.capp.ca/energySupply/innovationStories/Water/Pages/undergroundCombustion.aspx.

CAPP (Canadian Association of Petroleum Producers). (2014d). Fresh Water Withdrawal: Oil Sands In Situ. Retrieved April 2014, from http://www.capp.ca/rce/oil-sands/water/situ/.

CAPP (Canadian Association of Petroleum Producers). (2014e). In Situ: Fresh Water Withdrawal. Retrieved January 2015, from http://www.capp.ca/rce/regional-performance/oil-sands/water/in-situ/.

CAPP (Canadian Association of Petroleum Producers). (2014f). Long-term Sustainability. Retrieved April 2014, from http://www.capp.ca/energySupply/innovationStories/Air/Pages/long-term-sustainability.aspx.

Castendyk, D. & Eary, L. E. (Eds.). (2009). *Mine Pit Lakes.* Englewood (CO): Society for Mining, Metallurgy & Exploration.

CCA (Council of Canadian Academies). (2013a). *Innovation Impacts: Measurement and Assessment.* Ottawa (ON): The Expert Panel on the Socio-Economic Impacts of Innovation Investments, CCA.

CCA (Council of Canadian Academies). (2013b). *The State of Industrial R&D in Canada.* Ottawa (ON): The Expert Panel on the State of Industrial R&D, CCA.

CCA (Council of Canadian Academies). (2014a). *Energy Prices and Business Decision-Making in Canada: Preparing for the Energy Future.* Ottawa (ON): The Expert Panel on Canadian Industry's Competitiveness in Terms of Energy Use, CCA.

CCA (Council of Canadian Academies). (2014b). *Environmental Impacts of Shale Gas Extraction in Canada.* Ottawa (ON): The Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction, CCA.

CCEMC (Climate Change and Emissions Management Corporation). (2012). Poplar Creek Project, ET-DSP™ for Development of Athabasca Oil Sands. Retrieved April 2014, from http://ccemc.ca/project/poplar-creek-project-et-dsp-for-development-of-athabasca-oil-sands/#.

CCEMC (Climate Change and Emissions Management Corporation). (2013a). *2012/2013 Annual Report: Global Challenges. Local Solutions.* Sherwood Park (AB): CCEMC.

CCEMC (Climate Change and Emissions Management Corporation). (2013b). CCEMC Launches $35 Million Grand Challenge to Find Innovative Carbon Uses. Retrieved January 2015, from http://ccemc.ca/ccemc_news/ccemc-launches-35-million-grand-challenge-to-find-innovative-carbon-uses/.

CCEMC (Climate Change and Emissions Management Corporation). (2014). OTSG Oxy-fuel Demonstration. Retrieved December 2014, from http://ccemc.ca/project/otsg-oxy-fuel-demonstration/.

CDC (Centers for Disease Control and Prevention). (2009). *Polycyclic Aromatic Hydrocarbons (PAHs).* Washington (DC): U.S. Department of Health & Human Services.

CEMA (Cumulative Environmental Management Association). (2012). *End Pit Lake Guidance Document.* Fort McMurray (AB): CEMA.

CEMA (Cumulative Environmental Management Association). (2013). *Annual Report 2012*. Fort McMurray (AB): CEMA.

CEMA (Cumulative Environmental Management Association). (2014). *Guidelines for Wetland Establishment on Reclaimed Oil Sands Leases*. Fort McMurray (AB): CEMA.

Cenovus Energy Inc. (2014a). *Cenovus Foster Creek In-Situ Oilsands Scheme (8623) Update for 2013*. Calgary (AB): Alberta Energy Regulator.

Cenovus Energy Inc. (2014b). Blowdown Boiler. Retrieved April 2014, from http://www.cenovus.com/operations/technology/blowdown-boiler.html.

Cenovus Energy Inc. (2014c). *Cenovus Christina Lake In-Situ Oil Sands Scheme 8591: 2013 Update*. Calgary (AB): Alberta Energy Regulator.

CERI (Canadian Energy Research Institute). (2008). *Green Bitumen: The Role of Nuclear, Gasification, and CCS in Alberta's Oil Sands*. Calgary (AB): CERI.

CERI (Canadian Energy Research Institute). (2014). *Canadian Oil Sands Supply Costs and Development Projects (2014-2048)*. Vol. 133. Calgary (AB): CERI.

CESD (Commissioner of the Environment and Sustainable Development). (2011). *Chapter 2: Assessing Cumulative Environmental Effects of Oil Sands Projects*. Ottawa (ON): Office of the Auditor General.

CESD (Commissioner of the Environment and Sustainable Development). (2014). *2014 Fall Report*. Ottawa (ON): Office of the Auditor General.

CETC (Canmet Energy Technology Centre). (2006). *Canada's CO_2 Capture & Storage Technology Roadmap*. Ottawa (ON): Natural Resources Canada.

Charpentier, A. D., Bergerson, J. A., & MacLean, H. L. (2009). Understanding the Canadian oil sands industry's greenhouse gas emissions. *Environmental Research Letters, 4*(1), 014005.

Charpentier, A. D., Kofoworola, O., Bergerson, J. A., & MacLean, H. L. (2011). Life cycle greenhouse gas emissions of current oil sands technologies: GHOST model development and illustrative application. *Environmental Science and Technology, 45*(21), 9393-9404.

Choquette-Levy, N., MacLean, H. L., & Bergerson, J. A. (2013). Should Alberta upgrade oil sands bitumen? An integrated life cycle framework to evaluate energy systems investment tradeoffs. *Energy Policy, 61*(2013), 78-87.

Clair, T. & Davies, M. (2015). Introduction to the Report: Assessing Forest Health in the Alberta Oil Sands Region. In T. Clair & K. E. Percy (Eds.), *Assessing Forest Health in the Alberta Oil Sands Region*. Fort McMurray (AB): Wood Buffalo Environmental Association.

Cleland, M. (2014). *From the Ground Up: Earning Public Support for Resource Development*. Calgary (AB): Canada West Foundation.

CO_2 Solutions. (2014). CO_2 Solutions Successfully Completes Second Oil Sands Project Milestones. Retrieved April 2014, from http://www.co2solutions.com/uploads/file/a1f87d5b82755c37c9e1358ce46057a3810fc773.pdf.

Collins, P. (2007). *Geomechanical Effects on the SAGD Process.* Paper presented at SPE International Thermal Operations and Heavy Oil Symposium / International Conference on Horizontal Well Technology, Calgary (AB).

Connacher Oil and Gas Limited. (2013). *Connacher AER Performance Review November 2013: Great Divide (10587) 2013 Performance Presentation.* Calgary (AB): Alberta Energy Regulator.

Connacher Oil and Gas Limited. (2014). Connacher's Infrastructure Has Been Built to Accomodate Future Expansion of the Great Divide Region. Retrieved November 2014, from http://www.connacheroil.com/index.php?page=algar.

ConocoPhillips. (2014). *Annual Surmont SAGD Performance Review: Approvals 9426, 11596, and 9460.* Calgary (AB): Alberta Energy Regulator.

Cook, D. (2007). The changing face of oilsands mining: Mobile crushing systems on the way. *Oilsands Review.*

COSIA (Canada's Oil Sands Innovation Alliance). (2015). Tailings Centrifugation. Retrieved March 2014, from http://www.cosia.ca/tailings-centrifugation.

COSIA (Canada's Oil Sands Innovation Alliance). (2014a). Home Page. Retrieved September 2014, from http://www.cosia.ca/.

COSIA (Canada's Oil Sands Innovation Alliance). (2014b). Gas-Turbine Once Through Steam Generator. Retrieved April 2014, from http://www.cosia.ca/initiatives/greenhouse_gases/gas-turbine-once-through-steam-generator.

COSIA (Canada's Oil Sands Innovation Alliance). (2014c). COSIA's Water Performance Goal. Retrieved November 2014, from http://www.cosia.ca/initiatives/water/water-performance-goals.

COSIA (Canada's Oil Sands Innovation Alliance). (2014d). Boiler Blowdown Reduction Technologies. Retrieved April 2014, from http://www.cosia.ca/initiatives/water/boiler-blowdown-reduction-technologies.

COSIA (Canada's Oil Sands Innovation Alliance). (2014a). Vacuum Insulated Tubing. Retrieved April 2014, from http://www.cosia.ca/initiatives/greenhouse_gases/vacuum-insulated-tubing.

COSIA (Canada's Oil Sands Innovation Alliance). (2014e). Waste Heat Recovery. Retrieved April 2014, from http://www.cosia.ca/initiatives/greenhouse_gases/waste-heat-recovery.

Cowan Minerals Ltd. (2010). *Policy Framework in Canada for Mine Closure and Management of Long Term Liabilities.* Ottawa (ON): National Orphaned/Abandoned Mines Initiative (NOAMI).

CTMC (Consortium of Oil Sands Tailings Management Consultants). (2012a). *Oil Sands Tailings Technology Deployment Roadmaps.* Vol. 2. Edmonton (AB): CTMC.

CTMC (Consortium of Oil Sands Tailings Management Consultants). (2012b). *Oil Sands Tailings Technology Deployment Roadmaps.* Vol. 1. Edmonton (AB): CTMC.

Czarnecki, J., Masliyah, J., Zhenghe, X., & Dabros, M. (2011). *Handbook on Theory and Practice of Bitumen Recovery from Athabasca Oil Sands* (Vol. 2). Calgary (AB): Kingsley Publishing Services.

Dawson, R. F., Sego, D. C., & Pollock, G. W. (1999). Freeze-thaw dewatering of oil sands fine tailings. *Canadian Geotechnical Journal, 36*(4), 587-598.

DEEP (Deep Earth Energy Production). (2014). Project Development Strategy. Retrieved September 2014, from http://www.deepcorp.ca/project-development-strategy/.

Department of Finance Canada. (2009). Canada's Economic Action Plan: Budget 2009. Ottawa (ON): Government of Canada.

Devenny, D. W. (2006). *Planning Reclamation of Oil Sands Tailings.* Calgary (AB): The Rock Doctor.

Devenny, D. W. (2010). *A Screening Study of Oil Sand Tailings Technologies and Practices.* Edmonton (AB): Alberta Energy Research Institute.

Dickson, J. L., Dittaro, L. M., & Boone, T. J. (2013). *Integrating the Key Learnings from Laboratory, Simulation, and Field Tests to Assess the Potential for Solvent Assisted - Steam Assisted Gravity Drainage.* Paper presented at SPE Heavy Oil Conference Canada, Calgary (AB).

Dittaro, L. M., Jaafar, A. E., Perlau, D., Boone, T., Yerian, J. A., Dickson, J. L., & Wattenbarger, C. (2013). *Findings from a Solvent-Assisted SAGD Pilot at Cold Lake.* Paper presented at SPE Heavy Oil Conference Canada, Calgary (AB).

Dixit, A. K. & Pindyck, R. S. (1994). *Investment Under Uncertainty.* Princeton (NJ): Princeton University Press.

Dobchuk, B. S., Shurniak, R. E., Barbour, S. L., O'Kane, M. A., & Song, Q. (2013). Long-term monitoring and modelling of a reclaimed watershed cover on oil sands tailings. *International Journal of Mining, Reclamation and Environment, 27*(3), 180-201.

Doran, G. F., Williams, K. L., Drago, J. A., Huang, S. S., & Leong, L. Y. C. (1998). *Pilot-Study Results to Convert Oilfield Produced Water to Drinking-Water or Reuse Quality.* Paper presented at SPE Annual Technical Conference, New Orleans (LA).

Doran, K. N. (2013). *Post-Closure Land-Uses in the Athabasca Oil Sands Area.* Paper presented at 17th International Conference on Tailings and Mine Waste, Banff (AB).

Eaton, B. R. & Fisher, J. T. (2011). *The State of Existing Empirical Data and Scientific Knowledge on Habitat-Species Relationships for Wildlife that Occupy Aquatic Habitats, with a Focus on the Boreal Region of Alberta.* Vegreville (AB): Alberta Innovates – Technology Futures.

Elliott, K. (2008). *Examination of Oil Sands Projects: Gasification, CO2 Emissions and Supply Costs*. Paper presented at 2008 SPE International Thermal Operations and Heavy Oil Symposium, Calgary (AB).

Ellsworth, P. & Snow, K. (2014). *The 21st Century Investor: Ceres Blueprint for Sustainable Investing*. Boston (MA): Ceres.

Enhance Energy. (2014). The Alberta Carbon Trunk Line Project: Fact Sheet. Retrieved April 2014, from http://www.enhanceenergy.com/pdf/ACTL/actl_fact_sheet.pdf.

Environment Canada & Alberta Government. (2012). *Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring*. Ottawa (ON): Government of Canada.

Environment Canada. (2013a). *Canada's Emissions Trends*. Ottawa (ON): Government of Canada.

Environment Canada. (2013b). National Pollutant Release Inventory. Retrieved April 2014, from http://www.ec.gc.ca/inrp-npri/.

Environment Canada. (2014a). Multi-sector air pollutants regulations. *Canada Gazette, 148*(23).

Environment Canada. (2014b). *Canada's Sixth National Report on Climate Change*. Ottawa (ON): Government of Canada.

EPA (U.S. Environmental Protection Agency). (1999). *National Recommended Water Quality Criteria-Correction*. Washington (DC): EPA - Office of Water 4304.

EPA (U.S. Environmental Protection Agency). (2008). *Polycyclic Aromatic Hydrocarbons (PAHs)*. Washington (DC): EPA.

EPA (U.S. Environmental Protection Agency). (2014). Environmental Footprint Analysis. Retrieved February 2015, from http://www.epa.gov/sustainability/analytics/environmental-footprint.htm.

ERCB (Energy Resources Conservation Board). (2009). *Directive 074: Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes*. Calgary (AB): ERCB.

ERCB (Energy Resources Conservation Board). (2011). Regulatory Action in Alberta's Oil Sands. Retrieved January 2015, from https://www.aer.ca/documents/reports/RegulatoryActioninAlbertasOilSands_201104.pdf.

ESRD (Alberta Environment and Sustainable Resource Development). (2012). *Lower Athabasca Region - Groundwater Management Framework*. Calgary (AB): ESRD.

ESRD (Alberta Environment and Sustainable Resource Development). (2013). *Alberta Ambient Air Quality Objectives and Guidelines Summary*. Calgary (AB): ESRD.

ESRD (Alberta Environment and Sustainable Resource Development). (2014a). Oil Sands Mines Reclamation and Disturbance Tracking by Company to the End of the Reporting Year. Retrieved February 2015, from http://osip.alberta.ca/library/Dataset/Details/29.

ESRD (Alberta Environment and Sustainable Resource Development). (2014b). Total Oil Sands Production Graph. Retrieved February 2015, from http://osip.alberta.ca/library/Dataset/Details/46.

ESRD (Alberta Environment and Sustainable Resource Development). (2014c). Historical Oil Sands Mine Land Disturbance and Reclamation Tracking, 1987 - 2008. Retrieved February 2015, from http://osip.alberta.ca/library/Dataset/Details/24.

ESRD (Alberta Environment and Sustainable Resource Development). (2014d). Oil Sands Mine Reclamation and Disturbance Tracking by Year. Retrieved February 2015, from http://osip.alberta.ca/library/Dataset/Details/27.

ESRD (Alberta Environment and Sustainable Resource Development). (2014e). Oil Sands Operators: Water Use History. Retrieved December 2014, from http://osip.alberta.ca/library/Dataset/Details/56.

ETX Systems Inc. (2009). IYQ Upgrading – An Industry Altering Technology for Primary Upgrading of Heavy Oil. Puerto La Cruz, Venezuela: World Heavy Oil Congress.

ETX Systems Inc. (2013). Realizing the Full Potential from Bitumen and Heavier Crudes – IYQ Upgrading. Calgary (AB): ETX Systems Inc.

EUB (Alberta Energy and Utilities Board). (2007). *Decision 2007-058: North West Upgrading Inc, Application to Construct and Operate an Oil Sands Upgrader in Sturgeon County*. Calgary (AB): EUB.

Evans, M. S. & Talbot, A. (2012). Investigations of mercury concentrations in walleye and other fish in the Athabasca River ecosystem with increasing oil sands developments. *Journal of Environmental Monitoring, 14*(7), 1989-2003.

Fair, A. (2013). *Collaboration in Canada's Oil Sands: Fluid Fine Tailings Management.* Paper presented at Third International Oil Sands Tailings Conference, Lake Louise (AB).

Fear, C., McRoberts, E., Nik, R. M., & Esposito, G. (2014). *Conventional Oil Sands Tailings Can Achieve Fines Capture of 60% and Higher.* Paper presented at Fourth International Oil Sands Tailings Conference, Lake Louise (AB).

Fell, R., MacGregor, P., Stapleton, D., & Bell, G. (2005). *Geotechnical Engineering of Dams.* London: Taylor & Francis.

Fenton, M. M., Waters, E. J., Pawley, S. M., Atkinson, M., Utting, D. J., & Mckay, K. (2013). *Surficial Geology of Alberta (Map 601).* Edmonton (AB): Alberta Geological Survey.

Ferguson, G. P., Rudolph, D. L., & F., B. J. (2009). Hydrodynamics of a large oil sand tailings impoundment and related environmental implications. *Canadian Geotechnical Journal, 46*(12), 1446-1460.

Figueroa, J. D., Fout, T., Plasynski, S., McIlvried, H., & Srivastava, R. D. (2008). Advances in CO_2 capture technology—The U.S. Department of Energy's Carbon Sequestration Program. *International Journal of Greenhouse Gas Control, 2*(1), 9-20.

Finan, A. E. & Kadak, A. C. (2010). Integration of nuclear energy into oil sands projects. *Journal of Engineering for Gas Turbines and Power, 132*(4).

Finn, W. D., Konrad, J. M., List, B. R., Lord, E. R., Byrne, P. M., Morgenstern, N. R., … Hughes, J. (2000). The CANLEX project: Summary and conclusions [Canadian Liquefaction Experiment]. *Canadian Geotechnical Journal, 37*(3), 563-591.

Fisher, J. T., McKenna, G. T., & Pollard, J. (2014). *An Ecological Framework for Wildlife Habitat Design for Oil Sands Mine Reclamation.* Fort McMurray (AB): Oil Sands Research and Information Network.

Flach, P. D. (1984). *Oil Sands Geology - Athabasca Deposit North.* Edmonton (AB): Alberta Research Council.

Frank, R., Roy, J., Bickerton, G., Rowland, S., Headley, J., Scarlett, A., … Hewitt, M. (2014). Profiling oil sands mixtures from industrial developments and natural groundwaters for source identification. *Environmental Science & Technology, 48*, 2660-2670.

Freeman, C. & Soete, L. (1997). *The Economics of Industrial Innovation* (3rd ed.). London, United Kingdom: Pinter Press.

Gates, I. D. & Wang, J. (2011). *Evolution of In Situ Oil Sands Recovery Technology: What Happened and What's New?* Paper presented at SPE International Heavy Oil Conference and Exhibition, Kuwait City, Kuwait.

Gates, I. D. & Larter, S. R. (2013). Energy efficiency and emissions intensity of SAGD. *Fuel, 115*, 706-713.

Ghannadi, S., Irani, M., & Chalaturnyk, R. (2014). Evaluation of induced thermal pressurization in clearwater shale caprock in electromagnetic steam-assisted gravity-drainage projects. *SPE Journal, 19*(3).

Giesy, J. P., Anderson, J. C., & Wiseman, S. B. (2010). Alberta oil sands development. *Proceedings of the National Academy of Sciences, 107*(3), 951-952.

Gillingham, K., Newell, R. G., & Palmer, K. (2009). Energy efficiency economics and policy. *Annual Review of Resource Economics, 1*(1), 597-619.

GLENSOL. (2008). Case Study: The Canadian Oil Sands and GLENSOL. Retrieved September 2014, from http://www.glensol.co.za/case-study/.

Global CCS Institute. (2014). The Global Status of CCS: 2014. Retrieved November 2014, from http://www.globalccsinstitute.com/in-focus/global-status-ccs-2014.

Government of Canada. (2013). Canada's Action on Climate Change: The Copenhagen Accord. Retrieved April 2014, from http://www.climatechange.gc.ca/default.asp?lang=En&n=AA3F6868-1.

Government of Canada. (2014). Canada-Alberta Oil Sands: Environmental Monitoring Information Portal. Retrieved September 2014, from http://www.jointoilsandsmonitoring.ca/default.asp?lang=En&n=5F73C7C9-1.

Grant, J., Angen, E., & Dyer, S. (2013). *Forecasting the Impacts of Oilsands Expansion.* Calgary (AB): Pembina Institute.

Gray, M. R. (2002). New technique defines the limits of upgrading heavy oil, bitumens. *Oil and Gas Journal, 100*(1), 50-54.

Gray, M. R. (2010). Upgrading of Oil Sands Bitumen. *Course Notes for CHE 522 Fundamentals of Oil Sands Upgrading.* Edmonton (AB): Department of Chemical and Materials Engineering, University of Alberta.

Gray, M. R. (2015). *Upgrading Oil Sands Bitumen and Heavy Oil.* Edmonton (AB): University of Alberta Press.

Greaves, M., Dong, L. L., & Rigby, S. (2012). Validation of Toe-to-Heel Air-Injection bitumen recovery using 3D combustion-cell results. *SPE Reservoir Evaluation and Engineering, February 2012*, 72-85.

Hall, B. H. (2004). *Innovation and Diffusion.* Cambridge (MA): National Bureau of Economic Research.

Hansen, B. & Davies, S. (1994). Review of potential technologies for the removal of dissolved components from produced water. *Chemical Engineering Research and Design, 72*, 217-227.

Hart, A., Leeke, G., Greaves, M., & Wood, J. (2014). Down-hole heavy crude oil upgrading by CAPRI: Effect of hydrogen and methane gases upon upgrading and coke formation. *Fuel, 119*, 226-235.

Hashemi, R., Nassar, N. N., & Almao-Pereira, P. (2014). Nanoparticle technology for heavy oil in-situ upgrading and recovery enhancement: Opportunities and challenges. *Applied Energy, 133*, 374-387.

Hazewinkel, R. R. O., Wolfe, A. P., Pla, S., Curtis, C., & Hadley, K. (2008). Have atmospheric emissions from the Athabasca Oil Sands impacted lakes in northeastern Alberta, Canada? *Canadian Journal of Fisheries and Aquatic Sciences, 65*(8), 1554-1567.

Head, I. M., Gray, N. D., & Larter, S. R. (2014). Life in the slow lane; biogeochemistry of biodegraded petroleum containing reservoirs and implications for energy recovery and carbon management. *Frontiers in Microbiology, 5*, 566.

Headwaters Inc. (2011). Headwaters Incorporated Announces Successful Commercial Implementation of the HCAT® Heavy Oil Upgrading Technology at the Neste Oil Porvoo Refinery. Retrieved December 2014, from http://www.businesswire.com/news/home/20110118005649/en/Headwaters-Incorporated-Announces-Successful-Commercial-Implementation-HCAT®#.VJMB-AALA.

Holland, A., Wechsler, D., Patel, A., Molloy, B. M., Boyd, A. R., & Jessop, P. G. (2010). Separation of bitumen from oil sands using a switchable hydrophilicity solvent. *Canadian Journal of Chemistry, 90*, 805-810.

Houlihan, R. & Mian, H. (2008). *Oil Sands Tailings: Regulatory Perspective.* Paper presented at International Oil Sands Tailings Conference, Edmonton (AB).

ICO2N (Integrated CO2 Network). (2009). *Carbon Dioxide Capture and Storage: A Canadian Clean Energy Opportunity.* Calgary (AB): ICO2N.

ICO2N (Integrated CO2 Network). (2011). *Perspective on Conducting Cost Analyses of CO_2 Capture Technologies.* Calgary (AB): ICO2N.

IEA & UNIDO (International Energy Agency and United Nations Industrial Development Organization). (2011). *Technology Roadmap: Carbon Capture and Storage in Industrial Applications.* Paris, France and Vienna, Austria: IEA and UNIDO.

IHS Energy. (2011). *Special Report: Oil Sands Technology: Past, Present, and Future.* Cambridge (MA): IHS CERA.

IHS Energy. (2013). *Extracting Economic Value from the Canadian Oil Sands: Upgrading and Refining in Alberta (or not)?* Cambridge (MA): IHS CERA.

IHS Energy. (2014). *Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil.* Englewood (CO): IHS Energy.

IMF (International Monetary Fund). (2014). *Canada: Selected Issues.* Washington (DC): IMF.

Imperial Oil. (2012). *2013 Annual Tailings Plan.* Fort McMurray (AB): Energy Resources Conservation Board.

Imperial Oil. (n.d.). Oil Sands Innovation. Retrieved September 2014, from http://www.imperialoil.ca/Canada-English/operations_sands_innovation.aspx.

Isaacs, E. E. (2012a). *Submission to the Subcommittee on Energy and Power.*

Isaacs, E. E. (2012b). Technology and Innovation in the Oil Sands. *PTAC Oilsands Forum: Increasing Production, Reducing Costs and Improving Market Access.* Calgary (AB): Petroleum Technology Alliance of Canada.

Isaacs, E. E. (2014). GHG Reduction: Carbon Capture and Storage, *Chemical Looping Demonstration Plant.* Edmonton (AB).

Ivanhoe Energy. (2014a). HTL Process. Retrieved April 2014, from http://www.ivanhoeenergy.com/?page=htl_process_overview.

Ivanhoe Energy. (2014b). Ivanhoe Suspends Activity on Tamarack Project Pending Regulatory Clarity. Retrieved April 2014, from http://www.ivanhoeenergy.com/index.php?page=news_releases&op=view&id=206.

Jaccard, M. (2005). *Sustainable Fossil Fuels.* Cambridge, United Kingdom: Cambridge University Press.

Jaffe, A. B., Newell, R. G., & Stavins, R. N. (2005). *A Tale of Two Market Failures: Technology and Environmental Policy.* Amsterdam, Netherlands: Elsevier.

James, M., Aubertin, M., Wijewickreme, D., & Wilson, G. W. (2011). A laboratory investigation of the dynamic properties of tailings. *Canadian Geotechnical Journal, 48*(11), 1587-1600.

James, M., Aubertin, M., & Bussière, B. (2013). *On the Use of Waste Rock Inclusions to Improve the Performance of Tailings Impoundments.* Paper presented at 18th International Conference on Soil Mechanics and Geotechnical Engineering, Paris, France.

Jaremko, D. (2014, December). Thermal Oilsands Projects Steam to Oil Ratios, *Oilsands Review.*

Jordaan, S. M., Keith, D. W., & Stelfox, B. (2009). Quantifying land use of oil sands production: A life cycle perspective. *Environmental Research Letters, 4*(2), 1-15.

Jordaan, S. M. (2012). Land and water impacts of oil sands production in Alberta. *Environmental Science & Technology, 46*(7), 3611-3617.

Jung, K. & Chang, S. X. (2012). Four years of simulated N and S depositions did not cause N saturation in a mixedwood boreal forest ecosystem in the oil sands region in northern Alberta, Canada. *Forest Ecology and Management, 280,* 62-70.

Jung, K., Chang, S. X., Ok, Y. S., & Arshad, M. A. (2013). Critical loads and H+ budgets of forest soils affected by air pollution from oil sands mining in Alberta, Canada. *Atmospheric Environment, 69,* 56-64.

Kapadia, P. R., Kallos, M. S., & I.D., G. (2011). Potential for hydrogen generation from in situ combustion of Athabasca bitumen. *Fuel, 90*(1), 2254-2265.

Kasperski, K. L. (2003). *Review of Research on Aqueous Extraction of Bitumen from Mined Oil Sands (Unpublished Report).* Devon (AB): CANMET Energy Technology Centre, Natural Resources Canada.

Kelly, E. N., Short, J. W., Schindler, D. W., Hodson, P. V., Ma, M., Kwan, A. K., & Fortin, B. L. (2009). Oil sands development contributes polycyclic aromatic compounds to the Athabasca River and its tributaries. *Proceedings of the National Academy of Sciences, 106*(52), 22346-22351.

Kelly, E. N., Schindler, D. W., Hodson, P. V., Short, J. W., Radmanovich, R., & Nielsen, C. C. (2010). Oil sands development contributes elements toxic at low concentrations to the Athabasca River and its tributaries. *Proceedings of the National Academy of Sciences, 107*(37), 16178-16183.

Keohane, N. O. (2009). Cap and trade, rehabilitated: Using tradable permits to control U.S. greenhouse gases. *Review of Environmental Economics and Policy, 3*(1), 42-62.

Kheshgi, H. S., Thomann, H., Bhore, N. A., Hirsch, R., Parker, M. E., & Teletzke, G. F. (2012). Perspectives on CCS cost and economics. *SPE Economics & Management, January 2012*, 24-31.

Kilian, L. (2008). The economic effects of energy price shocks. *Journal of Economic Literature, 46*(4), 871-909.

Kirk, J. L., Muir, D. C. G., Gleason, A., Wang, X., Lawson, G., Frank, R. A., … Wrona, F. (2014). Atmospheric deposition of mercury and methylmercury to landscapes and waterbodies of the Athabasca oil sands region. *Environmental Science & Technology, 48*(13), 7374-7383.

Knight, R. L., Kadlec, R. H., & Ohlendorf, H. M. (1999). The use of treatment wetlands for petroleum industry effluents. *Environmental Science & Technology, 33*, 973-980.

Kobayashi, H. S. & Van Hassel, B. (2005). CO2 Reduction by Oxy-Fuel Combustion: Economics and Opportunities. *GCEP Advance Coal Workshop.* Provo (UT): Praxair, Inc.

Küpper, A. (2013). *Delicensing Oil Sands Tailings Dams – When is a dam no longer a dam?* Paper presented at Tailings and Mine Waste Conference, Banff (AB).

Larter, S., Gates, I. D., Adams, J., Jiang, C., Snowdon, L., Bennett, B., & Huang, H. (2012a). Preconditioning an Oilfield Reservoir (BRUTUS). *U.S. Patent 8, 235,110.*

Larter, S., Head, I., Jones, D., Erdmann, M., & Wilhelms, L. (2012b). Patent Application for Process for Stimulating Production of Hydrogen from Petroleum in Subterranean Formations. Retrieved February 2015, from http://www.google.com/patents/CA2569954C?cl=en.

Lattanzio, K. (2014). *Canadian Oil Sands: Life-Cycle Assessments of Greenhouse Gas Emissions.* Washington (DC): Congressional Research Service.

Leach, A. (2012). Policy forum: Alberta's Specified Gas Emitters Regulation. *Canadian Tax Journal, 60*(4), 881-898.

Li, W., Mamora, D. D., & Li, Y. (2011). Solvent-type and -ratio impacts on solvent-aided SAGD process. *SPE Reservoir Evaluation & Engineering, June 2011*, 320-331.

Lunn, S. (2013). Water use in Canada's oil-sands industry: The facts. *SPE Economics & Management, 5* (January 2013), 17-27.

M.J. Bradley & Associates. (2008). *Evaluation of Vehicle Emissions Reduction Options for the Oil Sands Mining Fleet.* Manchester (NH): M.J. Bradley & Associates.

Macleod, S. (2011, September 1). Oil Sands Operators Turn to Electric Currents, *Alberta Oil.*

Majorowicz, J., Unsworth, M., Chacko, T., Gray, A., Heaman, L., Potter, D. K., … Babadagli, T. (2012). Geothermal Energy as a Source of Heat for Oil Sands Processing in Northern Alberta, Canada. In F. J. Hein, D. Leckie, S. Larter & J. Suter (Eds.), *Heavy-Oil and Oil Sand Petroleum Systems in Alberta and Beyond: AAPG Studies in Geology* (Vol. 64). Tulsa (OK): The American Association of Petroleum Geologists, Canadian Heavy Oil Association and AAPG Energy Minerals Division.

Masliyah, J., Czarnecki, J., & Zhenghe, X. (2011). *Handbook on Theory and Practice of Bitumen Recovery from Athabasca Oil Sands* (Vol. 1). Calgary (AB): Kingsley Publishing.

McCullough, C. D. (Ed.). (2011). *Mine Pit Lakes: Closure and Management.* Perth, Australia: Australian Centre for Geomechanics.

McGee, B. C. W., McDonald, C. W., & Little, L. (2009). Comparative proof of concept results for electrothermal dynamic stripping process: Integrating environmentalism with bitumen production. *SPE Projects, Facilities & Construction, December 2009*, 141-145.

McGreevy, J., McKenna, G., An, R., & Scordo, E. (2013). *Regional Mine Closure Plans – The Next Improvement in Closure Planning.* Paper presented at Tailings and Mine Waste 2013 Conference, Banff (AB).

McKenna, G., O'Kane, M., & Qualizza, C. (2011). *Tools for Bringing Mine Reclamation Research to Commercial Implementation.* Paper presented at Tailings and Mine Waste Conference, Vancouver (BC).

McKenna, G., Dawson, R., Hyndman, P., LeSueur, P., & Sobkowicz, J. (2013). *The Oil Sands Tailings Technology Roadmap and Action Plan: Oil Sands Tailings State of Practice Overview.* Paper presented at Third International Oil Sands Tailings Conference, Lake Louise (AB).

McKenna, G. T. (2002). *Sustainable Mine Reclamation and Landscape Engineering.* Edmonton (AB): University of Alberta.

McKenzie-Brown, P. (2012, June). Where It All Began, *Oilweek.*

McLachlan, S. (2014). *"Water is a Living Thing": Environmental and Human Health Implications of the Athabasca Oil Sands for the Mikisew Cree First Nation and Athabasca Chipewyan First Nation in Northern Alberta. Phase 2 Report.* Winnipeg (MB): University of Manitoba.

McRoberts, E. (2008). *Oil Sands Tailings Retention.* Paper presented at First International Oil Sands Tailings Conference, Edmonton (AB).

MEG Energy Corp. (2014). *Christina Lake Regional Project: 2013/2014 Performance Presentation. Commercial Scheme Approval No. 10773.* Calgary (AB): Alberta Energy Regulator.

Metcalf, G. E. (2009). Designing a carbon tax to reduce U.S. greenhouse gas emissions. *Review of Environmental Economics and Policy, 3*(1), 63-83.

Middleton, R. S. & Brandt, A. R. (2013). Using infrastructure optimization to reduce greenhouse gas emissions from oil sands extraction and processing. *Environmental Science and Technology, 47*(3), 1735-1744.

Mikula, R. (2012). Advances in Oil Sands Tailings Handling: Building the Base for Reclamation. In D. H. Vitt & J. H. Bhatti (Eds.), *Restoration and Reclamation of Boreal Ecosystems: Attaining Sustainable Development.* Cambridge (MA): Cambridge University Press.

Miller, R. & Côté, M. (2012). *Innovation Reinvented: Six Games that Drive Growth.* Toronto (ON): Rotman-UTP Publishing.

Milne, J. (2008). Carbon taxes in the United States: The context for the future. *Vermont Journal of Environmental Law, 10*(1), 1-30.

Moorhouse, J. & Peachey, B. (2007, Jan. 7). Cogeneration and the Alberta Oil Sands - Cogeneration Benefits are Maximized with Extraction and Upgrading Integration, *Cogeneration and On-site Power Production.*

Moran, K., Doiron, J., Hill, A., & Sishtla, C. (2013). Production of heavy minerals concentrate and bitumen from oil sands froth treatment tailings. *Canadian Journal of Chemical Engineering, 91*(8), 1383-1394.

Morgenstern, N. R. & Scott, J. D. (1997). Oil Sand Geotechnique. *Geotechnical News, Special 1997*, 102-109.

Morgenstern, N. R. (2010). *Improving the Safety of Mine Waste Impoundments.* Paper presented at 14th International Conference on Tailings and Mine Waste, Vail (CO).

Morgenstern, N. R. (2012). *Oil Sands Mine Closure - The End Game: An Update.* Paper presented at Third International Oil Sands Tailings Conference, Edmonton (AB).

MRBB (Mackenzie River Basin Board). (2013). *2012 Issues Report: Oil Sands Development, Hydroelectric Development, and Climate Change in the Mackenzie River Basin.* Yellowknife (NT): MRBB.

Muller, N. Z. & Mendelsohn, R. (2007). Measuring the damages of air pollution in the United States. *Journal of Environmental Economics and Management, 54*(1), 1-14.

Mutyala, S., Fairbridge, C., Pare, J. R. J., Belanger, J. M. R., Ng, S., & Hawkins, R. (2010). Microwave applications to oil sands and petroleum: A review. *Fuel Processing Technology, 91*(2), 127-135.

N-Solv Corporation. (2014a). Home Page. Retrieved April 2014, from http://www.n-solv.com/.

N-Solv Corporation. (2014b). Key N-Solv™ Technology Principles. Retrieved April 2014, from http://www.n-solv.com/technology.php.

Natural Resources Canada. (2013). Upgrading and Refining Process Development. Retrieved April 2014, from http://www.nrcan.gc.ca/energy/oil-sands/upgrading/5879.

Nduagu, E. & Gates, I. D. (2014). An ultra-low emissions enhanced thermal recovery process for oil sands in energy. *Energy Procedia, 63*, 8050-8061.

Neal, W. H. (2007). *Topic Paper #26: Oil and Gas Technology Development*. Washington (DC): National Petroleum Council.

NEB (National Energy Board). (2013). *Canada's Energy Future 2013 - Energy Supply and Demand Projections to 2035*. Calgary (AB): NEB.

NETL (National Energy Technology Laboratory). (n.d.). Carbon Storage Technology. Retrieved September 2014, from http://www.netl.doe.gov/research/coal/carbon-storage/.

Neufeld, L. (2014). *Progressive land reclamation as the design and operational basis for the Kearl Oil Sands Mine*. Paper presented at SPE International Conference on Health, Safety, and Environment, Long Beach (CA).

Nexen. (2014). 2013 Sustainability Report. Retrieved September 2014, from http://www.nexencnoocltd.com/en/ResponsibleDevelopment/SustainabilityReport.aspx.

Nikakhtari, H., Vagi, L., Choi, P., Liu, Q., & Gray, M. R. (2013). Solvent screening for non-aqueous extraction of Alberta oil sands. *Canadian Journal of Chemical Engineering, 91*(6), 1153-1160.

Nikakhtari, H., Wolf, S., Choi, P., Liu, Q., & Gray, M. R. (2014). Migration of Fine Solids into Product Bitumen from Solvent Extraction of Alberta Oilsands. *Energy Fuels, 28*, 2925-2932.

NineSights. (2014). CCEMC Grand Challenge: Innovative Carbon Uses. Retrieved April 2014, from https://www.ninesights.com/community/ccemc/grand-challenge.

Noss, R. F. (1983). A Regional Landscape Approach to Maintain Diversity. *Bioscience, 33*(11), 700-706.

Noss, R. F. (1990). Indicators for monitoring biodiversity: A hierarchical approach. *Conservation Biology, 4*(4), 355-364.

Oil Sands Tailings Dam Committee. (2014). *De-licensing of Oil Sands Tailings Dams*. Fort McMurray (AB): Oil Sands Tailings Dam Committee.

Oil Sands Today. (2014). GHG Emissions. Retrieved September 2014, from http://www.oilsandstoday.ca/topics/ghgemissions/Pages/default.aspx.

Oilsands Review. (2015). Oilsands Glossary. Retrieved February 2015, from http://www.oilsandsreview.com/page.asp?id=glossary.

Ordorica-Garcia, G., Nikoo, M., Carbo, M., & Bolea, I. (2012). Technology options and integration concepts for implementing CO_2 capture in oil-sands operations. *Journal of Canadian Petroleum Technology, September 2012*, 362-375.

OSTC & COSIA (Oil Sands Tailings Consortium & Canada's Oil Sands Innovation Alliance). (2012). *Technical Guide for Fluid Fine Tailings Management*. Calgary (AB): COSIA.

Ovalles, C., Vallejos, C., Vasquez, T., Rojas, I., Ehrman, U., Benitez, J. L., & Martinez, R. (2003). Downhole upgrading of extra-heavy crude oil using hydrogen donors and methane under steam injection conditions. *Petroleum Science and Technology, 21*, 255-274.

Painter, P., Williams, P., & Mannebach, E. (2010). Recovery of bitumen from oil or tar sands using ionic liquids. *Energy and Fuels, 24*(3), 1094-1098.

Parreira, J. & Meech, J. (2012). Simulation of autonomous mine haulage trucks.

Parsons, M., McLennan, D., Lapalme, M., Mooney, C., Watt, C., & Mintz, R. (2013). Total gaseous mercury concentration measurements at Fort McMurray, Alberta, Canada. *Atmosphere, 4*(4), 472-493.

Pembina Institute. (2009). *Greening the Grid: Powering Alberta's Future with Renewable Energy*. Drayton Valley (AB): Pembina Institute.

Pembina Institute. (2013a). *Losing Ground: Why the Problem of Oilsands Tailings Waste Keeps Growing*. Calgary (AB): Pembina Institute.

Pembina Institute. (2013b). What You Need to Know About Alberta's 40/40 Carbon Pricing Proposal. Retrieved February 2015, from http://www.pembina.org/blog/707.

Pembina Institute. (2013c). *Strengthening Alberta's Greenhouse Gas Regulations*. Calgary (AB): Pembina Institute.

Pembina Institute. (2013a). *Forecasting the Impacts of Oilsands Expansion*. Calgary (AB): Pembina Institute.

Pembina Institute. (2014a). Alberta's Oilsands. Retrieved September 2014, from http://www.pembina.org/oil-sands/os101/alberta.

Pembina Institute. (2014b). *Climate Change Policy in Alberta*. Calgary (AB): Pembina Institute.

Percy, K. E., Hansen, M. C., & Dann, T. (2012). Chapter 4 - Air Quality in the Athabasca Oil Sands Region 2011. In E. P. Kevin (Ed.), *Developments in Environmental Science* (Vol. Volume 11): Elsevier.

Percy, K. E. (2013). Geoscience of climate and energy: Ambient air quality and linkage to ecosystems in the Athabasca oil sands, Alberta. *Geoscience Canada, 40*(3), 182-201.

Percy, K. E. (Ed.). (2012). *Alberta Oil Sands: Energy, Industry and the Environment*. Oxford, United Kingdom: Elsevier.

Pereira Almao, P. (2012). In Situ Upgrading of Bitumen and Heavy Oils Via Nanocatalysis. *The Canadian Journal of Chemical Engineering, 90*, 320-329.

Pollard, J., McKenna, G. T., Fair, J., Daly, C., Wytrykush, C., & Clark, J. (2012). *Design Aspects of Two Fen Wetlands Constructed for Reclamation Research in the Athabasca Oil Sands*. Paper presented at Mine Closure 2012 Symposium, Brisbane, Australia.

Popp, D. (2002). Induced innovation and energy prices. *The American Economic Review, 92*(1), 160-180.

Popp, D. (2006). International innovation and diffusion of air pollution control technologies: The effects of NO_x and SO_2 regulation in the U.S., Japan, and Germany. *Journal of Environmental Economics and Management, 51*(1), 46-71.

Popp, D., Newell, R. G., & Jaffe, A. B. (2010). Energy, the Environment, and Technological Change. In B. H. Hall & N. Rosenberg (Eds.), *Handbook of the Economics of Innovation* (Vol. 2). Amsterdam, North Holland: Academic Press.

Puttawswamy, N. V. (2011). Evaluation of Metals Release from Oil Sands Coke: An Ecotoxicological Assessment of Risk and Hazard to Aquatic Invertebrates. *Ph.D. Thesis.* Saskatoon (SK): College of Graduate Studies and Research, University of Saskatchewan.

Quagraine, E. K., Peterson, H. G., & Headley, J. V. (2005). In situ bioremediation of naphthenic acids contaminated tailing pond waters in the Athabasca Oil Sands Region – demonstrated field studies and plausible options: A review. *Journal of Environmental Science and Health - Part A Toxic/Hazardous Substances and Environmental Engineering*(131), 434-442.

RAMP (Regional Aquatics Monitoring Program). (2014). *2013 Technical Report.* Edmonton (AB): RAMP.

Rasouli, K., Hernández-Henríquez, M. A., & Déry, S. J. (2013). Streamflow input to Lake Athabasca, Canada. *Hydrology and Earth System Sciences, 17*, 1681-1691.

Read, P. (2014). *Broad Suite of Practice and Technology Key to Success in Tailings Management.* Paper presented at Fourth International Oil Sands Tailings Conference, Lake Louise (AB).

Rogers, E. M. (2004). Issues with Using Process-Affected Water (Scaling, Corrosion and Fouling). Fort McMurray (AB): Canadian Oil Sands Network for Research and Development (CONRAD) Water Usage Workshop.

RSC (The Royal Society of Canada). (2010). *Environmental and Health Impacts of Canada's Oil Sands Industry.* Ottawa (ON): RSC.

Russell, B., McKenna, G., LeBlanc, M., Wells, P. S., & Anderson, H. B. (2010). *Design and Construction of the Reclamation Surface for the First Oil Sands Tailings Pond.* Paper presented at Mines Closure 2010, Vina del Mar, Chile.

Sarkar, S. & Kumar, A. (2010). Biohydrogen production from forest and agricultural residues for upgrading of bitumen from oil sands. *Energy, 35*(2), 582-591.

SaskPower. (2012). *Boundary Dam Integrated Carbon Capture and Storage Demonstration Project.* Regina (SK): SaskPower.

Schindler, D. W. & Donahue, W. F. (2006). An impending water crisis in Canada's western prairie provinces. *Proceedings of the National Academy of Sciences, 103*(19), 7210-7216.

Schindler, D. W. (2013). Geoscience of climate and energy: Water quality issues in the oil sands region of the lower Athabasca River, Alberta. *Geoscience Canada, 40*(3), 202-214.

Schneider, R. & Dyer, S. (2006). *Death by a Thousand Cuts: Impacts of In Situ Oil Sands Development on Alberta's Boreal Forest.* Edmonton (AB): Canadian Parks and Wilderness Society and The Pembina Institute.

Scott, N. (2006, October). Tailings Twist, *Oilsands Review.*

SDTC (Sustainable Development Technology Canada). (n.d.). SDTC Portfolio. Retrieved September 2014, from http://www.sdtc.ca/uploads/Portfolio_English.html.

Shell Canada Ltd. (2005). Application for Approval of the Scotford Upgrader Expansion Project: Project Description (Vol. 1). Calgary (AB): Shell Canada Ltd.

Shell Canada Ltd. (2007). Application for the Approval of the Shell Scotford Upgrader 2 Project. *Submitted to the Alberta Energy and Utilities Board.* Calgary (AB): Shell Canada Ltd.

Shell Canada Ltd. (2012a). *Muskeg River Mine Annual Tailings Management Plan 2013.* Fort McMurray (AB): Energy Resources Conservation Board.

Shell Canada Ltd. (2012b). *Jackpine Mine Annual Tailings Management Plan 2013.* Fort McMurray (AB): Energy Resources Conservation Board.

Shell Canada Ltd. (2014). Athabasca Oil Sands Project – Scotford Upgrader and Quest CCS. Retrieved April 2014, from http://www.shell.ca/en/aboutshell/our-business-tpkg/upstream/oil-sands/scotford-upgrader.html.

Shell Global. (2014). Extracting Heavy Oil. Retrieved December 2014, from http://www.shell.com/global/future-energy/innovation/inspiring-stories/extracting-heavy-oil.html.

Slovic, P. (2000). *The Perception of Risk.* London, United Kingdom: Routledge.

Sobkowicz, J. C. (2013). *The Oil Sands Tailings Technology Roadmap and Action Plan: Introduction and Key Recommendations.* Paper presented at Third International Oil Sands Tailings Conference, Lake Louise (AB).

Souraki, Y., Ashrafi, M., Jahanbani Ghahfarokhi, A., & Torsater, O. (2013). *Application of Solvent Alternating SAGD Process to Improve SAGD Performance in Athabasca Bitumen Reservoir.* Paper presented at SPE Western Regional & AAPG Pacific Section Meeting, 2013 Joint Technical Conference, Monterey (CA).

Sparks, B., Meadus, F., & Kumar, A. (1992). The effect of asphaltene content on solvent selection for bitumen extraction by the SESA process. *Fuel, 71*(12), 1349-1353.

Speight, J. G. (2013). *Oil Sand Production Processes.* Amsterdam, Netherlands: Elsevier.

Squires, A. J., Westbrook, C. J., & Dubé, M. G. (2010). An approach for assessing cumulative effects in a model river, the Athabasca River basin. *Integrated Environmental Assessment and Management, 6*(1), 119-134.

St. Louis, V. L., Kelly, C. A., Duchemin, E., Rudd, J. W. M., & Rosenberg, D. M. (2000). Reservoir surfaces as sources of greenhouse gases to the atmosphere: A global estimate. *BioScience, 50*(9), 766-775.

Stalder, J. L. (2012). *Test of SAGD Flow Distribution Control Liner System, Surmont Field, Alberta, Canada.* Paper presented at SPE Western Regional Meeting, Bakersfield (CA).

Stark, S. D. (2013). *Cold Lake Commercialization of the Liquid Addition to Steam for Enhancing Recovery (LASER) Process.* Paper presented at International Petroleum Technology Conference, Beijing, China.

Statistics Canada. (2014). *Industrial Research and Development: Intentions.* Ottawa (ON): Statistics Canada.

Stephens, B., Langton, C., & Bowron, M. (2012). *Design of Tailings Dams on Large Pleistocene Channel Deposits A Case Study - Suncor's South Tailings Pond.* Montréal (QC): Commission for Environmental Cooperation.

Studabaker, W. B., Krupa, S., Jayanty, R. K. M., & Raymer, J. H. (2012). Measurement of Polynuclear Aromatic Hydrocarbons (PAHs) in Epiphytic Lichens for Receptor Modeling in the Alberta Oil Sands Region: A Pilot Study. In K. E. Percy (Ed.), *Alberta Oil Sands: Energy, Industry and the Environment.* Oxford, United Kingdom: Elsevier.

Suncor Energy Inc. (2012). *2013 Annual Tailings Management Plan.* Fort McMurray (AB): Energy Resources Conservation Board.

Suncor Energy Inc. & Jacobs Consultancy Canada Inc. (2012). *A Greenhouse Gas Reduction Roadmap for Oil Sands.* Edmonton (AB): Climate Change Emissions Management Corporation and Alberta Innovates - Energy and Environment Solutions.

Suncor Energy Inc. (2013a). *Suncor Firebrag: 2013 ERCB Performance Presentation Commercial Scheme Approval No. 8870.* Calgary (AB): Alberta Energy Regulator.

Suncor Energy Inc. (2013b). *Report on Sustainability 2013.* Calgary (AB): Suncor Energy Inc.

Suncor Energy Inc. (2014a). *Suncor Firebag 2014 AER Performance Presentation: Commercial Scheme Approval No. 8870.* Calgary (AB): Alberta Energy Regulator.

Suncor Energy Inc. (2014b). *Investor Information (February 3, 2014).* Calgary (AB): Suncor Energy Inc.

Syncrude Canada Ltd. (2007). *2006 Sustainability Report.* Fort McMurray (AB): Syncrude Canada Ltd.

Syncrude Canada Ltd. (2011). *2011 Annual Tailings Plan Submission Syncrude Aurora North.* Fort McMurray (AB): Energy Resources Conservation Board.

Syncrude Canada Ltd. (2012). *2012 Annual Tailings Plan Submission Syncrude Mildred Lake Mine.* Fort McMurray (AB): Energy Resources Conservation Board.

Syncrude Canada Ltd. (2014). Ongoing Projects. Retrieved December 2014, from http://www.syncrude.ca/environmental-commitment/land-reclamation/ongoing-projects/.

Teck Resources Limited & SilverBirch Energy Corporation. (2011). *Frontier Oil Sands Mine Project - Environment Impact Statement.* Vol. 1-8. Ottawa (ON): Canadian Environmental Assessment Agency (CEAA).

Tellez, G. T., Nirmalakhandan, N., & Gardea-Torresdey, J. L. (2002). Performance evaluation of an activated sludge system for removing petroleum hydrocarbons from oilfield produced water. *Advances in Environmental Research*(6), 455-470.

The ecoENERGY Carbon Capture and Storage Task Force. (2008). *Canada's Fossil Energy Future: The Way Forward on Carbon Capture and Storage.* Edmonton (AB) and Ottawa (ON): Alberta Government and Government of Canada.

Timoney, K. & Lee, P. (2009). Does the Alberta tar sands industry pollute? The scientific evidence. *The Open Conservation Biology Journal, 3,* 65-81.

Touchstone Exploration Inc. (2014). Operations: Kerrobert - Luseland. Retrieved November 2014, from http://www.touchstoneexploration.com/operations/canada/heavy-oil/kerrobert.

U.S. Department of the Interior. (2012). What is the Biggest Dam in the World? Retrieved February 2015, from http://www.usbr.gov/lc/hooverdam/History/essays/biggest.html.

Vandenberg, J. A. (2014). *Planning for Canada's Future Oil Sands Pit Lakes: An Overview of the COSIA Demonstration Pit Lakes Projects.* Paper presented at Geological Society of America Annual Meeting, Vancouver (BC).

Vanderklippe, N. (2012, October 3). Ambitious Plans for Oil Sands Would Create Lakes from Waste, *The Globe and Mail.*

Vick, S. G. (1990). *Planning, Design, and Analysis of Tailings Dams* (2nd ed.). Vancouver (BC): BiTech.

Vincent-Lambert, W., Bowron, M., Langton, C., & Stephens, B. (2011). *Groundwater Control for Tailings Dams Built on Large Pleistocene Channel Deposits: A Case Study of Integrated Systems at Suncor's South Tailings Pond.* Paper presented at Tailings and Mine Waste Conference, Vancouver (BC).

Vinegar, H. J., de Rouffignac, E. P., Karanikas, J. M., Maher, K. A., Sumnu-Dindoruk, M. D., Wellington, S. L., . . . Roberts, B. E. (2006). In Situ Thermal Processing of a Tar Sands Formation *US Patent 7066254*: Google Patents.

Wacker, B., Karmeileopardus, D., Trautmann, B., Helget, A., & Torlak, M. (2011). *Electromagnetic Heating for In-Situ Production of Heavy Oil and Bitumen Reservoirs.* Paper presented at Canadian Unconventional Resources Conference, Calgary (AB).

Wagner, J. & Kresnyak, S. (2013). *Bitumen Upgrader Residue Conversion to Incremental Synthetic Fuels Products.* Calgary (AB): Expander Energy Inc.

Walden, Z. (2011). *Emission Abatement Potential for the Alberta Oil Sands Industry and Carbon Capture and Storage (CCS) Applicability to Coal-Fired Electricity Generation and Oil Sands.* Calgary (AB): Canadian Energy Research Institute.

Wang, L., Zachariah, A., Yang, S., Prasad, V., & De Klerk, A. (2014). Visbreaking oilsands-derived bitumen in the temperature range of 340–400°C. *Energy Fuels, 28*(8), 5014-5022.

Warren, F. J. & Lemmen, D. S. (2014). *Canada in a Changing Climate: Sector Perspectives on Impacts and Adaptation.* Ottawa (ON): Government of Canada.

Watmough, S. A., Whitfield, C. J., & Fenn, M. E. (2014). The importance of atmospheric base cation deposition for preventing soil acidification in the Athabasca Oil Sands Region of Canada. *The Science of the Total Environment, 493*, 1-11.

Watson, J. G., Chow, J. C., Wang, X. L., Kohl, S. D., Chen, L.-W. A., & Etyemezian, V. (2012). Overview of Real-World Emission Characterization Methods, 145-170. In K. E. Percy (Ed.), *Alberta Oil Sands: Energy, Industry and the Environment.* Oxford, United Kingdom: Elsevier.

Watson, J. G., Chow, J. C., Wang, X., Kohl, S. D., & Sodeman, D. A. (2013a). *Measurement of Real-World Stack Emissions in the Athabasca Oil Sands Region with a Dilution Sampling System During August, 2008.* Fort McMurray (AB): Wood Buffalo Environmental Association.

Watson, J. G., Chow, J. C., Wang, X., Lowenthal, D., Kohl, S. D., & Gronstal, S. (2013b). *Characterization of Real-World Emission from Non-Road Mining Trucks in the Athabasca Oil Sands Region During October, 2010.* Fort McMurray (AB): Wood Buffalo Environmental Association.

Watson, J. G., Chow, J. C., Wang, X., Kohl, S. D., & Yatavelli, L. N. R. (2014). *Windblown Fugitive Dust Characterization in the Athabasca Oil Sands Region.* Fort McMurray (AB): Wood Buffalo Environmental Association.

WBEA (Wood Buffalo Environmental Association). (2003). *Analysis of Water Quality of Steepbank, Firebag and Muskeg.* Fort McMurray (AB): WBEA.

WBEA (Wood Buffalo Environmental Association). (2015a). Air Monitoring. Retrieved January 2015, from http://www.wbea.org/air-monitoring.

WBEA (Wood Buffalo Environmental Association). (2015b). *Wood Buffalo Environmental Association Annual Report 2013.* Fort McMurray (AB): WBEA.

Weber, B. (2014, February 20). Federal Study Says Oil Sands Toxins are Leaching into Groundwater, Athabasca River, *The Globe and Mail.*

Weitzman, M. L. (1974). Prices vs. Quantities. *The Review of Economic Studies,* 41(4), 477-491.

Wells, P. S., Caldwell, J., & Fournier, J. (2010). *Suncor Pond 5 Coke Cap - The Story of its Conception, Testing, and Advance to Full-Scale Construction.* Paper presented at Tailings and Mine Waste Conference, Vail (CO).

Whitfield, C. J., Aherne, J., & Watmough, S. A. (2009). Modeling soil acidification in the Athabasca oil sands region, Alberta, Canada. *Environmental Science and Technology, 43*(15), 5844-5850.

Whitfield, C. J., Adkinson, A., Eimers, M. C., & Watmough, S. A. (2010a). The adsorption and release of sulfur in mineral and organic soils of the Athabasca oil sands region, Alberta, Canada. *Journal of Environmental Quality, 39*(3), 1108-1112.

Whitfield, C. J., Aherne, J., Watmough, S. A., & McDonald, M. (2010b). Estimating the sensitivity of forest soils to acid deposition in the Athabasca oil sands region, Alberta. *Journal of Limnology, 69* (Suppl. 1), 201-208.

Wiklund, J. A., Hall, R. I., Wolfe, B. B., Edwards, T. W. D., Farwell, A. J., & Dixon, D. G. (2012). Has Alberta oil sands development increased far-field delivery of airborne contaminants to the Peace-Athabasca Delta? *Science of the Total Environment, 433,* 379-382.

Winfield, M. S. (2007, Jan. 24). Nuclear Power No Solution for Oilsands, *Edmonton Journal.*

Wu, J. & Dabros, T. (2012). Process for solvent extraction of bitumen from oil sand. *Energy Fuels, 26*(2), 1002-1008.

Xu, Y., Dabros, T., & Kan, J. (2008). Filterability of oil sands tailings. *Process Safety and Environmental Protection, 86*(4), 268-276.

Xu, Y., Dabros, T., & Kan, J. (2013a). Investigation on alternative disposal methods for froth treatment tailings: Part 1, disposal without asphaltene recovery. *The Canadian Journal of Chemical Engineering, 91* (August 2013), 1349-1357.

Xu, Y., Wu, J., Dabros, T., Rahimi, P., & Kan, J. (2013b). Investigation on alternative disposal methods for froth treatment tailings: Part 2, recovery of asphaltene. *The Canadian Journal of Chemical Engineering, 91* (August 2013), 1358-1364.

Yang, D., Hosseininejad, M., Brand, S., & Bennett, C. (2014). Thermal recovery of bitumen from the Grosmont Carbonate Formation - Part 2: Pilot interpretation and development strategy. *Journal of Canadian Petroleum Technology, 53*(4), 212-223.

Ye, J. (2014). *Comparison of Carbon Pricing Proposals in the 113th Congress.* Arlington (VA): Center for Climate and Energy Solutions.

Younger, P. L., Banwart, S. A., & Hedin, R. S. (2002). *Mine Water: Hydrology, Pollution and Remediation.* Cornwall, United Kingdom: Kluwer Academic Publishers.

Zhang, C., Alostaz, M., Beier, N. A., & Sego, D. (2010). *Cross Flow Filtration of Oil Sands Total Tailings.* Paper presented at Tailings and Mine Waste Conference, Vail (CO).

Zhu, Z. & Zeng, F. (2012). *Evaluation of the Hybrid Process of Electrical Resistive Heating and Solvent Injection Through Numerical Simulations.* Paper presented at SPE Heavy Oil Conference Canada, Calgary (AB).

Zubot, W., MacKinnon, M. D., Chelme-Ayala, P., Smith, D. W., & Gamal El-Din, M. (2012). Petroleum coke adsorption as a water management option for oil sands process-affected water. *Science of the Total Environment, 427-428* (June 2012), 364-372.

Assessments of the Council of Canadian Academies

The assessment reports listed below are accessible through the Council's website (www.scienceadvice.ca):

- Technological Prospects for Reducing the Environmental Footprint of Canadian Oil Sands
- Some Assembly Required: STEM Skills and Canada's Economic Productivity (2015)
- Understanding the Evidence: Wind Turbine Noise (2015)
- Accessing Health and Health-Related Data in Canada (2015)
- Leading in the Digital World: Opportunities for Canada's Memory Institutions (2015)
- Policing Canada in the 21st Century: New Policing for New Challenges (2014)
- Energy Prices and Business Decision-Making in Canada: Preparing for the Energy Future (2014)
- Improving Medicines for Children in Canada (2014)
- Science Culture: Where Canada Stands (2014)
- Enabling Sustainability in an Interconnected World (2014)
- Environmental Impacts of Shale Gas Extraction in Canada (2014)
- Aboriginal Food Security in Northern Canada: An Assessment of the State of Knowledge (2014)
- Ocean Science in Canada: Meeting the Challenge, Seizing the Opportunity (2013)
- The Health Effects of Conducted Energy Weapons (2013)
- The State of Industrial R&D in Canada (2013)
- Innovation Impacts: Measurement and Assessment (2013)
- Water and Agriculture in Canada: Towards Sustainable Management of Water Resources (2013)
- Strengthening Canada's Research Capacity: The Gender Dimension (2012)
- The State of Science and Technology in Canada (2012)
- Informing Research Choices: Indicators and Judgment (2012)
- Integrating Emerging Technologies into Chemical Safety Assessment (2012)
- Healthy Animals, Healthy Canada (2011)
- Canadian Taxonomy: Exploring Biodiversity, Creating Opportunity (2010)
- Honesty, Accountability, and Trust: Fostering Research Integrity in Canada (2010)

- Better Research for Better Business (2009)
- The Sustainable Management of Groundwater in Canada (2009)
- Innovation and Business Strategy: Why Canada Falls Short (2009)
- Vision for the Canadian Arctic Research Initiative: Assessing the Opportunities (2008)
- Energy from Gas Hydrates: Assessing the Opportunities and Challenges for Canada (2008)
- Small Is Different: A Science Perspective on the Regulatory Challenges of the Nanoscale (2008)
- Influenza and the Role of Personal Protective Respiratory Equipment: An Assessment of the Evidence (2007)
- The State of Science and Technology in Canada (2006)

The assessments listed below are in the process of expert panel deliberation:

- RISK: Is the Message Getting Through?
- Energy Use and Climate Change: A Synthesis of the Latest Evidence

Board of Governors of the Council of Canadian Academies*

Margaret Bloodworth, C.M., Chair, Former Federal Deputy Minister and National Security Advisor (Ottawa, ON)

Graham Bell, FRSC, President, Royal Society of Canada; Research Director, James McGill Professor, Chair, Department of Biology, McGill University (Montréal, QC)

John Cairns, FCAHS, President, Canadian Academy of Health Sciences; Professor of Medicine, University of British Columbia (Vancouver, BC)

Henry Friesen, C.C., FRSC, FCAHS, Vice Chair, Distinguished Professor Emeritus and Senior Fellow, Centre for the Advancement of Medicine, Faculty of Medicine, University of Manitoba (Winnipeg, MB)

Carol P. Herbert, FCAHS, Professor of Family Medicine, Western University (London, ON)

Claude Jean, Executive Vice President and General Manager, Foundry Operation, Semiconductor, Teledyne DALSA (Bromont, QC)

Peter MacKinnon, O.C., Former President and Vice-Chancellor, University of Saskatchewan (Saskatoon, SK)

Jeremy McNeil, FRSC, Helen Battle Professor of Chemical Ecology, Western University (London, ON)

Axel Meisen, C.M., FCAE, Former Chair of Foresight at Alberta Innovates — Technology Futures (AITF) (Edmonton, AB)

Lydia Miljan, Associate Professor of Political Science and Chair of the Arts and Science Program, University of Windsor (Windsor, ON)

Ted Morton, Executive Fellow at the School of Public Policy, Professor of Political Science, University of Calgary (Calgary, AB)

P. Kim Sturgess, FCAE, CEO and Founder, Alberta WaterSMART (Calgary, AB)

* Affiliations as of March 2015

Scientific Advisory Committee of the Council of Canadian Academies*

Susan A. McDaniel, FRSC, Chair, Director, Prentice Institute & Canada Research Chair in Global Population & Life Course, Prentice Research Chair & Professor of Sociology, University of Lethbridge (Lethbridge, AB)

Lorne Babiuk, O.C., FRSC, FCAHS, Vice President (Research), University of Alberta (Edmonton, AB)

Murray S. Campbell, Senior Manager, AI and Optimization, IBM T.J. Watson Research Center (Yorktown Heights, NY)

Clarissa Desjardins, CEO, Clementia Pharmaceuticals Inc. (Montréal, QC)

Jean Gray, C.M., FCAHS, Professor of Medicine (Emeritus), Dalhousie University (Halifax, NS)

John Hepburn, FRSC, Vice-President, Research and International, University of British Columbia (Vancouver, BC)

Gregory S. Kealey, FRSC, Professor, Department of History, University of New Brunswick (Fredericton, NB)

Daniel Krewski, Professor of Epidemiology and Community Medicine and Scientific Director of the McLaughlin Centre for Population Health Risk Assessment, University of Ottawa (Ottawa, ON)

Avrim Lazar, Former President and CEO, Forest Products Association of Canada (Ottawa, ON)

Norbert R. Morgenstern, C.M., FRSC, FCAE, University Professor (Emeritus), Civil Engineering, University of Alberta (Edmonton, AB)

Sarah P. Otto, FRSC, Professor and Director of the Biodiversity Research Centre, University of British Columbia (Vancouver, BC)

*Affiliations as of March 2015

Council of Canadian Academies
Conseil des académies canadiennes

Council of Canadian Academies
180 Elgin Street, Suite 1401
Ottawa, ON K2P 2K3
Tel: 613-567-5000
www.scienceadvice.ca