PETROLEUM TECHNOLOGY ALLIANCE CANADA

Facilitating innovation, collaborative research and technology development, demonstration and deployment for a responsible Western Canadian upstream hydrocarbon energy industry.

Expanding Heavy Oil and Bitumen Resources while Mitigating GHG Emissions and Increasing Sustainability

A Technology Roadmap

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Acknowledgements and Disclaimer

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Disclaimers

This document is **intended as an initial assessment** of technology and R&D directions and potential needs assessment processes. Any specific technologies, or applications, discussed or referred to are intended as examples of potential solutions or solution areas, and have not been assessed in detail, or endorsed as to their technical or economic viability.

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1. Executive Summary

Purpose - This study was commissioned by Natural Resources Canada (NRCan), in support of the Climate Change Technology Innovation Initiative (CCTII), with the objective of identifying new R&D directions for oil sands production processes. The new processes should have the potential to reduce GHG intensities, and improve the sustainability of producing the expanded resource base. This initial, Phase I, or high-level roadmap, is intended to stimulate "exploratory" investigations, into these new directions, which can then be used to develop a more detailed, or Phase II, road map.

Scope of the Study - The "inaccessible" bitumen and heavy oil resources, in Western Canada, are vast, amounting to over 150 billion m^3 (900 billion barrels). However, they are contained in deposits, which will present new and unique challenges that are unlikely to be met with incremental improvements to existing processes. Inaccessible resources include bitumen in carbonates, thin or uncontained pay zones, oil remaining in primary production areas, and small deposits under tailings, or outside of the main oil sands area of Alberta. Expansion into these new deposits will require new technologies, and/or step-change improvements in the application of existing technologies, to enable orderly development in a manner that is sustainable, and achievable with minimal GHG emissions.

Long-term R&D Directions - This high-level road map has identified a number of potentially promising new R&D directions, which could result in significant long-term gains in making "inaccessible" oil sands deposits, "accessible" for development. Figure 1.1 summarizes the key R&D directions, and indicates relative priorities assessed by steering committee members:

New R&D Directions – These R&D issues have been raised in the past, but have not been significantly targeted for recent research efforts, as they are not required for the economic recovery of the rich, thick and easily accessible oil sands currently under development.

- **Alternate Recovery Processes (Priority #1)** – Potential R&D targets are processes ranging from the use of hot combustion gases, and direct contact steam generation, to in-situ reactors, and energy/hydrocarbon scavenging after initial recovery.
- **Building/Breaking Barriers (Priority #4) –** Most processes contemplated for bitumen recovery require that the deposits be contained, to maintain recovery efficiencies. Bitumen deposits are unique in that containment is not assured, as the hydrocarbons are held in place by their properties. Therefore, once the bitumen can flow, containment may be lost. Breaking barriers, to improve permeability, or building barriers, to prevent loss of injected fluids or avoid free inflow of water, will be needed.

- **Alternate Mining and Access Methods (Priority #7)** – A number of sub-surface mining methods have the potential to be adapted to bitumen deposits, to either improve access, mine the ore for processing, or to remove enough of the ore to enhance the performance of other in-situ recovery methods.

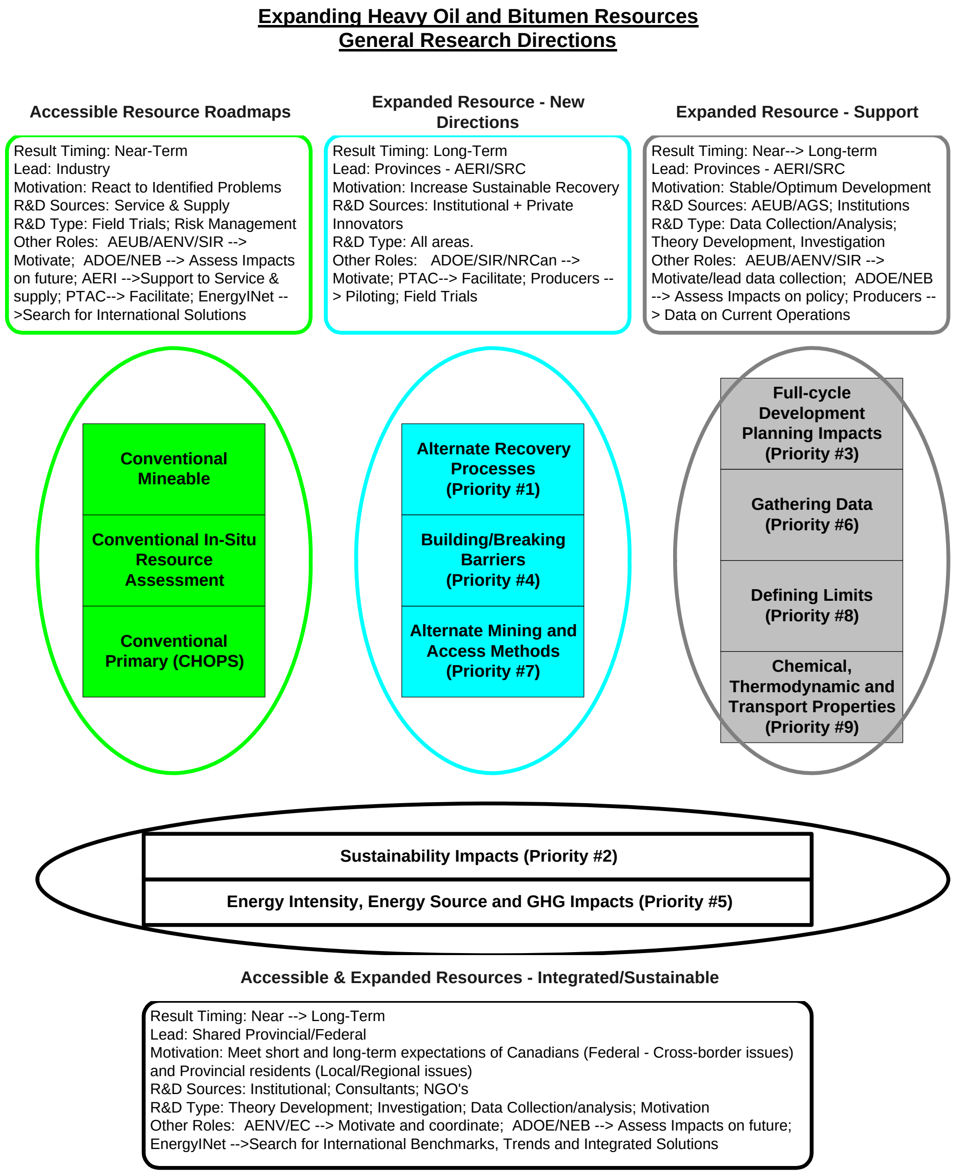


Figure 1.1 – Heavy Oil and Bitumen Resource Expansion – Key R&D Directions

Sustainability R&D – This is R&D related to resource development, both existing and future, which impacts the processes selected to optimally meet the needs of all stakeholders in the development. R&D directions include:

- **Sustainability Impacts (Priority #2) -** Covers environmental, economic and security issues, which can have large effects on local, regional, national and international stakeholders.

- **Energy Intensity, Energy Source and GHG impacts (Priority #5) –** These areas are all closely related, and are significantly impacted, by the resource recovery methods and technologies used, as well as by the deposit location.

Support Technology and Data – While the AEUB and others have made some assessment of the "inaccessible" resource base, these resources are still poorly defined. Support R&D directions include:

- **Full-cycle Development Planning (Priority #3) -** Needed to consider staging of technologies for recovery, as the resource is depleted, and to maximize hydrocarbon energy recoveries, while minimizing negative impacts.
- **Gathering Data (Priority #6) -** Key deposit areas require better information, before development begins, such as: mapping the "texture", or distribution of barriers, quality, frequency of changes in deposit properties of the oil sands, groundwater penetration, etc.; flow barrier assessments; water sources and groundwater; and improving understanding of factors affecting current recovery processes.
- **Defining Limits (Priority #8) –** Includes understanding which deposits are, or may be, "uncontained", the state of post-CHOPS reservoirs, carbonate deposit characteristics, and thin oil sands. How extensive are these types of deposits, and what are the limits of current technologies to recover bitumen or heavy oil from them?
- **Chemical, Thermodynamic and Transport Properties (Priority #9) -** Are critical to assessing the potential impacts of new processes, in new deposits, under new conditions. Insights are needed to allow low cost and low impact development.

Benefits - Many of the technologies, or R&D directions, identified in this report, may also provide short-term or medium-term benefits, through:

- Allowing early **development of "sweet spots"** in each of the deposits, which may be more advantageous to develop than lower quality "accessible" resources.
- Developing options, such as barrier construction methods, to **mitigate risks** to SAGD and other projects, in deposits, which may or may not be confined.
- Reducing environmental and GHG impacts, through technologies to **increase efficiency**, such as direct contact steam generation (reduces water, fuel use and GHG emissions), or the identification of new options to assist development of "accessible" resources.
- Investigation and motivation activities to assess methods of **optimizing long-term development**, which are needed to address growing infrastructure, labour, environmental and cost-escalation

issues being encountered with current developments, and which are likely to continue as the resource expands.

- R&D for the long-term, in areas such as surface extraction methods and tailings reduction, which can be justified based on the prize of **extending the mineable resource** to highwalls accessed from current surface mines, and in-situ mining assisted operations.
- Data from historical and current operations, which would support **improvements to future production** from "accessible resources", as well as assessing processes for new deposits.
- Opening up the 70-75% of the oil sands area that has not yet been leased[1] which may help to **distribute development** over a larger area of the province.

Justification for Long-term R&D Investment - The vast resources of the oil sands require a significant, and efficient, investment in long-term R&D, to ensure that production can be sustained well into the future. At the same time, such efforts can help to minimize resource losses, and possible adverse impacts of development in the near-term. Currently there is very little R&D infrastructure for large-scale physical models, insufficient incentives for necessary theory development, data collection, investigation, field trials, and piloting, on a scale that is likely to provide meaningful results for such a massive resource.

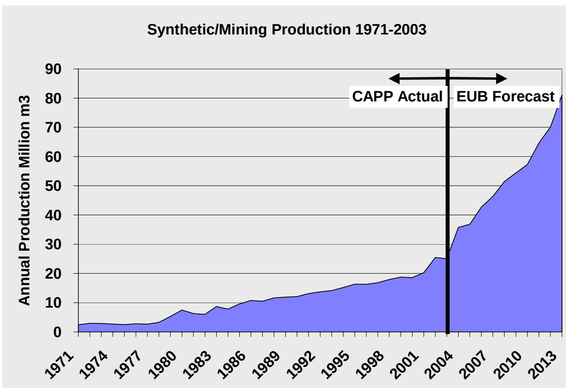
Current Funding Inadequate - Current, government funded R&D expenditures are approximately 10% of annual oil sands royalty revenues, however, they are only about 0.15% of the $11 billion dollars of bitumen sales revenues the producers received in 2003. Even assuming a 6:1 leverage, of industry research to government research, the total combined effort is still less than 1% of the current revenue stream, and dropping as oil prices and production volumes continue to rise. Much of the R&D, that is done, is for short-term needs, to react to issues, rather than proactively avoid them.

Managing R&D - R&D also requires increased planning, impact studies, tool development, development scenario studies, and roadmaps, to ensure that the long-term development needs can be met. Rapidly rising revenues for governments, and producers, lead to greater expectations that all oil sands research investments will increase, to maintain and enhance the sustainability of oil sands operations. Given the current shortages in research and producer personnel, and the continuing loss of experienced personnel to retirement, ramping up R&D will be as much, or more, of a challenge as the recent ramping up oil sands construction.

[1] Alberta's Oil Sands 2004 (Updated December, 2005) showed oil sands underlying 140,800 km2 of land with close to 75% still available for exploration and leasing.

2. Background – Current Situation Assessment

The oil sands, in Alberta, are an immense Canadian resource, comparable in volume to resources in Saudi Arabia, and are rapidly gaining international notice and importance. Bitumen production already makes up over 50% of Canada's oil supply, and is attracting billions of dollars in capital investment to support its rapid expansion (see Figure 2.1). Applications for oil sands mining projects already cover much of the resource that is considered to be surface mineable. Deeper thermal in-situ, and cold bitumen production operations are being developed at a comparable pace, in anticipation of the commercial success of a large number of Steam Assisted Gravity Drainage (SAG-D) pilots, and early commercial and commercial stage projects.



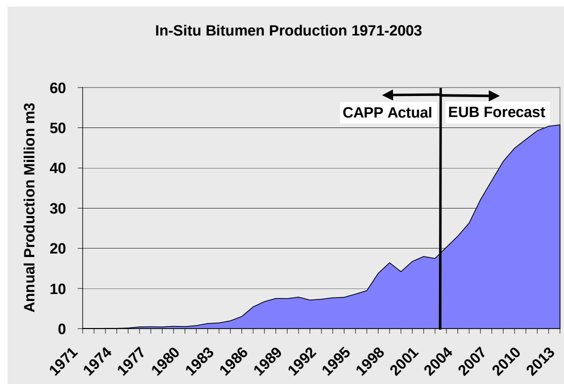


Figure 2.1 – Projected Rapid Growth in Oil sands Production (CAPP/AEUB based on current projects and applications)

While the magnitude and pace of development are impressive, only about 43% of the resource has been assigned any level of recovery, using proven technologies. The remainder of the oil sands deposits, assessed at 0% recovery, are found in deposits that may be considered too deep to surface mine, or too shallow or too geologically uncontained to allow the use of current in-situ recovery methods. In addition to the oil sands, there are bitumen resources in the "Carbonate Triangle" west of Ft. McMurray, small oil sands deposits in Saskatchewan, and more conventional, but potentially recoverable, heavy oil deposits in both provinces.

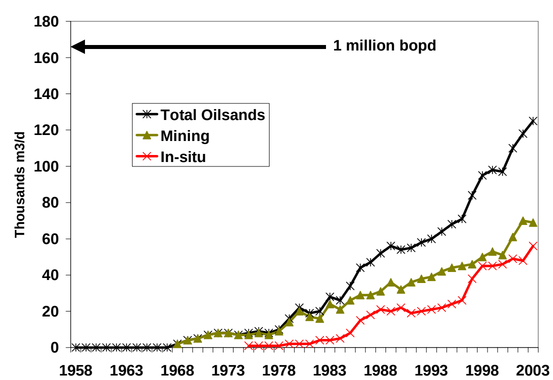


Figure 2.2 – Historic Growth of Oil sands Production – Mining/In-situ Balance (CAPP)

A key challenge will be to determine how these resources might be sustainably developed, without major increases in GHG emissions. Some existing processes might be adapted. However, all of the existing commercial processes are energy, water and emissions intensive, or may require solvents which, in future, may be in short supply. Applying existing methods in lower quality deposits is likely to further increase energy and GHG intensities. Finding alternate, lower intensity processes, will help support heavy oil and bitumen development, while reducing future environmental impacts of production.

Aside from the technology needs themselves, another challenge will be in developing new methods of supporting the necessary research, at a time when all the industry's available capital and human resources are directed at development. While producers and governments, through organizations such as NRCan, AOSTRA, COURSE, AERI, CONRAD and PERD, have invested considerable resources, over the past 30 years, in researching technology for mineable, and deep in-situ oil sands production, research on other deposits is still in its infancy. The on-going effort currently being put on commercializing the mineable and in-situ oil sands will remain the main focus of industry and provincial efforts in the near-term. However, the long-term need for new unconventional heavy oil production technologies, requires that initial research begin soon, so that concepts can be adequately developed, and piloted, before the current oil sands development waves have broken. It is anticipated that whatever technology is used for "inaccessible", low quality heavy oil and bitumen deposits, the energy, GHG and water intensities will be higher, if development is limited to extension of currently used recovery processes. Even for the current commercial oil sands processes, there is growing concern about cumulative impacts on GHGs, air, land, water and human resources required for further development.

Development and implementation of the current recovery processes have demonstrated that RD&D is long-term, and it will take at least 15-30 years before a new technology, proposed today, will be suitably proven to justify multi-billion dollar investments to develop any of these resources. Currently announced oil sands projects account for almost all the mineable oil sands, and much of the highest quality in-situ resources. Forecast producing rates on the order of just under 800 thousand m^3/d (5 million barrels per day) are much higher than past peak oil rates. Therefore, even larger reserves are not guaranteed to last a long time. While there is some optimism that energy conservation efforts will reduce future energy demands in North America, the rapid growth of demand in developing regions will mean that hydrocarbons will experience growing demands for new production sources. Much of that production may come from Canadian bitumen deposits.

To assess future R&D directions for expansion of the heavy oil and bitumen resources, it is first necessary to set the stage by outlining the current state of the resource. The following section outlines: a) the relative size of the various deposits, in comparison to conventional light and heavy resources, b) a number of sustainability factors that must be included in the assessment of potential technology directions, and c) what actions have already been undertaken to support R&D and lay out the technological requirements to move development forward.

2.1. Heavy Oil and Bitumen Resources

Terminology - When discussing fossil resources, the terminology used by the AEUB will be the used in this report.

- **Volume in place** is the quantity of resources calculated or interpreted to exist in a reservoir. These volumes are specifically proven by drilling, testing or production. They also include the portion of contiguous resources that are interpreted to exist from geological, geophysical or similar information with reasonable certainty.
- **Established reserves** are the fraction of volume in place that is recoverable on the basis of current technology, and present, or anticipated, economic conditions. Established reserves are calculated by applying a recovery factor to volume in place.
- **Initial volume in place and initial established reserves** are the quantities before any volume has been produced from the reservoir.
- **Remaining volume in place and remaining established reserves** are the initial quantities less cumulative production.

Volume In Place and Established Reserves of Alberta Oil Resources

The Alberta oil industry was developed by exploiting conventional light and medium oil. Later, technology allowed the economic recovery of conventional heavy oil, which is now a mature segment of the industry. It is only in recent years that oil sands were considered a significant commercial opportunity, firstly with surface mining in the mid-1970's, and later with thermal in situ developments in the mid-1980's.

Table 2.1 - Alberta Oil Resources Volume In Place and Reserves

	Initial Volume In Place (billion m^3)	Cumulative Production (billion m^3)	Remaining Established Reserves (billion m^3)	2004 Annual Production (billion m^3)	Currently Not Recoverable with Commercial Technologies (billion m^3)	Percent Not Recoverable (billion m^3)	Reserve Index (years)
Bitumen	269.95	0.73	27.66	0.063	241.55	89.5%	436
Conventional Light Medium Oil	7.86	2.11	0.18	0.023	5.57	70.9%	8
Conventional Heavy Oil	2.14	0.31	0.07	0.012	1.76	82.3%	6

Source: (Alberta Energy and Utilities Board 2004)

Table 2.1 presents details of volume in place, and reserves for bitumen, conventional light and medium oil, and conventional heavy oil. Bitumen has the largest quantities of volume in place, and remaining established reserves, followed by conventional light and medium oil, and lastly by conventional heavy oil. Alberta's history is reflected in the relatively high cumulative production of conventional light and medium oil, which at the present time far exceeds cumulative production for either bitumen or conventional heavy oil. This must be contrasted however with the reserve index, which indicates how long the remaining reserves will last at current production rates. The most recent annual production information results in reserve index calculations of 8 and 6 years for conventional light/medium oil and for conventional heavy oil respectively, on the basis of their remaining established reserves. By contrast, the reserve index for bitumen is 436 years when using the same methodology.

A considerable number of new oil sands projects are presently being constructed, and will result in a significant increase in bitumen production in the near future. If bitumen production increases to the level of 500 thousand m^3/d (3 million barrels per day), the reserve index would be reduced to 159 years, on the basis of the current estimate for remaining established reserves. A bitumen production rate of 800 thousand m^3/d (5 million barrels per day), as envisioned in the Alberta Chamber of Resources, Oil Sands Technology Roadmap, would further decrease the reserve index to a lower, but still impressive, 95 years.

While the above assessment is useful in providing an estimate of potential recoverable resources, the reality is that there is considerable variability in estimates. Table 2.2 provides a more flexible picture of what is recoverable given the uncertainties, with technologies that are in the very early stages of application, and in relatively undefined deposits.

Initial In-Place Volume (Assumed Recoverable)		
	billion m^3	**% Total**
Surface mining (70-80% recovery??)	**9.4 (6.6-7.5?)**	**3.5**
CSS and SAGD (10-30% recovery??)	**83.5 (8.4-25?)**	**31**
Primary Cold (5-10%??)	**24 (1.2-2.4?)**	**9**
Total	**117 (16-35?)**	**43 (14%)**

At 0.5 million m^3/d (3 million bopd) – 80-190 years
At 0.8 million m^3/d (5 million bopd) – 50-115 years
At 1.3 million m^3/d (8 million bopd) – 30-72 years

Table 2.2 – Potential Recovery Factor Ranges, Resulting Reserves and Resource Life Assuming a Range of Production Rates from "Accessible" Resources

It is currently hard to imagine oil sands production reaching 8 million bpd, and even with maximum possible growth, it would take decades to reach that level of production. Therefore, somewhere between 50-190 years is a reasonable range of reserve life, assuming that there are not any better opportunities in the currently "inaccessible" deposits.

Figures 2.3 to 2.6 provide more details about some of the key numbers presented in Table 2.1. Figure 2.3 compares conventional light and medium oil to conventional heavy oil. Conventional light and medium oil is double the size of conventional heavy oil as measured by the annual level of production and by remaining established reserves.

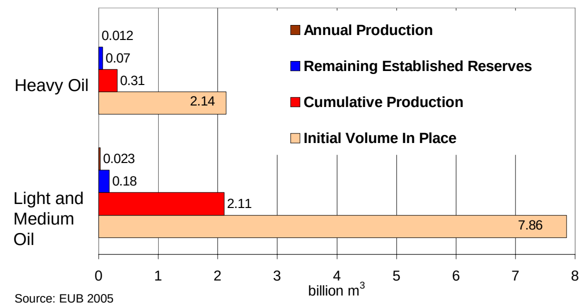
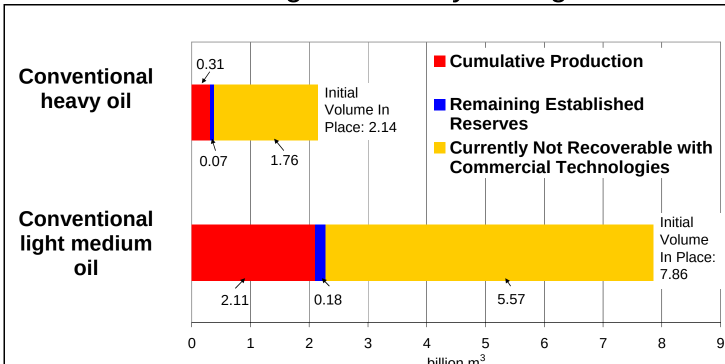


Figure 2.3 – Alberta Conventional Oil Resources

Figure 2.4 demonstrates the opportunity presented by conventional oil. As clearly indicated in the 2003 PTAC report entitled "Spudding Innovation", there is a relatively large quantity of oil that will remain in the ground after all conventional production ceases, given currently utilized technologies. These amounts are shown on Figure 2.4, as the section labeled "Currently not recoverable with commercial technologies". Without innovation, continued use of current technologies will leave in the ground 71% of the initial volume in place of conventional light and medium oil, and 82% of the initial volume in place of conventional heavy oil.

One of the key recommendations of Spudding Innovation was the creation of a detailed business case for increased oil and gas recovery through R&D, demonstration and commercialization. The proposed goal, for conventional oil, was additional recoverable reserves of 800 million m^3 (5 billion barrels) by 2015, attributable to new R&D. As discussed in "Spudding Innovation", a 1% improvement in conventional oil recovery is equivalent to about 600 million barrels of oil, or about $22 billion in production revenues and $2.2 billion in royalties.



Source: (National Energy Board 2004; Alberta Energy and Utilities Board 2005)

Figure 2.4 – Alberta Conventional Oil Resources – Currently Unrecoverable Volume In Place

In response to Spudding Innovation, industry and AERI have funded a $840,000 PTAC business case project, which is due to report in 2006. In addition, the Alberta Department of Energy announced a $200 million, Innovative Energy Technologies Program (IETP), which supports the demonstration of new oil and gas technologies.

While the opportunity to expand the conventional oil resource is being acted upon, bitumen offers a similar, if not more compelling opportunity.

Figure 2.5 shows key numbers for oil sands. It is immediately apparent that oil sands are a recent, but highly promising sector. Annual production and cumulative production are very small, as compared to remaining established reserves, and initial volume in place.

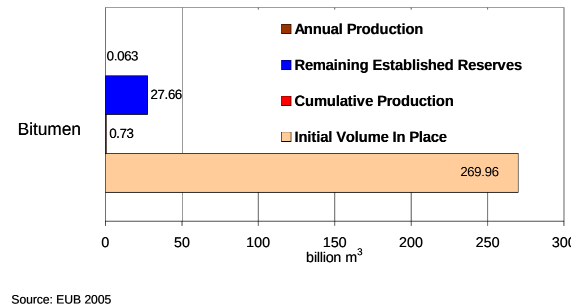


Figure 2.5 – Alberta Bitumen Resources

Figure 2.6 presents the opportunity offered by oil sands, and compares it to the opportunity described earlier for conventional oil. Without innovation, the continued use of current technologies will leave behind 89% of bitumen volume in place, after all recovery activities cease. The amount of bitumen that is currently not commercially recoverable is 241 billion m³. This amount is over 30 times larger than the unrecoverable volumes of conventional light, medium and heavy oil combined. Therefore, oil sands not only present a substantial economic opportunity in the near-term using existing commercial technologies, but also a larger opportunity in the long term.

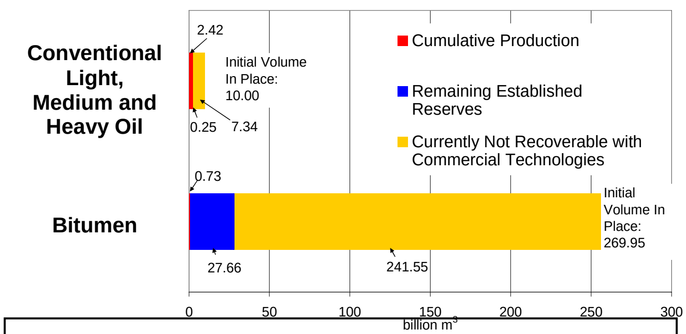


Figure 2.6 – Alberta Bitumen Resources – Currently Unrecoverable Volume In Place (Source Alberta Energy and Utilities Board 2005)

2.2. Alberta Bitumen Resources

Alberta's bitumen resources are not uniform. There are major differences between regions and between geological zones. On the one hand, some bitumen deposits are highly attractive while other deposits are not, when using present technology. Therefore, they are left undeveloped. Rich and thick oil sands form the foundation for the current build-up of oil sands projects in the Athabasca region. Recovery factors for high-quality reservoirs can reach as high as 60% for in situ and 90% for surface mining. By contrast, some very large bitumen deposits have recovery factors of zero.

In this section, an overview of Alberta's bitumen resources is provided from the point of view of compatibility with current commercial recovery technologies.

As indicated in Table 2.3, on the following page, bitumen deposits are found in three regions of Alberta: Athabasca, Cold Lake and Peace River. Athabasca is by far the largest region with 80% of bitumen volume in place. Athabasca is also the only region where surface mineable deposits are found. The second largest region is Cold Lake. Peace River is the smallest and least developed oil sands region.

For the purpose of this study, the deposits exploitable with existing commercial technologies were classified under one of three categories:

- Economically recoverable by Steam-Assisted Gravity Drainage (SAGD), Cyclic Steam Stimulation (CSS) or equivalent thermal technology;
- Economically recoverable by surface mining; and,
- Capable of cold primary production.

As shown on Table 2.3, on the next page, deposits recoverable with existing commercial technologies amount to 43% of the Alberta oil sand resource. The balance, or 57%, is currently deemed not recoverable with existing commercial technologies and is assigned a recovery factor of zero. The two largest categories of deposits with no recovery factor are bitumen in carbonate formations and thin oil sands. Together, they represent 50% of the total Alberta bitumen resource. The relative importance of deposits deemed not recoverable with existing commercial technologies is shown on Figure 2.7.

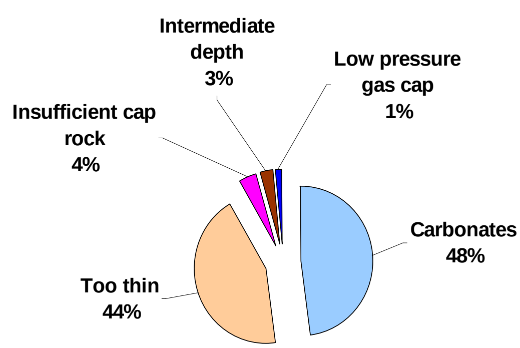


Figure 2.7 – Alberta Bitumen Resources with No Recovery Factor

Table 2.3 - Alberta Bitumen Deposits – In-place Volumes (billion m^3)					
Deposit Type	**Athabasca**	**Cold Lake**	**Peace River**	**Total**	**Percent**
Deposits Accessible to Existing Commercial Technologies					
Economically recoverable by SAGD, CSS or equivalent commercial thermal technologies	66.8	7.5	8.6	82.9	30.7%
Economically recoverable by surface mining	9.4	0.0	0.0	9.4	3.5%
Capable of cold primary production	2.0	21.0	0.06	23.1	8.6%
Total - Accessible Deposits	78.2	28.5	8.7	115.4	42.8%
Deposits with No Recovery Factor					
Bitumen in carbonate formations	60.8	0.0	10.3	71.1	26.4%
Too thin for commercial thermal processes	60.4	3.4	1.3	65.1	24.1%
Deposits with insufficient cap rock, shale or clay barrier	5.8	0.0	0.0	5.8	2.1%
Too deep for surface mining but too shallow for SAGD	4.4	0.0	0.0	4.4	1.6%
Deposits in communication with low pressure gas cap (e.g.: Liege, Ells, Tar and Saleski)	2.2	0.0	0.0	2.2	0.8%
Others	5.7	0	0.2	5.9	2.2%
Total - Deposits with No Recovery Factor	139.3	3.4	11.8	154.5	57.2%
Total - All Deposits	217.5	31.9	20.5	269.9	100.0%

While each category will be discussed in detail later in this report, they will be briefly described in this section by way of introduction.

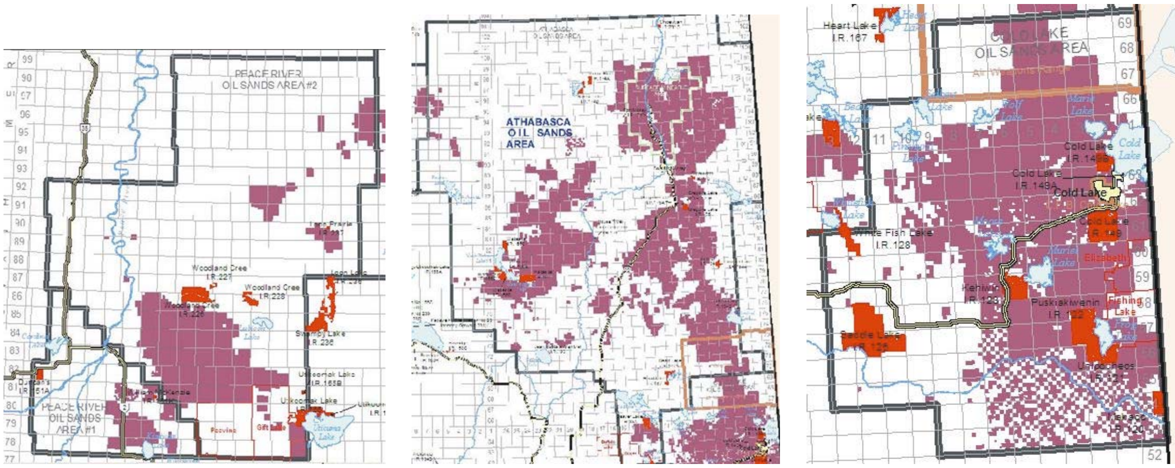


Figure 2.8 - Maps of Oil sands Areas – Peace River, Athabasca, Cold Lake[2]

2.2.1. Deposits Recoverable by SAGD, CSS or Equivalent Thermal Technology

The largest category of deposits that are recoverable with current commercial technologies is the category associated with thermal technologies such as SAG-D and Cyclic Steam Stimulation (CSS). This category is generally composed of thick, rich channel sands, and represents 83.5 billion m^3 or 31% of the total oil sand resource.

2.2.2. Surface Mineable Oil Sands

Historically, oil sands development started in Athabasca with surface mining. Mineable bitumen deposits are located near the surface and are recoverable by open-pit mining techniques. While the surface mineable area of Athabasca holds a gross amount of approximately 10% of the oil sands resource, the quantity that is actually economically recoverable by surface mining is only 9.4 billion m^3 or 3.5% of the total resource.

2.2.3. Bitumen in Carbonate Formations

While the overall bitumen resource area in Alberta is commonly called "oil sands", 71.1 billion m^3 or 26% of Alberta's bitumen resources are not held in sand formations, but in carbonate formations. There are four recognized bitumen bearing carbonates formations in Alberta, with the most significant being the Grosmont Formation. The Grosmont is a large, shallow marine carbonate formation with four recognizable units. The best reservoir consists of a dual porosity dolostone with high porosities and good bitumen saturations. The porosity system includes vugs, up to 10 cm in size, and inter-crystalline porosity. Fracturing can also be present. The Grosmont presents considerable challenges for drilling, completions and steam containment. Three production pilots were conducted in the 1980s. However, they had mixed success, and efforts to recover bitumen from the Grosmont Formation were subsequently abandoned.

[2] Source for oil sands maps www.energy.gov.ab.ca/2825.asp . Purple areas under agreement; white areas within area boundaries are not under agreement at this time.

No other bitumen extraction pilots have been conducted on any of the other carbonate formations. As a result, the recovery factor for bitumen in carbonates at present is zero.

2.2.4. Unconfined Oil Sands

Current commercial thermal in-situ technologies, such as SAGD and CSS, inject steam into the deposit. Steam must remain inside the deposit for the process to work and to allow economic recoveries. Some deposits lack the geological attributes necessary for steam containment.

Deposits with Insufficient Cap Rock, Shale or Clay Barrier: Some deposits, mostly in Athabasca, lack sufficient overlying rock, shale or clay to act as an effective barrier to steam movement. In aggregate, deposits with insufficient cap rock account for 5.8 billion m^3 or 2.1% of the total bitumen resource.

Deposits Too Deep for Surface Mining but Too Shallow for SAGD: Intermediate zone oil sands are deposits that are too deep for surface mining but too shallow for SAGD. For the purpose of this study, intermediate zone oil sands are defined as oil sands at depths from 40 to 75 m. They represent a resource of 4.4 billion m^3 or 1.6% of the total oil sands resource.

Deposits in Communication with Low Pressure Gas Caps: The industry and the AEUB have spent considerable time and effort studying shallow gas reservoirs overlaying bitumen deposits. The issue is that the bitumen zone is in communication with the overlying gas zone and, therefore, steam injected into the bitumen zone could escape into the gas zone. This may severely reduce the effectiveness of steam injection, or even potentially prevent bitumen recovery. Bitumen deposits in communication with shallow gas reservoirs are mainly located in Athabasca, and account for 2.2 billion m^3 of bitumen or 0.8% of the total bitumen resource.

2.2.5. Thin Oil Sands

Thin oil sands are overlying oil sand intervals separated from other oil sands by laterally extensive shales. These shales impede or prevent the vertical flow of fluids, effectively sub-dividing the deposit. In addition, oil sands can occur near the edges of the deposits, where the total thickness of the deposit is reduced. Thick bitumen deposits are much more attractive for SAGD operators because they offer improved economics and lower environmental footprints. The exact thickness, at which deposits become too thin for recovery by SAGD, is a subject of uncertainty. Current commercial SAGD projects have been justified for deposits offering at least 25 m of thickness. However, for the purpose of this study, it was considered that 10 m should be the minimum thickness for SAGD. Thin oil sands represent a considerable resource even at a conservative cutoff of 10 m. The volume in place for thin oil sands is 65.1 billion m^3 or 24% of the total bitumen resource. Over 90% of thin oil sands are located in the Athabasca region.

2.2.6. Deposits Capable of Cold Primary Production

Bitumen viscosity is not uniform across the Alberta oil sands. In some deposits, bitumen viscosity is low enough to allow cold primary production, even in deposits that would be too thin to consider for existing thermal recovery, or alternative processes. The main method of production from these deposits is by allowing sand to flow into the wells, driven by a tendency of the bitumen to foam when pressure is reduced. This method, sometimes referred to as Cold Heavy Oil Production with Sand (CHOPS), may produce over 25% sand, by volume, with the bitumen, and result in over 1,000 m^3 of sand being produced from each well. The downside of cold primary production is that the bitumen recovery factor is low, in the order of 5%.

2.2.7. Small Surface Deposits

The first oil sand mines were located where the deposits are shallow, thick, rich and laterally continuous over a wide area. These factors favor project economics. With the expansion of interest in the oil sands industry, deposits where the ore bodies are fragmented into small surface deposits are now being explored. The AEUB estimates the size of small fragmented surface mineable oil sands at 10% of the surface mineable volume, or approximately 900 million m^3 or 0.3% of the total oil sands resource.

Small surface bitumen deposits have also been observed in two areas of Saskatchewan: the Clearwater valley, which is east of Athabasca; and the Peter Pond and Churchill Lake area, which is north east of Cold Lake. The information is found in geological reports dating back to 1954 and 1978. The quantities of oil sands were deemed uneconomic at the time, despite the fact that the assessment was based on a relatively small amount of data.

2.2.8. Oil Sands Deposits Under Tailings Ponds

Surface mining currently requires that areas be set aside for tailings ponds. The area now covered by tailing ponds is estimated at 20,000 hectares. This area is bound to continue to increase with the number of new mines that are being constructed.

While efforts are made to locate tailings ponds over poor quality oil sands, this is not always possible. The AEUB estimates the size of surface mineable oil sands sterilized by all surface facilities, including tailings ponds, at 10% of the surface mineable volume. Therefore, less than 900 million m^3 or 0.3% of the total oil sands resource would be under tailings ponds. As indicated above, only a fraction of this volume would be considered attractive oil sands.

2.3. Limits of Existing Technologies

The starting point for determining the limits of current commercial technologies, for this study, was to utilize the same factors used by the AEUB for reserve calculations. Relevant AEUB parameters are summarized on Table 2.4. While the AEUB has attempted to indicate limits on what existing recovery methods can achieve, many of those limits have still not been demonstrated. In this section, a discussion on how these parameters were applied is provided for the two major technologies used in Athabasca: surface mining and SAGD.

	Depth (m)	Thickness (m)	Bitumen (mass %)
Surface mining	< 40	> 3	> 7
Thermal	> 50	> 10?	> 6
Cold primary production	> 75?	> 3	> 6

Table 2.4 – Parameters Used by AEUB to Designate Accessible Resources (Limits shown with a "?" have the greatest uncertainty)

2.3.1. Surface Mineable Oil Sands

Bitumen is mined from the surface with open-pit mining techniques. About two tonnes of oil sands must be dug up, moved and processed to produce one barrel of oil. Technology developments over the past decades have been instrumental in reducing costs and making oil sands recovery economic. This has enabled part of the current phase of commercial developments. For example, oil sands operations near Fort McMurray use the world's largest trucks and shovels to economically recover bitumen.

The depth to which surface mining is economic depends on several factors, in particular on the economic strip ratio, which is defined as the ratio of overburden material to recoverable ore. A rule of thumb is a 1:1 ratio of overburden to deposit thickness is economic at an oil mass percent of 11%. In reality, there are seven to eight factors that need to be considered, in order to determine the economics of oil sands recovery by surface mining.

It is currently economic to mine to a depth of 40-50 meters, in three benches of approximately 15 m each. For exceptionally rich deposits, it is possible to add another bench or another 15 m, but this would be exceptional. For the purpose of this study, surface mining was deemed to be economic to a depth of 40 m on a deposit wide basis, thereby matching the approach adopted by the AEUB.

2.3.2. Deposits Recoverable by SAGD or Equivalent Thermal Technology

Two major factors were considered to limit the deployment of SAGD: a) deposit thickness and b) depth.

Thickness

In Athabasca, oil sand deposits are thicker in the central region, but they thin out in areas surrounding the central thick channel oil sands. Thick bitumen deposits are more attractive for SAGD operators because they offer improved economics and lower environmental footprints. The key reasons are as follows:

- Thicker deposits contain more oil over the producing horizontal well.
- The maximum width of the steam chamber is determined by its maximum height because a minimum gravity gradient must be maintained. In SAGD, gravity is the drive mechanism. Thicker deposits result in a wider steam chamber and therefore increased well spacings. This decreases capital costs and environmental footprint.
- Thicker deposits will lose less heat to the over burden.

For the purpose of this study, it was considered that 10 m should be the minimum thickness for SAGD, even though commercial projects have been justified based on thicknesses of at least 25 m. Two reasons support this conservative approach:

First, SAGD is a relatively new technology. Continuous technology improvements should allow SAGD to eventually become economic at thicknesses lower than today's limit.

Second, once thick deposits are exploited, SAGD operators may find it economic to continue using existing surface facilities for thin zones. Surface facilities are required to produce steam and to handle produced liquids from deposits. Using the same surface infrastructure for the surrounding thinner deposits, would avoid significant costs, and could make recovery of thinner deposits economic.

Depth

SAGD is more attractive with greater overburden thickness, because this enables the process to operate at higher pressures and temperatures. These more aggressive steaming conditions increase bitumen production rates. Higher temperatures create a greater reduction in bitumen viscosity, and result in higher bitumen production rates, than at lower temperatures. However, steaming at lower temperatures is more efficient because of the reduced thermal gradient between the over and under burden. The net effect, however, is a higher total cost for low pressure SAGD. The minimum depth for SAGD is currently subject to technical investigations. Low pressure SAGD is currently being piloted with steam alone or with added solvent mixtures in order to extend the applicability of the process.

2.3.3. Deposits Capable of Cold Primary Production

As noted above, some bitumen deposits allow cold primary production. The downside of cold primary production is that the recovery factor is low, in the order of 5% for bitumen and may damage the reservoir for subsequent follow up production. Therefore, a very significant quantity of bitumen is left in the ground. The recovery process for cold primary production is still poorly understood and areas amenable to this type of production are being rapidly depleted.

2.4. Economic Factors

In assessing the need for expansion of technology options for Canada’s bitumen resource, some consideration must be made of the potential future demands on the resource. The pace of development of the oil sands will be driven by a number of economic factors, many of which are external to Canada. On a global level, overall world supply/demand balance for liquid hydrocarbons will be a major economic driver, and is greatly affected by global political, economic and conservation efforts. As was indicated in the previous section, the life of the "accessible" and currently recoverable bitumen resource will depend on the rate at which it is produced.

Upgrading and Pipeline Capacity

While the Canadian bitumen resource is immense, the global demand for raw bitumen is limited, as most refineries cannot process it, and it is difficult to transport. Energy and capital intensive upgrading is required at the recovery site, or at the refinery, to increase its quality to the level of synthetic crude oil. Currently it is much easier to bring on additional bitumen production capacity, than it is to add upgrading or transportation capacity to allow the product to enter global markets. This disparity creates an on-going supply surplus of raw bitumen in Alberta that further depress heavy oil and bitumen prices, even while world oil prices experience wide fluctuations. Figure 2.9 illustrates the disadvantage heavy oil and bitumen producers experience because of the inherent lower quality of bitumen, and when the supply of raw material exceeds the capacity of upgrading and pipeline capacity. These high differentials in price between raw and upgraded products drive development of additional upgrading and pipeline capacities. Existing royalty breaks from the provincial government encourage development of production; however, once project payout is achieved, the royalties collected are usually on a lower valued product, than would be the case if a better supply/demand balance could be maintained.

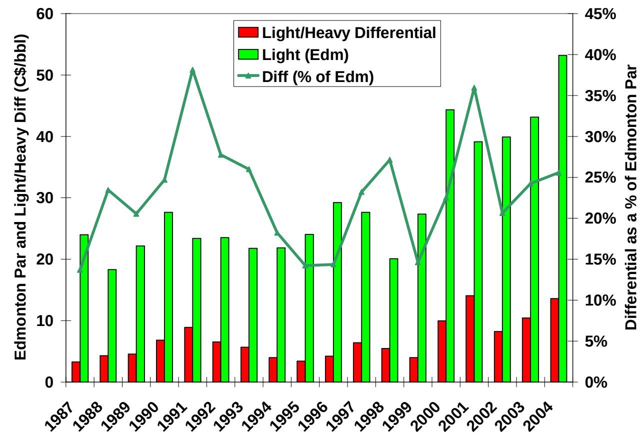


Figure 2.9 – Economic Disadvantage of Crude Bitumen and Heavy Oil vs. Light Crude

Capital Costs - The pace of growth also has a major impact on the capital costs associated with bitumen developments. At the current high rate of growth, costs continue to escalate across the sector, as well as in other sectors in the province, which compete for the same manpower and materials. Even with royalty relief to help cover higher capital investments, and despite higher world oil prices, the return on capital is being eroded for bitumen producers. If global oil prices begin to show weakness, or raw production volumes advance too quickly, returns on capital could quickly become unattractive to investors. Capital costs are an issue even with development of the highest quality of oil sands resources. As the quality of the remaining oil sands resources drops, capital intensity is likely to continue to increase.

2.5. Environmental Factors

Environmental concerns continue to grow along with the pace of oil sands development. Concerns cover a broad range of issues both short and long-term. Current production from mining and in-situ thermal operations is highly concentrated as it is focused on the thickest and richest deposits, which directionally reduces the environmental footprint per unit of bitumen production. As development moves into smaller and less concentrated deposits, the environmental impacts will spread and cover ever larger areas of the province.

Water – Currently, the largest concern in the bitumen development regions is focused on water use and reuse, as bitumen production can be much more fresh water intensive than other oil production operations (Figure 2.10[3]). While the northern part of Alberta is not considered water short, the Athabasca River experiences low winter flow, and surface water flow is believed to be closely connected to groundwater flow[4]. In bitumen production, water make-up intensity increases with the decreasing quality of the resource, which also drives energy consumption for water treatment and management. Large tailings ponds from surface extraction of bitumen from oil sands are a major concern for the long-term protection of the Athabasca River and downstream water users. For in-situ bitumen areas, the main surface or ground water quality concern is with potential contamination by produced brine, chemicals used for water treatment and heavy metals made mobile through thermal processes.

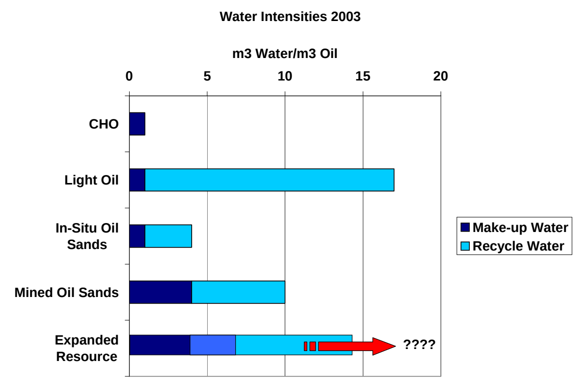


Figure 2.10 – Water Intensities for Various Oil Resources

Air – Air emissions from current operations are composed of GHG emissions from a global perspective, sulphur emissions (sulphur dioxide) and heavy metals from a regional perspective when coke or bitumen are used as fuel, and Volatile Organic Compounds (VOCs) causing odors and potential worker impact on a local level. High natural gas prices and projected supply shortages are resulting in a greater focus on bitumen or coke combustion for fuel. Some producers are using stack clean-up techniques; however, total emissions will grow significantly as production volumes increase.

Land – The degree and extent of land disturbance is greatly impacted by the type of bitumen development, the quality/concentration of the resource per unit area, and the type of recovery process used. Surface mining has the greatest impact as over 100% of the land surface over the bitumen reservoir is disturbed or removed and must be replaced later. Shallow in-situ developments are likely to cause some net surface subsidence, while deeper operations will likely have less net impact. The

[3] Volumes in the graph exclude water consumed for power generation and natural gas voidage replacement.
[4] Peachey, Bruce – Strategic Needs for Energy Related Water Use Technologies – www.aeri.ab.ca

concentration of in-situ bitumen, in a given deposit, impacts the spacing and distribution of surface access and production facilities, which may disturb 10-20% of the active development area.

Ecosystems - As most of the current and future bitumen production areas are in relatively undeveloped, and difficult to access regions, the wetland systems affected have not been extensively researched. Some unique ecosystems, such as the Kearl Lake dune areas, have been identified and the intent is to protect them from significant development. Similarly, the ecosystems of the major rivers are targeted for protection, even though smaller tributaries might be totally disrupted by mining operations.

2.6. Energy and GHG Intensity Factors

A major difference between bitumen and conventional oil and gas developments is in the energy intensity of bitumen operations, which leads to a corresponding higher greenhouse gas (GHG) intensity.

Energy Intensity and Quality – As shown in Figure 2.11[5] the net energy intensity of bitumen operations is 2-3 times that of conventional heavy oil (CHO), or light oil operations. As energy intensity increases, the net energy output decreases. The growing use of cogeneration of heat and power in bitumen operations is a major step in improving the overall energy efficiency of bitumen production. These gains are recognized by taking into account energy losses from stand alone generation. This impact is shown by the lower green bars in Figure 2.11, which add estimates of the relative amount of electrical power used in each sector to the energy intensities from direct fuel use.

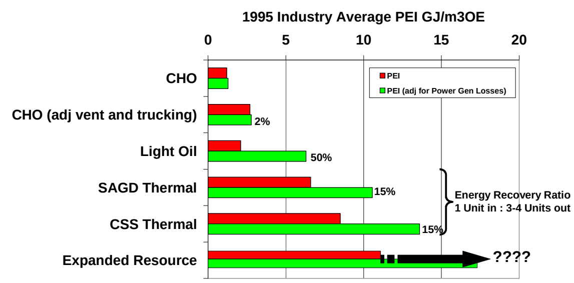


Figure 2.11 – Energy Intensities of Hydrocarbon Resource Extraction

GHG Intensity – Figure 2.12 illustrates the impact of the higher energy intensities of bitumen operations on GHG emissions from bitumen production. As most conventional heavy oil and bitumen must be upgraded, the upgrading Production Carbon Intensity (PCI) in the figure must be added to the extraction emissions from those sectors. Upgrading carbon intensity is primarily driven by the upgrading

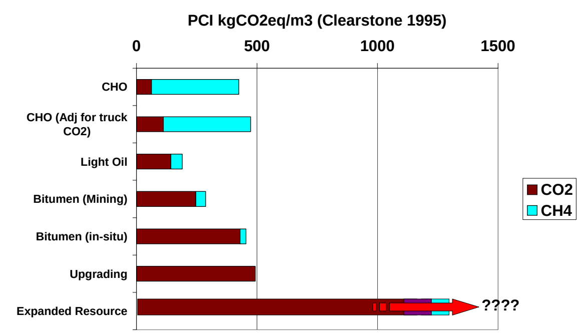


Figure 2.12 – GHG Intensities of Hydrocarbon Resource Extraction

[5] Industry Average "Production Energy Intensity" (PEI) is based on the Canadian Association of Petroleum Producers reporting guide for the Voluntary Challenge Registry. Adjustments to account for heavy oil trucking and energy losses at stand alone power generation facilities were estimated by New Paradigm Engineering Ltd, to be more consistent with CAPP's GHG intensity indicators, which include GHG emissions from power generation.

process, and the desired quality of the end products. However, the extraction carbon intensities will increase with lower quality bitumen resources.

2.7. Security and Societal Factors

Development of such an enormous resource generates significant security of supply and societal benefits. However, many of those benefits must be balanced against potential risks and uncertainties.

Near-Term Risks – In the near-term, a potential risk is that some major developments may be moving ahead of technology, especially in shallow oil sands areas, where there has not be an a long history of commercial production. The Cold Lake area has been under commercial production since 1986 and was built on experience gained from 10-20 years of pilot operations in the area, at depths in the 400-500m range. In shallower deposits, the oil sands are closer to the surface, and the bitumen is held in place by its high density and viscosity, rather than the presence of any caprock. The lack of experience in shallow formations increases the risk that unexpected problems, or production issues, may arise as operations progress, resulting in lower than expected recoveries.

Human Resources – Development of bitumen capacity is very manpower intensive in some skill areas, such as construction trades, heavy equipment manufacturing and transportation. However, once the facilities are in place, the demand shifts to significantly different skill sets and human resource requirements. Large, transient, camp-based labour forces will be replaced with a smaller, resident, permanent workforce that will place greater demands on local medical, school and recreational resources.

Impacts of Unknowns – Other unknowns, which could impact bitumen production, are uncertainties related to the pace of demand for natural resources and infrastructure outside of the main development areas. Potentially, limits could exist on water supplies or disposal zones, and international impacts due to fluctuations in global supply and demand of construction materials. The higher the rate of bitumen production development, the greater will be the exposure to potential short-term changes in hydrocarbon demand, and the ability of public infrastructure to keep up with demand.

2.8. R&D Support

Currently, the oil sands sector is mainly focusing on rapid expansion of production, with essentially all sales revenues being allocated to constant production growth. The growth is fueled by rising international oil prices, and is based on mining, extraction and in-situ technologies developed in the 1970's, with the aid of the Alberta Oil Sands Technology and Research Authority (AOSTRA) and corporate research organizations. Over the last two decades, R&D expenditures have dropped to extremely low levels, given the size of the resource and the level of the investments now being made in the sector.

Government/Institutional – Currently, most government and institutional research support is provided through university research (NSERC chairs at U of Alberta and U of Calgary and other grants), the Alberta Research Council (ARC), NRCan's

Research Centre in Devon, Alberta, and other centers. The main focus of the research is on collaborative efforts, to address chronic environmental or basic process problems of common interest to producers with existing operations. A recent assessment, by Alberta Department of Energy (ADOE) shows that total R&D spending by governments for oil sands is on the order of $23 million per year (about 6.5% of the average royalties received for oil sands production between 1997 and 2003). Meanwhile, expenditures on development and revenues for producers each reached $10-12 billion/yr in 2003[6].

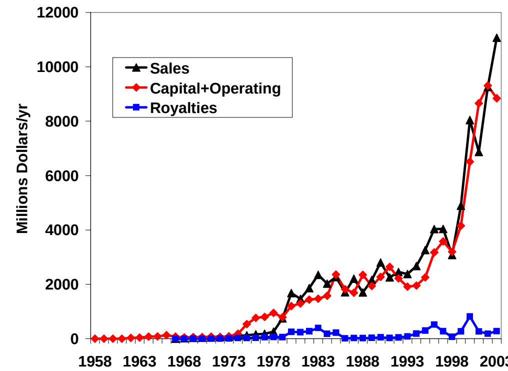


Figure 2.13 – Sales Revenues vs. Expenditures and Royalties in the Oil

Industry – Most producers have relatively little in-house support for laboratory or theoretical R&D in Canada, and any research is conducted in corporate labs in the U.S. or Europe. Research conducted directly by producers is normally focused on development of competitive technologies such as upgrading, field-testing of novel recovery processes, or asset specific investigations such as pre-commercial demonstration pilots. ADOE is currently surveying producers, and other information sources, to attempt to estimate the level of R&D expenditures on oil sands technology by the producers in the oil sands sector. R&D by service and supply companies is mainly focused on enhancing or adapting existing, off-the-shelf technologies for use in oil sands operations.

2.9. Other Previous Roadmaps and Studies

Over the past 10 years, a number of R&D roadmaps or studies have been completed to address the needs of the hydrocarbon industry in Canada. The main findings of these key "founding" documents, for the current study, have been summarized and provided in Appendix C1. Generally these roadmaps have focused on the more immediate R&D needs of the producers, or on work needed to allow them to move towards commercial oil sands development, rather than longer-term directions, which are the intent of the current high-level roadmap.

[6] "CAPPStatistical Handbook for Canada's Upstream Petroleum Industry" Expenditures and Revenues Tables for Oil sands.

3. Phase I- Objectives and Development Process

3.1. Objectives of the Study

This study was intended as an initial broad-based investigation of "Unconventional" or "Inaccessible" Bitumen and Heavy Oil deposits, with the general objectives of:

- Assessing bitumen and heavy oil deposits including: a) Alberta's Carbonate Triangle, b) intermediate zone oil sands, c) small surface mineable deposits, d) oil sands under tailings, and e) primary production remaining in place;
- Building on previous roadmap efforts to avoid duplication of effort;
- Stimulating interest in considering the potential of new deposits;
- Motivating long-term R&D funding and activity to allow the development of new production options, which might be more sustainable, and have lower GHG intensities, than existing processes;
- Encouraging long-term thinking about R&D needs and strategies; and,
- Identifying some potentially new, or revived, technology directions for R&D, especially those that would have potential to reduce GHG emissions, while allowing sustainable development.

3.2. Areas of Focus

The key areas of focus, based on an initial review of previous roadmaps, literature search and interviews, were determined to be:

- **Resource Base** – "Unconventional" or "Inaccessible" resources currently assigned 0% recoverable reserves and not under active development. The definition was slightly modified from the original proposal mainly to recognize two subsets of oil sands resources categorized as "Thin Oil Sands" and "Unconfined Oil Sands". This change was made as many "Intermediate" zones can already be produced if they are thick and contained. Also "Primary" cold production deposits have been included since recoveries, while not zero, are very low.
- **Long-Term Focus** – to meet needs up to 30 years in the future, although, preferably with potential to also enhance the near-term sustainability, and to reduce GHG emissions from other operations. This recognizes that R&D on truly new processes would take at least 20-30 years to develop to the stage that they could be applied on a large commercial project.
- **Technology Areas** – identified to investigate were: a) Sub-surface construction methods to change the reservoir environment to allow production; b) Use of low cost materials at hand, such as sulphur, CO2, coke, water, tailings, and limestone, by incorporating them into new recovery methods; c) Small, compact, and/or portable processes, to reduce capital and environmental footprints; d) In-situ reactors or processing to minimize energy intensive materials handling; e) New methods of accessing resource over and through

muskeg areas, and glacial till overburden; and f) Environmental assessments in new development areas.

- **Policy/Development** – would look at: a) Potential synergies between deposits to maximize recovery and minimize undesirable impacts; b) Infrastructure development strategies to make best use of existing and orderly development of new infrastructure; c) Enhance security of supply and development by spreading the activity between deposits; d) Assess R&D support needs to allow long-term research to proceed.
- **R&D Gaps** – which were identified in earlier roadmap activities, where there were few ideas suggested and little R&D effort underway, which suggests these might be areas that would support both short and long-term needs.

3.3. Development Process

The project had a very short time line for completion. Work started in November, 2005 with development of initial target areas for literature search and interviews. A PTAC Steering Committee, with broad representation of producers, governments and academics, was established to provide overall direction and input. In January and February, a series of six working group sessions were held in Calgary and Edmonton, with four focused on technology, and two focused on sustainability issues resulting from the technology. To expand awareness and discussion of the project, potential options, and suggestions for policy enhancements, a workshop session was held on March 2nd in collaboration with ADOE Oil Sands Business Unit.

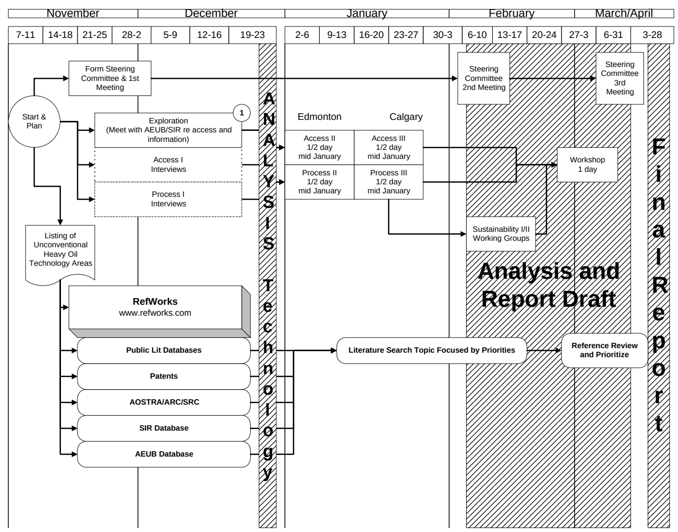


Figure 3.1 – Project Process and Schedule

3.4. Literature Search Output

As part of the project, initial and follow-up literature searches were completed for the project with the results aggregated in an online database, through www.refworks.com . While not all these materials are relevant to the current study, they may be of use to other researchers in preparation for Phase II. Therefore, the intent is to make some version of this material available through PTAC's Knowledge Centre.

3.5. Areas Covered Elsewhere

We have attempted not to duplicate the content of previous roadmaps, which are available and listed in Appendix C2 – Summary of Key Documents.

At the March 2nd workshop, ADOE held two breakout group sessions on policy, which were documented and will serve as a basis for further discussions with producers and other stakeholders.

3.6. Phase II – Detailed R&D Roadmap

Once high level mapping and exploration of ideas has been completed in Phase I of this project, the stage will be set for increased efforts to develop a more detailed plan, for future development of this important resource. PTAC believes that this phase may follow Phase I, within a year or two, after some initial technology exploratory studies have been undertaken to further define research directions identified in Phase I.

4. Identification of R&D Focus Areas

It was decided early in the project to gather information on technologies, which might be a focus of long-term R&D, based on the stages of development, rather than by deposit. This recognizes the fact that technologies may be applicable to a range of deposits and situations. In later sections, these focus areas are discussed in relation to each type of deposit being considered.

The R&D Focus Areas, used in this report, include: Exploration, Access, Processes and Sustainability.

4.1. Exploration

Exploration differentiates between types of depositional environments that will drive technology, resource evaluation and recovery processes. Exploration also identifies base resources that are similar, and currently economic to produce, to provide a comparison with target areas. Finally, it targets primary resource descriptions and analogues. The intent is to track issues, ideas and potential technologies that might be addressed:

- **Resource Characterization Factors** –The key geologic factors that are the most important, such as volumes of oil in place, thickness, depth, oil properties, contaminants, thermodynamic, transport and mechanical properties of deposits, and aspects of the deposit, or over-burden, under-burden properties, which may impact on recovery.
- **Resource Definition Tools** – Methods to get more information to further define the resource characteristics and assess potential processes, such as: opportunistic core and logs, which have already been gathered, and potential new tools for gathering information.
- **Conventional Mineable (Base)** – Defining one recovery starting point, characteristics, opportunities to transfer to other deposits, and potential synergies.
- **Conventional In-situ (Base)** – A starting point for most assessments of most new in-situ resources; needs an understanding of limitations in "accessible" areas to allow extrapolation of technology to new deposits.
- **Conventional Heavy Primary/Cold Production (Base)** – Starting point for anything that follows in a "wormhole filled" reservoir. Understanding wormholes is the assumed to be the starting point for recovering additional resources.
- **Carbonate Heavy Oil** – Impacts of producing bitumen from a solid, vuggy and fractured rock environment, instead of uncemented oil sands.
- **Intermediate Zone Oil Sands** – How much is unrecoverable and why is it felt to be non-recoverable now? Intermediate depth was originally the zone between surface mining and in-situ methods. However, as discussed in section 2, this is now considerably reduced. Therefore, this category has been split into thin oil sands and unconfined oil sands.
- **Uncemented Deep Sands** - After primary Cold Production in the Cold Lake, Athabasca, Peace River, Lloydminster, and Wainwright areas, over 90% of the oil in place remains as unrecoverable.

- **Small Surface Oil Sands Deposits** – Impacts of scaling down conventional mining, to match smaller or thinner surface accessible deposits that cannot be accessed by in-situ methods (e.g. Saskatchewan's Clearwater Valley and Peter Pond Lake areas).
- **Oil Sands Under Tailings Areas** – Accessing quality resources firstly during normal production, and secondly during reclamation or under end pit lakes.

4.2. Access

How you access the deposit from the surface has a large impact on the ultimate recovery of the resource, energy inputs for materials handling, and the quality of what is produced for surface processing.

- **Drilled Wells** – Access from surface may require new drilling methods, target zones, well architectures, development strategies, completion techniques, artificial lift and production monitoring methods.
- **Surface Mining Methods** – Basic options from surface mines such as draglines, bucketwheels, trucks and shovels or dredging.
- **Sub-Surface Mining Methods** – Basic options from underground mining of coal, uranium and other minerals, including: shaft and tunnel, reinforced galleries, remote mining machines, and sub-surface construction methods.
- **Borehole Mining** – Fluid filled mines and extraction cavities, which might involve: hydraulic jets (placer mining techniques); remote boring equipment, remote controlled, self-contained wormhole diggers.
- **Hybrid Methods** – Combining aspects of drilling and mining may offer benefits over considering either/or options. E.g. wells drilled from tunnels, basal limestone mined drainage tunnels with intercepting surface drilled wells, drainage tunnels and boreholes from surface

4.3. Processes

Once the deposit is accessed, there are a growing number of potential methods, which might be applied, either for initial production, or as supplemental recovery processes. Preferred processes might be those that gradually increase the recovery in stages, without adding greatly to GHG emissions or sustainability criteria.

- **Thermal Steam/Water** – Technologies already in commercial use for "accessible" oil sands are assumed to be the base case technologies for comparison to new recovery options. Includes potential water sources, quality of energy injected with the water stream, treatment and disposal methods.
- **Thermal Oxidation** – Methods of using air or oxygen injection, to oxidize part of the resource to produce steam and other combustion products, to enhance recovery of the remainder of the resource. Technologies to address: oxygen sources, location of combustion, performance in the reservoir and production methods.
- **Thermal Catalytic** - In-situ refining/upgrading technology would build on thermal oxidation, but preferably produce higher quality products, at lower temperatures, without the need to produce the bitumen to surface. Must

address methods of achieving the conditions for reactions in-situ, and distributing catalyst to achieve consistent and economic results.

- **Other Thermal Fluids** - Other hot fluids, or gases, might be injected or circulated as alternatives to use of water-based or reaction-based options. Possible options might be: hot oil cycling, flooding, heating or stimulation; hot gas injection/cycling with potential sources being flue gases from turbines, in-situ combustion of overlying low-pressure natural gas, etc.
- **Solvents** – Propane, butane, CO_2, and other potential diluents are known to change the properties of the bitumen, and possibly the properties of the surrounding matrix, and their use might be extended to in-situ applications. Key issues will be solvent selection, sources, transportation, recycle and recovery, as well as detailed and realistic assessments of the in-situ chemical, thermal and transport behaviors of potential injectants.
- **Enhanced Primary** – Covers potential methods of making more of the in-situ resources pumpable to surface, which has proven to be the most energy and cost efficient method of production. Currently, primary production only recovers a small portion of the in place resource, along with significant amounts of sand. Potential technologies might come from controlling the in-situ geomechanics; reducing near well pressure losses; adding vibrational energy; downhole pressure reduction; reducing the impact of overlying gas zones; and finding methods to block water inflow.
- **Chemicals** – Additives to change properties of oil/water/solid interactions without actually going into solution in the oil. Issues are similar to those for solvents.

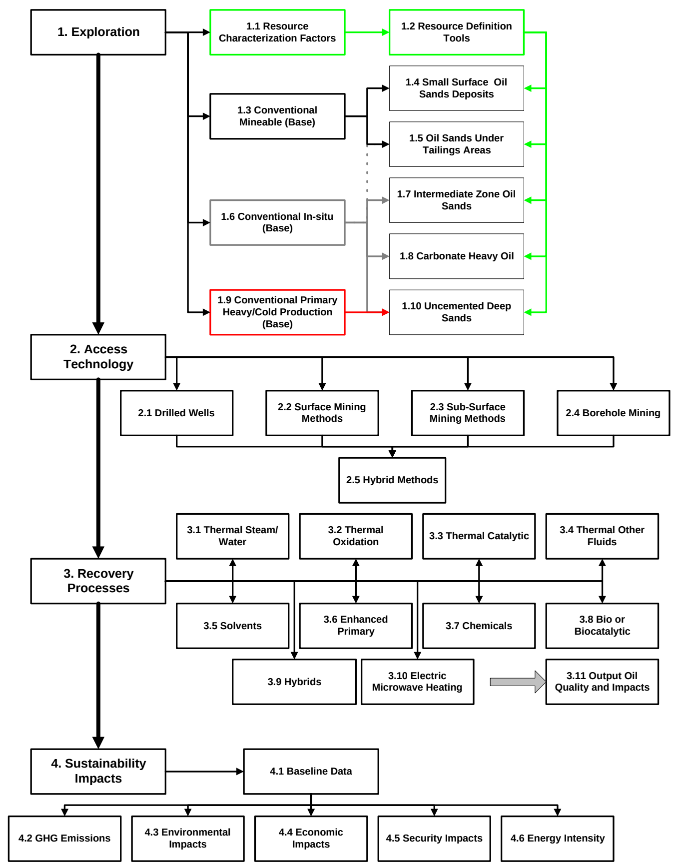


Figure 4.1 – Key Technology Areas

- **Biological or Biocatalytic** – Bio-based processing either organisms, enzymes or other biologically produced agents, may contribute to results similar to those using other catalysts, may assist with in-situ desulphurization, or with conversion of remaining bitumen or heavy oil into natural gas.
- **Electric/Microwave Heating –** Methods of enhancing well in-flow, or generating shaped heated zones, through electric or electromagnetic heating;

electric pre-heat; near well bore heating; surface effect current tracing (SECT) heating of casing; multibore, small diameter coiled tubing heaters.

- **Hybrids** - Concurrent application, or sequential application, of methods, which may perform better than any one method on its own. For example borehole extraction – hybrid of mining and in-situ extraction[7]; geothermal hot water plus direct contact steam generation.
- **Output Oil Quality and Impacts** – R&D into how the recovery method(s) used impact the quality of the oil, and how upstream quality impacts downstream product value, and R&D into surface upgrading processes. For example, biodesulphurization upgrading yields low sulphur heavy oil, but the product still has long chains; thermal cracking products; injected catalysts or solvents produced back with oil.

4.4. Sustainability

- **Baseline Data Gathering** – Determining the initial conditions in new development areas, which have to be identified and assessed before development proceeds. The rapid pace of development of oil sands reduces the duration allowed for baseline studies and reduces their reliability over the long-term.
- **GHG Emissions** – Life cycle impacts on global carbon balance, with the main focus on emissions of CO_2 and methane.
- **Environmental Impacts** – Life cycle impacts of various technology and development options on: water quality and quantity; air quality; land impacts including: topographic, hydrologic, biodiversity; biome fragmentation; ecosystem impacts including unique species and ecosystems, regional parks and reserves; and regional human health impacts.
- **Economic Impacts** – Assessing both the winners and losers impacted by alternate resource and technology development scenarios, and potential methods of mitigating adverse impacts. E.g. regional industries, such as logging, hunting, fishing, shallow gas, coal, and regional communities.
- **Security Impacts** – Use of technologies to mitigate potential risks to various stakeholders in bitumen and heavy oil development. Producers (technical and capital risk management); Governments (long-term hydrocarbon/energy supplies and orderly, efficient development of resources); Individuals (job security, protection of investments in homes and career training, family well-being); Societal (minimize risk of large scale natural or human initiated events).
- **Energy Intensity** – Reducing long-term energy intensity of operations, including assessment of alternate energy sources such as coal, nuclear, geothermal, solar, or other sources. An important indicator is ratio of energy input to energy output.

[7] Yildirim Patents on borehole extraction.

4.5. Types of R&D Activity

R&D activities can be classified or described in many ways. For a particular invention, or discovery, research can be described with a development investment curve that illustrates the progression from a low investment in "Fundamental Research", through "Applied Research", "Demonstration", "Commercialization" and "Market Research", which works well for a specific product. However, in this study, we are trying to address R&D for production of a single commodity: bitumen/heavy oil, from a very broad range of deposits, at various stages of exploitation. Therefore, progress may not be linear. Instead, we will try and indicate the types of R&D activities that appear to be currently required to move ahead a given area of investigation. To provide some consistency with a previous study on Conventional Heavy Oil R&D[8] the R&D activities will be defined as:

- **Theory Development** – Theories in the technology area need to be articulated, and tests proposed to challenge the theory. (Scientific Method)
- **Investigation** – Detailed investigations needed to establish potential methods of testing or assessing theories or to compare potential options or choices for a given application.
- **Data Collection/Analysis** – Widespread data collection is necessary to ensure theories can be tested and utilized. Data collection is combined with analysis, as data collection alone provides no knowledge, and quality can be suspect.
- **Piloting** – Application of theories to increase production and recovery of a given resource, on a smaller scale.
- **Field Trials** – Assessment of specific technologies to support improved performance.
- **Motivation** – Investigation into why improvements that are possible, and economic, are not implemented by industry. Assessing barriers to adoption, or developing tools to assist with technology transfer.
- **Risk Management** – Looking for ways to avoid costly problems, in the medium to long-term.

4.6. GHG & Sustainability Impacts

As this is a high-level roadmap, it is impossible to quantitatively assess the potential impacts any potential R&D result might have on GHG, or sustainability issues. Therefore, in this study, we will only differentiate between direct and indirect impacts and the potential for a large impact based on the percentage of the expanded resource base it might apply to. Terms used, mainly in Appendix B, are:

- **Indirect** – Efficiency improvements in the use of new, or existing, recovery methods, resulting in incremental reductions in GHG emissions, or increased sustainability of operations.

[8] Peachey, Bruce, "Conventional Heavy Oil R&D Needs Including GHG Intensity Reduction" PTAC, August 2005

- **Direct** – New recovery technology, or significant process modification of existing technology, resulting in inherent reductions in GHG emissions, or increased sustainability of operations.
- **Large** – Measurable impact on current and future operations applicable to 25% or more of the total bitumen resource.
- **Moderate** – Measurable impact on current and future operations applicable to 5% to 25% of the total bitumen resource.
- **Minor** – Measurable impact on current and future operations applicable to less than 5% of the total bitumen resource.

5. Carbonate Triangle

While bitumen is generally associated with oil sands, 71.1 billion m^3, or 26% of Alberta's bitumen resources, are contained in carbonates rather than sand formations. The "Carbonate Triangle" deposits have been identified in this study, and in others, as being one of the most technically challenging of the "Inaccessible Bitumen Resources", and if solved could result in a significant expansion of bitumen resources. This is not a new realization, as carbonates were originally targeted for technology development, by AOSTRA, in the 1970's and 1980's, and did see the development of production pilots, but with mixed success. However, they also showed promise as being capable of producing bitumen at high rates, if the right technologies can be developed and applied in the right places.

5.1. Description of Resource

There are four bitumen bearing carbonate formations in Alberta, but the most significant one is the Grosmont Platform in the Athabasca region. These formations may contain vugs, up to 10 cm in size. Many have significant inter-crystalline porosity and can be fractured.

(billion m3)	Deposit	Volume In Place	Percent Total
Athabasca	Grosmont	50.5	71.0%
	Nisku	10.3	14.5%
Peace River	Debolt	7.8	11.0%
	Shunda	2.5	3.5%
Total		71.1	100%

Table 5.1 Bitumen Containing Carbonate Formations

An important challenge is that the formation is highly variable over short distances because of the complexity of the natural fracture system.

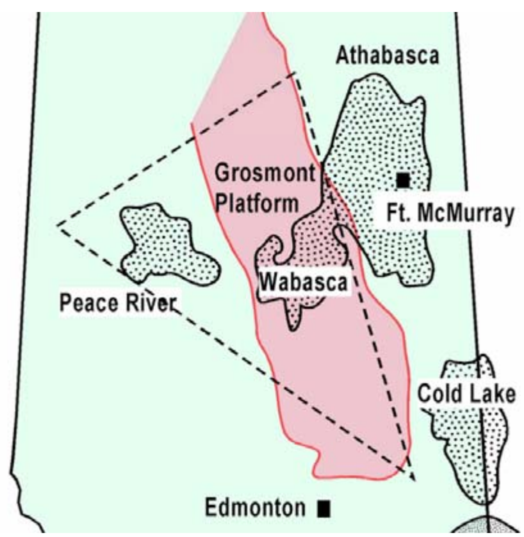


Figure 5.2 – Location of the Main Carbonate Triangle Deposit (Source AGS)

The Grosmont Platform has the following characteristics:

- o Approximately 500 km in length and 150 km in width;
- o Buried at depths ranging from 250 m to 420 m with a total thickness of approximately 170 to 180 m;
- o Pay thickness varies considerably from 25 m to over 80 m.
- o Bitumen saturation is high.
- o Bitumen accumulation is highest on the eastern margin.
- o The bitumen is heavier than in Athabasca oil sands, with API gravities between 5° to 9°.
- o The Grosmont is eroded and sub crops at the Pre- Cretaceous unconformity.

- Bitumen and gas are trapped along the Grosmont sub crop edge with Cretaceous shales as cap rock.
- The Grosmont Formation is composed of four units, separated by shale beds. They are listed below, from top to bottom:
  - Upper Grosmont 3: Thick and rich in bitumen accumulation; however, it is less attractive for initial development because of overlaying gas pools and thief zones; natural gas is sometimes found at the top of the Grosmont unit 3 in the pre-Cretaceous unconformity area;
  - Upper Grosmont 2: Relatively thick laterally extensive pay; has been the primary target for production pilots in the 1970s and 1980s;
  - Upper Grosmont 1: Relatively lower porosity and bitumen saturation and thinner pay zones;
  - Lower Grosmont: least attractive zone.

The Grosmont was the object of three recovery pilots in the 1980s. Results were described as "spectacular but erratic", and the production pilots were abandoned when oil prices dropped and funding for the pilots was reduced. The formation presents considerable challenges for access, drilling, completions and steam containment:

- Drill bits sometimes dropped a few meters when passing through karsted zones at the top of the unit.
- The irregular network of vugs can lead to a loss of mud circulation while drilling.
- Difficulties were experienced in placement of cement, for well to formation bond.
- High bitumen viscosity;
- Low effective permeability;
- High reservoir heterogeneity;
- Dual porosity system;
- Poor containment of injected fluids;
- Geographically isolated area with poor road access; and,
- Designated caribou migration area.

However, the problems encountered 20 years ago, during the pilot trials, could be solvable today. The industry now has drilling technologies, such as horizontal wells, and well completion technologies, which could increase the likelihood of successful recovery of bitumen from carbonates.

The following is a brief description of the early pilots in this deposit, which serve to give a sense of some of the issues and problems with carbonate developments.

5.1.1. Buffalo Creek Pilot (Union Oil, Canadian Superior and AOSTRA)

In 1975, the Union Oil Company of Canada operated a single well steam stimulation project at its Chipewyan River site in west Athabasca (T88 R19W4). In 1976, Union Oil filed an application with the Energy Resources Conservation Board (ERCB), for an experimental heavy oil recovery scheme in the Buffalo Creek area in the same Township. Canadian Superior and AOSTRA were partners in the Buffalo Creek pilot. The target formation was the Grosmont unit 2. The purpose of the pilot was to investigate communicative heating approaches to bitumen recovery, and evaluating potential problems with high permeability thief zones. The pilot also sought to evaluate the potential of producing natural gas from the Grosmont unit 3, which overlies unit 2.

The scheme was to inject 80% quality steam, and to observe steam movement through observation wells drilled 30 m on either side. Radioactive tracers in the steam were used to monitor preferential channels in the formation. After steam injection the injection well was to be produced. The next phase of testing would have been a steam drive and/or a wet combustion test.

Table 5.2 – Carbonate Pilot Information

Reservoir Parameters for Carbonate Production Pilots			
	Buffalo Creek	**McLean**	**Algar**
Average Formation Depth (m)	295	295	300
Formation Temperature (°C)	10	10°C	24
Initial Reservoir Pressure (psig)	150	150	200
Bitumen Zone Gross Pay (m)	30	30	25
Net Pay (m)	20	20	
Porosity (%)	20.4	20.4	14.1
Bitumen Saturation (%)	78.8	78.8	
Pore Oil (%)			55
Water Saturation (%)	16.2	16.2	
Pore Water (%)			32.8
Gas Saturation (%)	3.0	3.0	
Source: Energy and Utilities Board			

Access to the site was via a 140 km winter road from Wabasca. The absence of permanent access to the site meant that fuel, and other supplies, could only be trucked in the winter. Winter roads also allowed trucking of bitumen to market. However, during other times of the year, bitumen was re-injected into the Grosmont formation. Other produced fluids from the test were also injected back into the Grosmont formation.

The well penetrated 120 m of the Grosmont formation, at depths between 380 m and 260 m. The net pay was estimated at approximately 30 m. The well was cored, and permeability was found to be greater than 10 millidarcies with an average porosity of 16.7%. However, porosities greater than 40% were obtained from 4 measurements. Oil saturation averaged nearly 80% oil, containing 3 to 5% sulphur. Oil in place was estimated at 210 m^3 (1,300 barrels) per acre-foot. No gas was expected from the Grosmont unit 2. Solution gas from the bitumen was expected to be negligible. High production rates of over 70 m^3/d (440 barrels per day) were achieved.

In 1981, the well was in its fifth steaming cycle and the operators indicated that each injection/production cycle had provided unique and encouraging results. The pilot termination criteria, of two consecutive cycles indicating a deteriorating trend, had not yet occurred by 1981. By 1984, the well had completed its ninth steam stimulation cycle and was still producing, while a second well was in its second cycle. In 1985, Union Oil applied to drill yet another well to further investigate production and communication issues. However, the pilot was terminated in 1986.

5.1.2. McLean Pilot (Union Oil, Canadian Superior and AOSTRA)

In 1982, Union Oil applied to the ERCB for approval of an experimental heavy oil recovery scheme, in the McLean area, targeting the Grosmont formation (T87 R19W4). The objective was to obtain reservoir performance information by cyclic steam stimulation in a multi-well pattern. The project was to determine pertinent information, such as well spacing, slugs size, timing of interference, calendar-day oil rate and steam oil ratio.

The zone of interest was the Grosmont unit 2, which at the pilot location, is reported to be a uniformly thick unit. The porosity is fairly continuous and is bitumen saturated throughout the zone. The Grosmont unit 3 formation lies above unit 2, and is about 29 m thick. The Grosmont unit 1 formation lies below unit 2, and is roughly 16 m thick. All of these formations are hydrocarbon bearing. These three units are separated by shales, 1 to 3 m thick, which were believed to form permeability barriers between the units. In the vicinity of the pilot, the Grosmont units are relatively laterally continuous except where channeling eroded down into the Upper Grosmont. There was no gas found in the Grosmont unit 2. Any gas in place may only be minor quantities in solution.

First steam injection was planned for July 1982. Steam would be injected in cycles, which would continue until production data would be no longer useful. At that point, a steam drive test, from a central injector, would be considered. Loss of steam containment occurred because fractures, or vugs, established communication between the Grosmont units 2 and 3. There was also premature steam breakthrough from injection to producing wells.

In 1985, only one well was still active in the McLean pilot. Union Oil filed an amendment to its original application to drill an additional well. The purpose was to continue to investigate recovery of bitumen of the Upper Grosmont, to establish single well parameters for cyclic steam stimulation, and to establish reservoir performance and productivity parameters for the formation. Another objective was to investigate Grosmont unit 3 productivity and investigate communication between the units. However, the pilot was terminated in 1986.

5.1.3. Chevron Algar Pilot

In 1975, Chevron Standard Limited applied to the ERCB for a steam stimulation pilot in the Algar area, location Township 81 range 17W4. Chevron was planning to cyclically steam stimulate unit 3 of the Grosmont carbonate formation, for production of bitumen in a single well scheme. The objective of the pilot was to determine if steam stimulation of the Grosmont carbonate formation would be feasible for the recovery of bitumen. The operation was conducted in the winter of 1976 until spring break up. The company expected that there would be sufficient time for one or two steam cycles, depending on the results of the first cycle. One to two weeks would be required to inject steam, two days for soaking, and three to four weeks for producing. Access to the site was only through a winter road, as with the other pilots.

In the Algar area, the sands of the McMurray formation are poorly developed and the Grosmont Formation is underlain by shale deposits. The total Grosmont was anticipated to be 100 m in thickness, and unit 3 was anticipated to be 25 m thick. The pilot well was to be drilled 18 m into unit 3, with an average depth being about 300 m. The average reservoir pressure and temperature were estimated at 200 psig and 24°C. Production was estimated at 41 m^3/d (250 barrels of fluid per day), composed of 8 m^3 (50 barrels) of bitumen and 37 m^3 (200 barrels) of water per day. The bitumen produced was incinerated on the site.

5.1.4. Peace River Carbonates

In 1985, Pembina Resources applied to see ERCB to drill a single well thermal in-situ experimental scheme in the Seal/Chipmunk area of Peace River. The location was Township 82, Range 12W5. The target was a carbonate zone in the Pekisko formation. The reservoir is described, not as a reef, but as a “Pekisko carbonate mud mound build up” otherwise known as a “Waulsortian Mound”. Underneath the Pekisko formation are Banff shales, while the overburden consists of 32 m of Pekisko shales, topped by the 100 m thick

Shunda Carbonate Formation, which contains bitumen and heavy oil. However, Pembina believed that Shunda porosity was too low for commercial exploitation.

According to the application, the experimental scheme was to be carried out during the winter of 1985-86. It was a single well steam stimulation pilot, in which steam was to be injected for 20 to 25 days above fracture pressure. After steam injection, a soak period of one to two weeks was allowed. Then, the well was to be produced until liquids became too cool for production. Produced liquids, water and bitumen, were to be trucked away for treatment. Production was expected to last four months or longer.

5.2. Current Understanding of Limits – Limited Assessment

With the currently limited amount of piloting results available, it is difficult to determine the limits of potential development of this resource. The initial single well pilot achieved high production rates, with a steam stimulation process. However, other pilots showed early breakthrough using other processes. The current view is that the primary target zone should the Upper Grosmont 2 formation. The Upper Grosmont 3 is thick and rich but less attractive due to concerns about overlaying gas pools and thief zones. A greater review of data and geology is necessary to fully assess the potential limits of development with the current understanding of existing technology options.

5.3. Exploration – Defining the Resource

Due to the limited activity in this deposit type, there is a shortage of data on the geological properties that might impact access, process and sustainability development directions for the resource. A solid rock matrix has few similarities to the relatively uncemented matrix, which is found in the oil sands deposits. Some of the options, discussed later for carbonates, would require extensive investigation into the geology of the deposit and overlying or underlying zones, as well as analysis of past pilot information. The additional information would allow development of new theories on how the chemical and physical environment of the bitumen in carbonate deposits might impact potential development.

R&D Direction 1.8.1 – Mapping Carbonate Characteristics – Investigation. The Alberta Geological Survey (AGS) has prepared an initial study of the Grosmont carbonate formation based on the limited data available, which mainly comes from areas that are easy to access on surface. Significantly more data and information needs to be collected to enable identification of “Sweet Spots” in the formation, which are more likely to be economically developed in the next 20-50 years.

R&D Direction 1.8.3 – Mapping Co-located Assets – Investigation. Portions of the carbonate formations are co-located closer to many potential synergistic development assets than are other oil sands deposits. Investigations should be undertaken to determine potential use of: geothermal energy, commercially mineable coal, overlying and underlying natural gas deposits. They also are closer to potential CO_2 and acid gas storage sites than many conventional oil pools.

R&D Direction 1.8.4 – Review Past History – Data/Analysis. Reports on initial piloting efforts, in the late 1970's and early 1980's, were prepared for AOSTRA and other project participants. Most of the key findings on recovery results have been made public over time. However, a great deal of the value of these reports are in the details of geology, reservoir characteristics, drilling and observations during production. These reports are currently confidential, but need to be made available, and re-analyzed, in light of current understanding of bitumen production and access methods.

Aside from assessing the initial state of the reservoir, bitumen properties, and disposition within the deposit, effort is also required to determine how the reservoir environment might be affected by potential induced conditions. Understanding how the formations might react to the imposed pressure (fracturing), temperature, or injected substances such as steam, water, gases, acids or other chemicals will need to be studied.

R&D Direction 1.8.2 – Considering Potential Behavior (Solid in Solid) – Theory Development. The bitumen in the carbonates has been reported as 5^{o} to 9^{o} API, which is heavier than Athabasca. At reservoir conditions this is essentially a solid, and high bitumen saturations, provide little potential for flow through the reservoir matrix. Therefore, new theories need to be developed on behavior of the solid rock and bitumen to enable development of potential recovery processes.

5.4. Access - Unique Deposit Issues

Canadian oil and gas producers have had considerable experience with carbonate deposits, containing light and medium crudes or gas, and other mineral developers have experience mining in carbonates (limestone). However, the bitumen deposits in the Carbonate Triangle appear to be more broken up and heterogeneous than what may have been encountered in other Canadian applications, as they are close to surface and have been extensively affected by glacial pressures and groundwater flow. The highly broken up nature of the deposits, will make any access options more difficult and will likely require a greater effort to plan, and execute access, than would be the case in other carbonates. The primary focus for access R&D, in carbonates, is to look for methods of dealing with the high heterogeneity, and adapt those methods to the various access and recovery processes, which might eventually be used.

Figure 2. Vuggy dolomites of Upper Devonian Grosmont Formation at Harper Creek.

Figure 5.3 – Vuggy Fractured Carbonate Drilling Challenges (Photo – AGS Rock Chips Spring/Summer 2003)

R&D Direction 2.1.1 – Drilling in Carbonates – World-wide Experience – Investigation. World-wide the oil and gas industry has drilled into and through a wide variety of carbonate deposits. This body of knowledge and experience must be reviewed to find analogues to the carbonate triangle deposits and how others have coped with similar issues for drilling and completing wells. For example how to deal with large karst features, which can cause the drill string to suddenly drop, or completing in highly permeable formations (open-hole or cased).

R&D Direction 2.3.1 – Methods for Mining in Carbonates – **Investigation**. Sub-surface mining methods might be options for carbonates as part of a hybrid access system (e.g. shaft, tunnels and wells). Carbonate formations are relatively easy to mine and are stronger than oil sands. Mining has potential to increase recovery as it is less impacted by heterogeneity than in-situ processes. Mines in more competent carbonate might also be used to assist in-situ methods similar to the Underground Test Facility. (See Section 7 for more on mining options)

In addition to looking at other areas where carbonates are drilled or mined for other purposes, there may be new options that could take advantage of the unique properties of heavy oil at high saturations in carbonates. In these cases the presence of the heavy bitumen may be an asset rather than a liability.

R&D Direction 2.5.1 – Adapting to Carbonate Characteristics – **Investigation**. As much of the knowledge related to bitumen mining and extraction is related to oil sands, much of it will have to be repeated for bitumen in carbonates. Novel surface extraction methods not suitable for oil sands may be suitable for mined bitumen in carbonate. E.g. the Alberta Taciuk Processor (ATP).

R&D Direction 2.1.2 – Methods for Solid in Solid – **Theory Development**. Research could be undertaken to develop ideas for drilling in these deposits by use of techniques such as chilled drilling fluids, to prevent bitumen from mobilizing during drilling.

5.5. Processes – Producing Solid Bitumen from Sold Rock

The considerable differences between carbonate rock and oil sands will have a significant impact on the applicability of potential recovery processes. The higher strength of carbonate rock makes it less able to expand and fracture than oil sands, while the high bitumen saturations result in little, if any, initial permeability at reservoir conditions. The large vugs, fractures and karst (cavern) features in the deposit should allow high production rates if those features are accessed, but will also potentially hinder recovery from smaller fractures and pores in the rock matrix. Therefore a focus for new process development and testing should be to consider proven thermal methods, adapted for carbonates, and potentially including low cost injectants that can enhance access to oil by intentionally degrading the surrounding carbonate matrix.

R&D Direction 3.1.1 – Assess Current Thermal Options in Carbonates – **Piloting** – While early pilots in this deposit were eventually discontinued, they did show promise, even using recovery processes which have never been commercially applied in conventional oil sands. Advances in the last 20 years in oil sands, such as SAGD and CSS processes, should increase the likelihood of recovery from carbonates. This requires resumption of piloting.

R&D Direction 3.4.1 – Hot CO_2/Combustion/Acid Gases Injection – Investigation/Piloting. Injection of hot acid gas, or flue gas streams, may provide a means to access bitumen in small fractures in the carbonate, as the gases can react with the carbonate to change its properties. Absorption of the CO_2 and acid gases by the formation would also serve to sequester the emissions.

R&D Direction 3.7.1 – Acid Voidage Generation – Sulphuric Acid Injection – Investigation – Unlike oil sands, carbonates are affected by acid injection, which could be used to stimulate near-well communication as it is in conventional oil carbonate formations.

Hybrid Processes – A combination process, to continuously inject thermal steam, hot gases and acids could provide significant benefits, while also lowering energy costs.

R&D Direction 3.9.1 – Direct Contact Steam Generation in Carbonates – Investigation/Piloting. Direct contact steam generation, downhole or on surface, could provide low cost thermal and chemical energy to carbonate formations, at high energy efficiencies. This technology was originally developed in the 1970s for downhole steam generation in deep heavy oil formations where heat loss to the wellbore was high. It was not suitable for CSS operations, due to the high cost of removing and reinstalling the system downhole and the requirement for corrosion resistant tubulars. However, in a continuous shallow SAGD process, especially where CO_2 might aid recovery, this process should be reconsidered. Direct contact generation would capture combustion water (1 tonne/tonne of liquid fuel or 2 tonne/tonne of natural gas), SO_2 (from bitumen combustion) and energy (20% based on higher heating value). Water would require minimal, if any, treatment, as scale would form on the water surface, and deposit in-situ rather than on tubes. This is essentially a more controlled version of wet in-situ combustion.

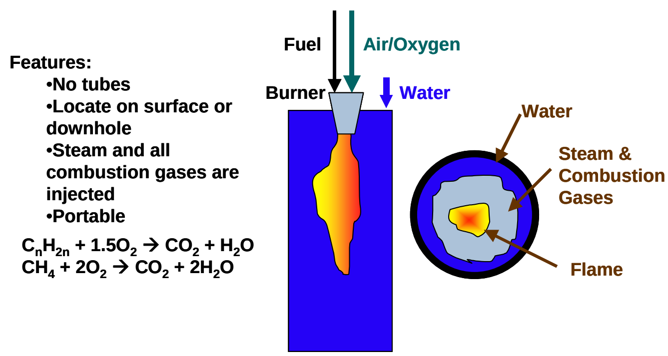


Figure 5.4 – Vertical Direct Contact Steam Generation Concept – Vertical Orientation May Help to Maintain a Uniform Water Wall

5.6. Impacts on GHG and Sustainability – Opportunities for CO_2

Potential production from the Carbonate Triangle areas offers a number of potential advantages, from sustainability perspectives, which require further investigation and study as development alternatives. Producing bitumen from two geographically, and geologically, distinct deposits can generate numerous opportunities for synergies to maximize benefits, such as distributing development over a wider area, or facilitating access to alternate energy sources such as coal or geothermal energy, while minimizing consequences.

Baseline Data - The land areas overlying the carbonate triangle are, for the most part, relatively undeveloped, with large tracks of muskeg. There is some development of gas pools in the region and some logging, but few communities or all weather roads.

R&D Direction 4.1.1 – Relatively Undeveloped Area – Ecosystems and Water – Data Collection/Analysis. To date there has not been any extensive review of ecological or ground water resources in this area, which should be started now in preparation for later development.

GHG Impacts - From a GHG perspective one of the greatest attractions of the carbonates is the potential that the formations may absorb CO_2, either through absorption/reaction with the rock or other means. They potentially could not only absorb emissions from their own development, but also they could be large enough to potentially absorb CO_2 emissions from oil sands upgrading sources in the region. Conventional oil and gas reservoirs in Western Canada only have limited ability to absorb CO_2 for short-term utilization for EOR. Therefore, if sequestration is to be viable in the long term, alternate value-added sequestration deposits are needed.

R&D Direction 4.2.1 – Potential for CO_2 Sequestration – Investigation. Exploring the potential interactions between carbonate and CO_2 should be an early research focus. GHG reductions could also be realized from use of geothermal energy, which would be found at shallower depths in the carbonate areas (See Section 14.4). Even accessing 120° C hot brine, from underground sources, could potentially reduce carbon intensity by 5-10%.

Economic Impacts - Prioritization of whole oil sands deposits for sequential development is not a realistic strategy, as every type of deposit has "sweet spots", which exhibit greater than average richness, access, containment, saturation or depth, and which could potentially be developed and made economic, even at low oil prices. Also, many of the existing oil sands leases are very large, and it will take large developers many decades of effort to fully deplete them. Yet, they are not accessible to new developers. Other potential synergies are more difficult for operations in Ft. McMurray, due to surface mining operations, but may be advantageous in the Carbonate areas.

R&D Direction 4.4.1 – Indications of Potential for Sweet Spots – Investigation - Finding sweet spots in carbonate deposits will need to be an early activity. Early AOSTRA pilots indicated that relatively high production rates are possible in the right areas.

R&D Direction 4.4.4 – Lease Availability Allows New Players In – Motivation – Large integrated producers tend to be risk adverse, while smaller producers thrive on differentiating themselves through use of novel new technologies. The carbonate area still has large areas of open oil sands leases that could be acquired by smaller players.

R&D Direction 4.6.1 – Closer to Developed Coal Resources – **Motivation** – Fully or partially developed surface coal mining operations are found to the south west of the carbonate areas. With coal energy estimated at $1-2/GJ[9] vs. $3-4/GJ for bitumen and $6-8 for natural gas, coal could become a preferred energy source for carbonate development, if coal transportation costs can be kept to a minimum.

Environmental Impacts – Diversifying development activities between deposits, and deposit types, can have potential benefits from environmental, as well as economic synergies. Cumulative impact assessments are a key to making the best policy and investment decisions on major resource developments, such as the oil sands.

R&D Direction 4.3.1 – Carbonate Absorption of Air Emissions – **Investigation**. Potential interactions between the carbonates and other potential air emissions should also be an early area of investigation, to determine the ability of the carbonates to absorb SO_2 and other air contaminants from oil sands production.

R&D Direction 4.4.3 – Synergies by Integrating with Clean Coal – **Investigation** – It has been suggested that coal could supply hydrogen and energy for oil sands development, and that bitumen and coal co-processing and upgrading could provide significant synergies. Ultimately, clean coal technologies could also be applied to bitumen/coal mixtures.

Security Impacts – Many issues have been raised concerning high-level and local security impacts associated with concentrating production of a large percentage of Canada's oil production, in a single community and infrastructure system. Interruptions due to forest fires along the main transportation corridor into Ft. McMurray have already caused disruptions and concerns about congestion. Having all major road, rail, pipeline, and power transmission infrastructure, related to oil sands development in a small number of corridors, presents an attractive target for disruption of North American energy supplies, especially, as the oil sands become a larger part of the total North American supply picture in coming decades.

R&D Direction 4.5.1 – Separate Bitumen Supply – Risk Management – At a provincial, and national, risk management level, diversification of supply sources has potential advantages. Most of the current development is focused on Ft. McMurray, which has limited north–south and east–west access, and shares some common infrastructure with Cold Lake, the other major commercial development region. Developing more bitumen production to the west in the Peace River and Lesser Slave Lake Regions, with one or two parallel infrastructure developments, would take some pressure off Ft. McMurray and reduce the risk of a singe event disruption of all oil sands production or sales.

R&D Direction 4.4.2 – Move Activity out of Ft. McMurray – **Risk Management** - At a local, company and individual risk management level, moving some development and operating activity out of the Ft. McMurray area, which by necessity must be the center of mined oil sands development, may have positive benefits.

[9] Huq, Iftikhar and Amarnath, Amar, "Synergies between Coal and Oil sands in the Alberta Energy Economy" Presentation at the Oil sands 2006 conference at the University of Alberta. February, 2006.

The growing pains and benefits of in-situ developments might be more evenly shared between local communities across northern Alberta. Companies would be able to develop and operate with fewer potential conflicts with adjoining leases, which cause cost over-runs. Individuals would be able to enjoy a slightly more stable economy, with less potential for disruptions to their personal lives. This assumes that total oil sands production will reach some limit, and not continue to grow at the current pace.

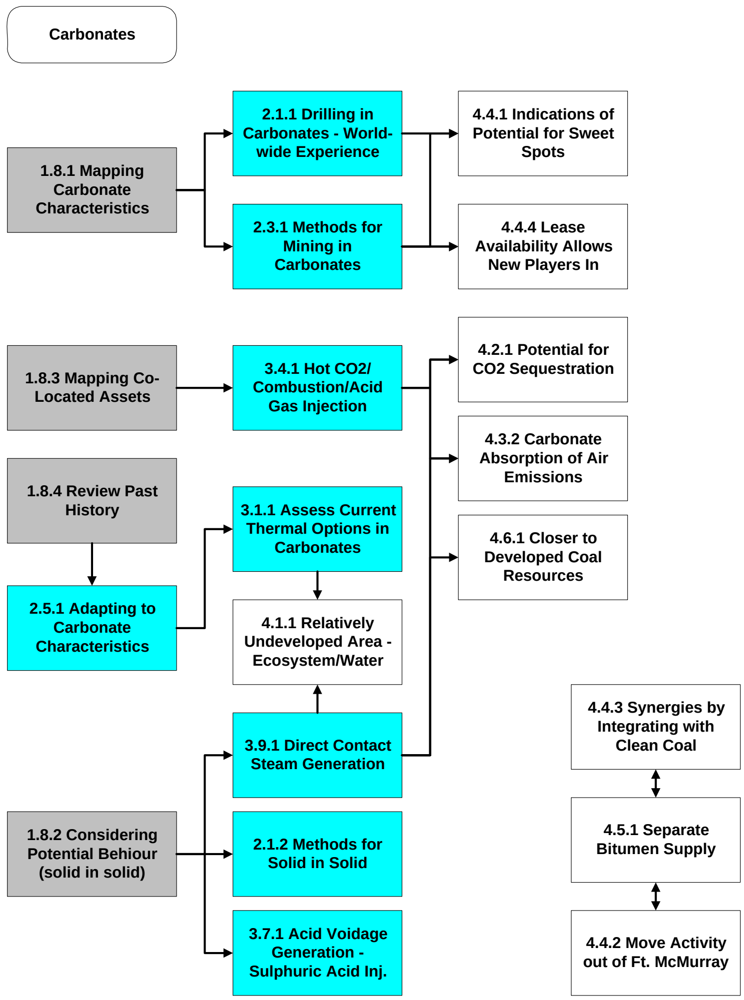


Figure 5.5 – Suggested Carbonate R&D Directions

6. Unconfined Resources

Originally the focus of this study was to be only on "intermediate" oil sands that were too deep to mine and too shallow to produce. However, as the project progressed, it soon became obvious that depth had less to do with in-situ production than other characteristics of the oil sands or carbonate deposits.

In intermediate zones, the main deposit characteristic, which will impact long term recovery and process efficiency with current technologies, is the degree of containment of a given portion of the oil sands or carbonate deposit. Unlike most hydrocarbon resources, bitumen resources in shallow deposits are held in place by their properties, rather than by impermeable caprock. For some areas of the shallow oil sands, any caprock, which might have been there originally, has long since been scoured away by glacial action, and any remaining caprock layers have likely been fractured by the same forces. Some areas of the oil sands contain relatively fresh connate water, which implies that they are in relatively free communication with groundwater streams.

In this section we will primarily focus on containment, or confinement, in oil sands areas, however, the same issues apply to bitumen in carbonate formations like the Upper Grosmont 3, which showed, in limited pilot testing, to be in communication with shallow gas zones, or showed rapid loss of containment after short periods of steaming.

6.1. Description of Resource

Unconfined resources come in three main types of deposit that have currently been identified and outlined with some mapping.

6.1.1. Deposits with Insufficient Cap Rock, Shale or Clay Barriers

Some deposits, mostly in Athabasca, lack sufficient overlying rock, shale or clay barriers for effective containment of steam. These deposits are located mostly in the northeast quadrant of Athabasca, where glacial erosion has removed the shale or clay barriers between the oil sands and overlying sediments. Throughout much of this area, bitumen exists at depths greater than 50 m, but the recovery factor is assigned as zero because neither surface mining, nor standard thermal in situ methods, would be capable of operating in this situation.

6.1.2. Deposits Too Deep for Surface Mining but Too Shallow for SAGD

Intermediate zone oil sands are deposits that are too deep for surface mining but too shallow for SAGD. For the purpose of this study, intermediate zone oil sands are defined as oil sands at depths from 40 to 75 m. They represent a resource of 4.4 billion m^3 or 1.6% of the total oil sand resource.

However, depth is a crude estimate of recovery potential. The depth to which surface mining is economic is, in fact, dependent on several factors, in particular on the economic strip ratio, which is defined as the ratio of overburden material to recoverable mineable ore. Reducing the cost of surface mining, through technology improvements and economies of scale, would open up a significant amount of bitumen resources for recovery by surface mining techniques.

The minimum depth for SAGD is also subject to several factors. At first approximation, a shallower depth implies lower reservoir pressures, and therefore lower steam pressures and temperatures. Lower steam temperatures cause production rates to be reduced, but the steam to oil ratio is improved. However, the net effect is a higher total cost per volume of bitumen produced. So, for SAGD, depth is not a huge difficulty if there is a seal layer that can contain steam. A continuous 1.5 m shale layer is currently deemed to be an adequate barrier for steam containment. Low pressure SAGD approaches, using steam alone, or with added solvent/diluent mixtures, are currently being piloted in Athabasca, and a number of low pressure SAGD pilots were approved under the Innovative Energy Technology Program (IETP).

Finally, at least two commercial projects, Jocelyn and Horizon, are planning a surface mine, and an in situ development, on the same lease. Other SAGD projects are being located on leases that are immediately adjacent to existing surface mines. It is therefore reasonable to expect that incremental advances in technology, and increased collaboration between neighboring operations, will eventually succeed in recovering bitumen from the intermediate zone.

6.1.3. Deposits in Communication with Low Pressure Gas Caps

The presence of shallow gas reservoirs overlaying bitumen deposits has received considerable attention from the industry and the AEUB. The issue is that the bitumen zone is in communication with the gas zone and, therefore, steam injected into the bitumen zone could escape into the gas zone. In effect, the gas zone becomes a thief zone that may severely reduce the effectiveness of the thermal process.

In cases where gas reservoirs are currently at a sufficient pressure to avoid the escape of steam from the bitumen zone, the AEUB has ruled that these gas reservoirs cannot be produced, in order to maintain their pressure and to protect the ability to recover the bitumen by using SAGD type technologies. These bitumen deposits are deemed recoverable because the gas zones are shut-in under a conservation order. It should be noted that a number of projects approved under the IETP are targeting technology solutions for this issue.

However, there are already gas reservoirs overlying bitumen deposits that are currently at a pressure too low for containment of steam. These reservoirs were either naturally at a low-pressure, or have already been depleted through earlier gas production. There is no current commercial technology that can recover bitumen from deposits in communication with low-pressure gas zones. As a result, these bitumen deposits have a recovery factor of zero.

6.2. Current Understanding of Limits – Containment Assessment

So far the longest operating in-situ operations (for CSS, SAGD or other processes) have been in reservoirs buried at depths from 400-1000m. In those deposits the issue of loss of containment has been limited to casing failures in shallow portions of the wells, causing loss of steam and/or production to underground aquifers or, in some cases, blowouts to surface. In theory the SAGD process should result in lower risk of containment losses, due to casing failures. However, at shallow depths there are fewer geologic barriers to steam flow to surface, or water infiltration to the producing chamber, except for the seal provided by the bitumen itself. Even if pressure balances are maintained, so that chamber pressures are similar to hydrostatic pressure, steam and vapors can escape and water can flow in, due to density differences. SAGD and other non-fracturing processes may also be unable to break through shale and clay barriers inside the oil sands deposits. In thick oil sands deposits these factors may not be of immediate concern, however, they do pose a threat to on-going production and recovery from unconfined deposits, or deposits with extensive shale or clay barriers.

As a result of these two factors, the properties of any barriers that exist above, below or inside the deposit, can have a major impact on long-term sustainable operations. Learning about the properties, extent and effectiveness of these barriers becomes a significant focus of investigation.

6.3. Exploration – Assessing Barriers

A major challenge in barrier assessment is to gather data on barriers prior to the start of development of a given deposit. In thick zones, projects may reach payout and still be economic even if barriers do ultimately cause problems; however, ignoring the potential impact of barriers could lead to sub-optimal lease development, loss of ultimate reserves and losses in production energy efficiency. Greater effort is required to learn about the barriers and to develop non-intrusive tools, which will allow pre-development assessment of the effectiveness of the barriers.

R&D Direction 1.7.2 – Learning from Gas-Over-Bitumen Areas – Data/Analysis – Even where barriers appear to exist on the top of the oil sands deposits, the barriers may contain fractures or channels where containment can be lost through the barrier gap. Potentially some knowledge of barriers could be gained in Gas-Over-Bitumen (GOB) areas by detailed mapping (as was undertaken by the AEUB) and also by assessing if, and how fast, depleted GOB zones refill with water. Rapid refill of GOB zones with water would indicate poor isolation from groundwater, even though there is obviously enough cap-rock to trap some gas.

R&D Direction 1.7.3 – Detecting and Assessing Barriers – Investigation – There are a variety of shallow and deep seismic, or sub-surface assessment methods, which might be able to assess the extend and integrity of barriers. These may require calibration or testing to demonstrate their value, and such work could be undertaken at oil sands mining leases by using the methods and then comparing results with what is later mined from a given area. Intrusive methods, such as core hole drilling, could damage the integrity of any flow barriers and may have to be avoided.

6.4. Access – Breaking and Building Barriers

Once barriers have been assessed, new technologies, which can either break or build barriers, would allow producers of the resource to have more control of their own fate. Understanding of properties of deposits and barriers can help to assess options for breaking down barriers, which impede in-situ operations, or build barriers to maintain or restore containment in a given producing area.

Breaking barriers may be required to allow injected steam, or other materials, to move in the reservoir as required, to allow operation of well pairs and optimum development of steam chambers. If a barrier exists between the upper and lower wells of a SAGD pair, then it may be impossible to develop communication between the wells, to allow fluid circulation. Breaking barriers may also be required to allow growth of steam chambers to their optimum dimensions. If barriers hinder chamber development, then either recovery will be lower, or additional wells may be required above the barriers.

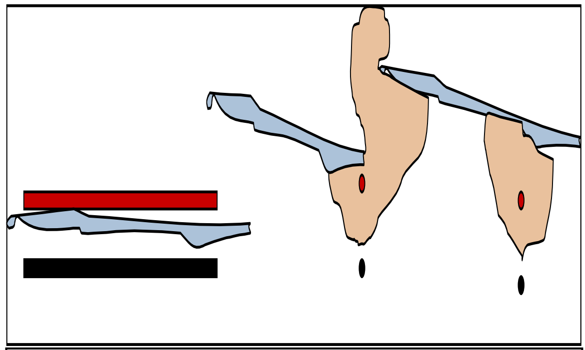


Figure 6.1 – Impact of Barriers on Communication Between Well Pairs (left) and Steam Chamber Development (right)

R&D Direction 2.1.3 – Break Barriers – Data/Analysis. There have already been reported cases where well pairs have not communicated, possibly due to an intervening barrier. Gaining a better understanding of how communication is opened between wells may provide insights into a better understanding of breaking barriers between wells. In some cases, communication may be assisted by drilling procedures that generate local hydraulic pressure gradients, which may break down fragile barriers. Gathering and analyzing drilling, completion, geologic and production data on a large number of SAGD well pairs may, provide insights on inter-well behavior and chamber growth factors.

Building Barriers – In cases where there is no confining overburden or where the overburden is weak, technologies that could be used to build barriers to prevent either vertical or horizontal fluid flow would be needed. Ideally the techniques would use locally available materials, as the volume of barrier material required may be quite large. Potential materials might be freeze-walls (using winter temperatures to stop underground water flows); sulphur barriers; plugging permeable zones with fine tailings; or use of locally manufactured cement (using local limestone, waste heat and exhaust emissions). As with barrier assessment, the existing mining areas could be used to test placement of barriers in

Figure 6.2 – Barrier Concept using Sulphur Cement

the overburden layers, and allow for dissection of the overburden to assess in in-situ condition of the formed barriers.

R&D Direction 2.5.2 – Building Barriers – Investigation. Access information on development of cold walls and use of thermal siphons, in Arctic and northern development, with a focus on blocking groundwater flows into a development area. Investigate methods of pumping molten sulphur and/or cement into horizontal fractures or boreholes created between the top or bottom of the oil sands and the over or under burden.

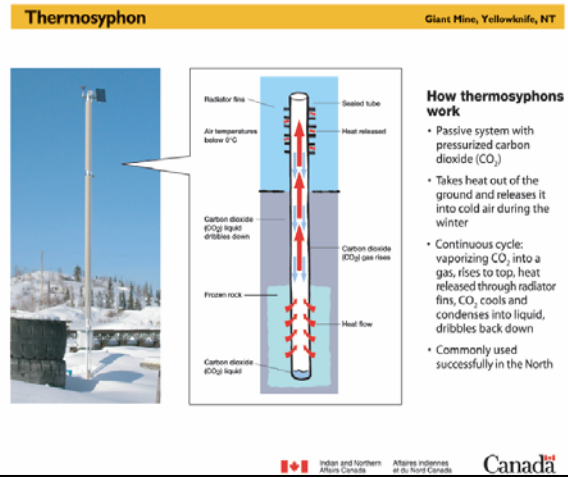


Figure 6.3 – Barrier Concept using "Cold Energy" Freeze Walls

6.5. Processes – Low Pressures and Controlled Conditions

A modification of the SAGD process is to operate at lower pressures to avoid loss of containment. However, even at low pressures, formation dilation will occur and steam may breakdown some barriers (clay lenses) that provide containment. Due to density differences between steam/vapors and water, balancing pressures may not be sufficient. Performance of existing projects and pilots should provide information of value to development of other leases.

R&D Direction 3.1.2 – Low Pressures – Piloting – In shallow, or potentially unconfined areas, piloting must continue ahead of commercial development to identify potential issues which may arise later in the operation. Key pressure responses should be closely monitored to use for future analysis, in assessing the effectiveness and impacts of barriers in different pressure and geologic regimes.

R&D Direction 3.2.3 – Detecting Loss of Containment – Field Trials – Consideration could be given to designing and conducting small scale tests, in mining areas with deeper overburden or shallow and thin in-situ deposits, to intentionally simulate loss of containment events at the top of the oil sands, while monitoring resulting indicators and impacts. This could be used to develop monitoring methods for early detection of loss of containment (e.g. water quality or flows, methane releases, or ground heave, may be some indicators before a steam plume appears at surface)

6.6. Impacts on GHG and Sustainability – Managing Risks

Barriers in the deposit and limited containment add to risks for currently planned shallow in-situ oil sands development in thick zones. However, the risks will be even larger in shallower, thinner oil sands deposits and in areas where no caprock exists. The main priority in these areas should be on assessing the potential magnitude of near-term impacts and risks, putting in place monitoring to detect loss of containment, or initiating development of mitigation methods to reduce impacts, if problems prove to be greater than currently anticipated. The risk management focus should be on scenario development and assessment.

R&D Direction 4.1.2 – Groundwater and Connate Water Assessments – Data/Analysis. As recommended in other studies, better data collection and analysis of baseline ground water flows and resources should be a predevelopment requirement for oil sands projects. A baseline allows the use of monitoring to assist in detecting and analyzing impacts of a loss or lack of containment. In Cold Lake, there were concerns expressed about heat mobilization of arsenic in potable water zones, potential for this type of concern could also be assessed by investigation of the overburden.

R&D Direction 4.2.2 – Assessing Containment vs. Energy Input – Investigation - The main GHG impact of a loss of containment would be increased energy required to heat and manage additional water flowing into the deposit, and/or loss of steam into the overburden. Increased energy would increase combustion emissions in a thermal project. In thermal or non-thermal operations, the loss of product would potentially result in increased fugitive emissions of methane and/or other hydrocarbons, freed from the bitumen and seeping to surface.

R&D Direction 4.3.2 – Impacts of Mobilizing Bitumen into Overburden – Investigation - Another potential outcome of loss of containment may be mobilization of bitumen, or other hydrocarbon liquids, into the overburden, which could contaminate ground water sources, and result in production losses. Investigations into potential environmental impacts of such events would help to indicate the potential damage, and types of mitigation that may be required.

R&D Direction 4.4.5 – Limiting Recovery to Avoid Loss of Containment – Investigation – If an area under development is found to be suffering from a loss of containment, operations may have to be adjusted in a way that may limit ultimate recovery. Investigation into potential development strategies, which would minimize recovery loss, might be assessed in advance, to expedite reaction to any negative results.

R&D Direction 4.4.6 – Extended Piloting to Manage Risk – Piloting – As indicated in Section 6.5, there should be a focus on ensuring that pilot activities continue, and lead commercial developments by a number of years. This is necessary to help identify potential risks before they impact on commercial operations. Sharing of data and analysis between pilots, or confidential independent third party analysis through the AEUB or other organization, should be routinely undertaken to assess potential risk factors generated by various operating strategies and geologic environments. The probability of any one developer having all the information needed to assess an issue is extremely low, given the diversity of variables in the deposits and operating practices of the producers.

R&D Direction 4.5.2 – Reduced "Accessible" Resources – Motivation – Currently "accessible" resources are estimated based on including shallow in-situ production. If containment, or unexpected breakdown of containment barriers once they are contacted by steam, proves to be a serious environmental or recovery issue, then there could be a considerable reduction in the current estimation of reserves.

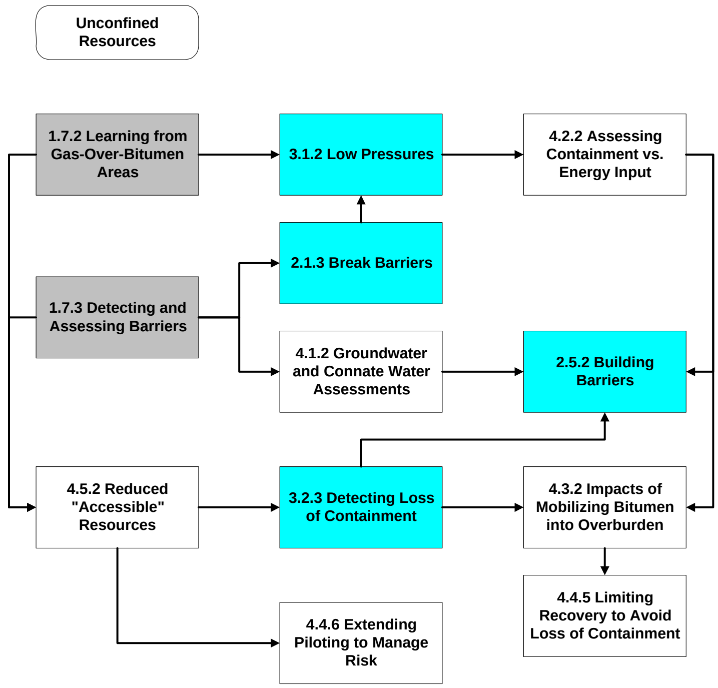


Figure 6.4 – Unconfined R&D Directions

7. Thin Oil sands

While thin oil sands deposits are a significant part of the total resource, an initial assessment would be that large-scale development of these areas will occur much later than other deposits, due to the lower quality and bitumen in place. However, there is potential for early development, by smaller producers if suitable, low cost technologies can be developed.

There is ultimate potential for these deposits to be developed in three different ways, depending on the geological situation: a) mined tunnels in the carbonate under the formation to increase effective payzone thickness, b) boreholes in the formation, instead of cased horizontal wells to enhance gravity drainage, or c) sub-surface mining. Generally development will need lower capital cost wells, facilities and greater portability of capital assets.

7.1. Description of Resource

As discussed earlier, thin oil sand deposits are extensive, and surround the central thick channel oil sands, which are being commercially developed. Thin oil sands represent one quarter of the total oil sands resource, using a 10 m thickness cutoff. With a less conservative cutoff of, for example, 25 m, the size of this undeveloped resource would be even larger.

Thin bitumen deposits are less attractive for SAGD operators, because they offer reduced economics and increased environmental footprints. The key factors are as follows:

- Thinner deposits contain less oil over the producing horizontal well.
- Thinner deposits result in a narrower steam chamber and therefore reduced well spacings. This increases capital costs and the environmental footprint on the surface.
- Thinner deposits will lose more heat to the over and under burden.

A related issue is the possible presence of shale or clay layers inside an oil sands deposit. A thick enough shale layer will effectively convert the deposit into two thinner deposits. SAGD is a gentle process, and is not considered to be capable of breaking thick shales, in the same manner as CSS. The thickness of shale layers that may be sufficient to stop the vertical expansion of a SAGD steam chamber is still the subject of investigation. SAGD impacts on shale barriers, is a double edged sword: it is desirable to break shales inside the oil sands deposit, while it is not desirable to break shales providing containment of the zone.

A view often presented, and supported by limited data from the UTF, is that thick shales are not likely to be laterally continuous. Most clay zones are discontinuous and would act more as a baffle than as a barrier. Therefore, thick shales would act as a baffle and would have the effect of reducing the final recovery factor. Thin shales, on the other hand, could be laterally continuous. However, the SAGD process, in time, would break down thinner shales. The net effect could be a reduced production rate and a poorer steam to oil ratio. There is also a view that the presence of thin shale zones would aid the development of the SAGD steam chamber. In clean sands, the steam chamber does not develop properly and grows in height too fast. The presence of a thin shale inter-layer delays the vertical growth of the chamber and allows it to develop horizontally.

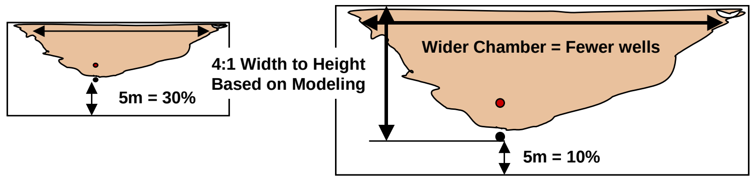


Figure 7.1 – Impacts of Zone Thickness on SAGD Recovery

7.2. Current Understanding of Limits – Small-Scale, Portable

Assuming that thin deposits might be developed with on-going evolution of SAGD, the main issues to address will be access costs. As the zone gets thinner more of the bitumen resource is lost to “buffer” zones left between the bottom of the producing well and the bottom of the formation. For example: Leaving a 5 m buffer in a 50 m thick zone only reduces resources accessed by 10%, while the same buffer in a 10-20 m thick zone would reduce access to 25-50% of the resource.

At the same time the theoretical development of SAGD chambers, assumed to be 4 times wider than they are high, would require 3 to 6 times more well pairs, on closer spacing; significantly increasing the costs to recover a lower percentage of the resource. Heat losses to over and under-burden may also be more significant and a wider area will have to be accessed to achieve the same production rates. With lower recoveries per deposit area, surface facilities will likely have to be portable to allow the capital cost to be shared over a larger area of the deposit, and to minimize pipeline distances.

7.3. Exploration – Assessing Outside the Sands

As discussed previously for unconfined resources (Section 6), options to develop thin deposits will be highly dependent on the properties, and containment, provided by the over and under-burden. Currently there is very little experience with thin zones, except in some thermal, conventional heavy oil operations in thin, deep Saskatchewan deposits, which have proven to be economically marginal with current practices and facilities, and in a resource that is already producible with primary methods.

R&D Direction 1.7.1 – Characterize Thin Deposit Properties – Data/Analysis - A first step is to gather more information on the distribution, geologic and geographical settings of the “thin” deposits. The resources must be assessed not only by thickness but also depth, properties of the under-burden and over-burden. Mining assisted, direct mining, and many other options, would be greatly assisted by having strong and relatively continuous layers above and below the oil sands.

R&D Direction 1.7.4 – Assessing How Thin is "Thin" – Investigation – A study to assess and test the limits of application of current in-situ processes would help to highlight the limits of existing technologies in thin zones. E.g. what is the minimum buffer layer needed in oil sands over various types of under burden (water sand or limestone) and some assessment of the relative strength of overburden materials.

7.4. Access – Sub-Surface Mining Assisted

In thick oil sands, sub-surface mining methods, such as those used in the coal industry, would face very significant challenges, as the oil sands itself is not strong enough to provide support for mine roofs and/or floors, and most methods, currently used in coal mining, cannot mine a 50m high face underground. However, as part of this study, we requested input from a number of experts in the area of sub-surface mining (See Appendix A2.2) and some methods, such as long-wall mining or borehole mining, may show promise, as either primary methods or methods to enhance some type of in-situ extraction. Long-wall mining uses a shield to protect the mining machinery that hydraulically advances as the ore is mined, allowing the overburden to collapse behind it. Borehole mining, used in uranium mining in Saskatchewan, uses water jets to hydraulically mine a cavern and removes the ore as a slurry, which could potentially be sent directly to a surface extraction process, while the overburden would collapse into the mined out area. An issue, with both of these particular options, would be to find areas for tailings storage, but they would have the advantage of potentially using surface extraction technologies that are still under development e.g. dry tailings.

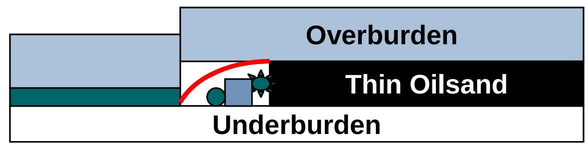


Figure 7.2 – Long-wall Mining in a Thin Oil sands

R&D Direction 2.3.2 – Sub-Surface Mining Options – Investigation – Long-wall and borehole mining should be investigated for use in a wide variety of ways. Both may be used directly to mine the oil sands for surface extraction. In areas where the underlying formation is the basal limestone a long-wall process might be viable and could be combined with some type of in-mine slurrying system, or with ore conveyors.

An advantage that in-situ operations have over mining operations is that most of the material is not handled directly and much of the problematic materials, such as clays, can potentially be left behind. A combination of mining methods to develop permeability channels, with the use of in-situ extraction may be more attractive than either would be on their own.

R&D Direction 2.5.6 – Sub-Surface Mining Assisted – Investigation – Various options are possible. Tunnels or boreholes could be mined in the underlying basal carbonate formation, as was done for the UTF but on a smaller scale, with wells or augered boreholes, from surface, intersecting the tunnels. The boreholes could be used for steam injection and/or production, which would avoid losses to a buffer zone, increase head for pumping produced fluids, and allow a large number of chambers to be developed from a central, larger-scale injection/production facility. Wells from surface could be sealed at the top of the oil sands but potentially with control and monitoring devices installed to control the process. Tunnels would not require manned operations underground once operations begin.

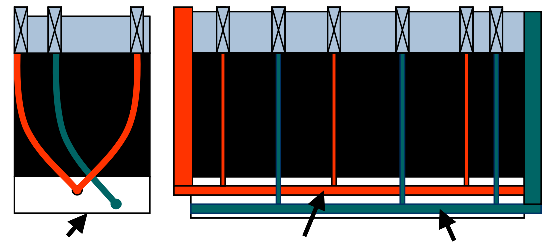


Figure 7.3 – Basal Carbonate Boreholes for Steam Distribution and Production Collection

7.5. Processes – Sub-surface Mining or Hybrids

Mining, or mining assisted methods, might remove 10-80% of the in-situ material as ore, which will require processing similar to existing surface mined ore, but on a smaller scale or using existing extraction facilities. To minimize surface extraction, this operation could be carried out in situ in the oil sands formation,[10] or in chambers created in the under-burden (basal carbonate – mined chambers or salt/potash solution mined caverns). Salt caverns are already used for storage of sand produced from primary CHOPS operations and allows increased oil recovery from the oil sludge, because of the long retention time. Most oil sands and heavy oil areas are underlain by either carbonates, evaporates or unconsolidated sands in which caverns might be constructed at relatively low cost.

R&D Direction 3.9.2 - In-situ Application of Surface Extraction Methods – Investigation – Formations, underlying bitumen or heavy oil deposits, should be assessed for potential to form underground extraction/sand storage facilities in areas of thin or isolated bitumen deposits.

7.6. Impacts on GHG and Sustainability – Last of the Sweet Spots

As indicated earlier, thin zone "Sweet Spots" may be developed before thicker deposits have been fully exploited. The main initial sweet spots identified could be accessed from highwalls at the edges of existing and future surface mines, where mining methods might be used to extend the resources accessed. The main barrier to this option is the lack of room in mine plans, for leaving any mined areas empty. As mined materials are significantly higher in volume than the original ore and overburden, and tailings ponds require very low angle slopes for stability, there is little opportunity to access highwall areas, before they are backfilled. Accessing thin, or thick but deeper, sweet spots from surface would be made more viable if new developments in tailings (dry tailings), or dyke building (use of sulphur concrete to reduce dyke volumes and slopes), were to be developed.

[10] Yildirim, Erdal – Suggested in-situ percolation extraction in a partially borehole mined formation. Mining base of formation would allow oil sands to dilate and collapse to improve recovery, while still leaving enough material to support the overburden.

R&D Direction 4.4.8 – Access from Surface Mining Potential – Investigation – Assess limits of highwall access and potential methods in current mining operations to identify the potential prize of reducing tailings and using more compact dyke structures in mine planning.

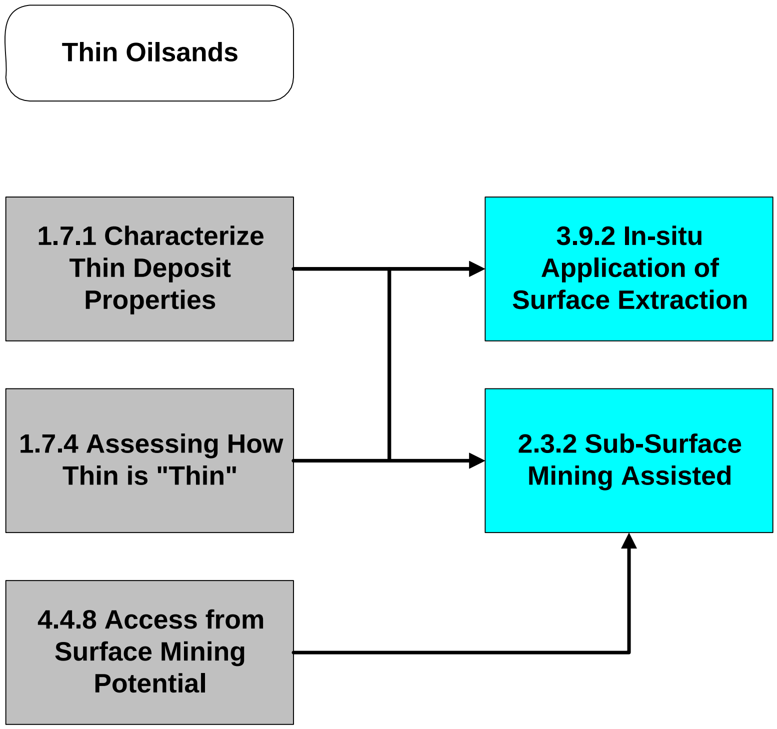


Figure 7.4 – Thin Oil Sands R&D Directions

8. Primary Heavy Oil and Bitumen Remaining Resources

Primary heavy oil and bitumen has already been covered to some degree by a previous PTAC report, on "Conventional Heavy Oil R&D Needs Including GHG Intensity Reduction". However, that report did not cover heavy oil and bitumen produced from oil sands leases. While the boundary between the Conventional Heavy Oil and Oil Sands deposits[11] implies a major difference in the resource, and how it is regulated, the primary production methods used in both areas are very similar. The ability to produce both bitumen, and heavy oil, by pumping alone, provides for a very economical method of production, with portable tanks, pumping systems and production transportation by truck. Development can be undertaken one well at a time, or in "pads" of 2-7 deviated or horizontal wells, so "mega-projects" are not required.

Many of the R&D Directions, listed below, are covered in the previous report. However, that report has a short-term focus, and the generally thicker, and richer, primary oil sands areas may be amenable to the use of technologies, which might not be feasible or economically viable in the conventional heavy oil region.

8.1. Description of Resource

Bitumen viscosity is not uniform across the Alberta oil sands. In some deposits, bitumen viscosity is low enough to allow cold primary production, using horizontal wells and does not always involve co-production of sand. Most of cold primary production of bitumen is from the Cold Lake area, northeast of Lloydminster. In Athabasca, cold production is found in the Wabasca and Brintnell areas, where water floods are being piloted in an effort to increase recovery factors. In Peace River, cold primary production is found in the Seal area.

In Cold Heavy Oil Production with Sand (CHOPS), as practiced in the Lloyminster area, sand production weakens the structural integrity of the reservoir, and may cause formation breakdown. While most of the other "inaccessible" resources have 0% recovery, the primary heavy oil and bitumen deposits are able to be produced to 5-10% recovery, due to a unique recovery process of foamy oil and sand production. Recoveries are still very low, and some wells in these areas never even reach 5% of the initial oil in place. This low oil recovery is the reason primary production areas are being considered in this study. Because of the uncertainties in understanding the production method, it is very difficult to assess how much of the total in-situ bitumen and heavy oil would be counted as "primary production reserves". As many in the industry have expressed: *"We understand it when it works, we don't understand it when it doesn't."*

8.2. Current Understanding of Limits – Wormhole Dynamics

As with conventional heavy oil, the primary insight, which has led to commercial primary production, has been the discovery that high oil/bitumen rates can be

[11] CHOPS - Cold Heavy Oil Production with Sand in the Canadian Heavy Oil Industry http://www.energy.gov.ab.ca/2856.asp. North of Township 53 line in Alberta production is defined as Oil Sands, while south of Township line 53 is heavy oil. In Saskatchewan, some "heavy oil" may actually be light or medium crude as grade is dependent on the main product being produced in an area.

achieved from some formations if the sand is allowed to enter the wellbore, and, be produced to surface. This results in the formation of “wormholes”, which can extend a significant distance from the well, and allow “foamy oil” to be produced with large amounts of sand, despite the high viscosities of bitumen at normal reservoir temperatures of 20-25° C. Not all bitumen formations are amenable to cold primary production. Recoveries of the resource are very low: 5-10% or less, and wells deplete relatively quickly. Production is sustained by continually drilling new locations, however, it is currently unclear how many new locations remain available for further drilling. Also, the development of wormholes may negatively affect follow-up production.

R&D Direction 1.9.1 – Cold Production Limits – Data/Analysis – It is not entirely clear how much of the in-situ oil sands resource is producible with primary methods. Some areas appear to “water out” very quickly, while other areas don’t appear to foam. It is also not clear how primary production impacts recovery from thick reservoirs. Greater work is needed to map and characterize areas of the deposits, which can be produced by primary means, their expected recoveries, and to make assessments of future production rates and volumes.

A significant area of uncertainty lies in assessing the conditions under which production from primary bitumen wells ends. Generally the production either ends in a “flood of water”, or gradually declines and stops flowing at economic rates. However, exactly where the water comes from is rarely assessed, as it is usually deemed more economic to drill another well rather than try and shut-off water in a producing well.

R&D Direction 1.10.4 – Defining the End State of Cold Production – Investigation – Understanding the end-state of the cold production phase is a key requirement for developing, assessing of implementing any type of follow-up process. The source of the water entering the producing well should be more broadly investigated and defined across the producing areas, as an indication of communication with other zones.

8.3. Exploration – Assessing an Altered Formation

Wormholes are seen as a key factor in any post-primary production of oil sands. Tests have shown that in some areas wormholes can extend many hundreds of meters, creating very high permeability channels between wells. Other indications are that wormhole formation is highly dependent on in-situ stresses and geomechanical factors in the reservoirs. If wormholes are stable, or can be stabilized, they could enhance performance of a number of in-situ processes, however, to maximize their use they must be well understood and mapped by some method.

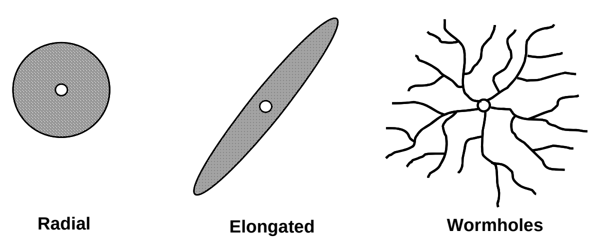


Figure 8.1 – Potential Sand Depletion Patterns (From C-FER Technologies Presentation)

R&D Direction 1.10.1 – Wormhole Dynamics and Properties – Investigation – A number of researchers have developed theories on wormhole formation and growth. However, it is difficult to assess the theories, in specific cases, as there is usually insufficient information from in-situ measurements and field operations. New, low-cost, methods of gathering information on reservoir geomechanical properties are required, along with higher quality field data on actual volumes of sand produced.

R&D Direction 1.10.3 – Locating Wormholes – Investigation – To understand wormholes, some method must be discovered to allow wormholes to be mapped without requiring extensive drilling. Passive, long-term monitoring of low energy signals from a number of locations in an area may provide a database, which could be empirically mined to infer wormhole growth, development and location.

R&D Direction 1.10.2 – Wormhole Stability Factors – Theory Development – Once wormholes can be found, monitoring methods are needed which can track their status in-situ, so that wormhole stability can be assessed. Methods may be similar to those suggested in Issue 1.10.3.

8.4. Access – Mitigating or Enhancing Wormhole Impacts

Besides impacting the understanding of properties of deposits where "worm-holing" occurs, wormholes also pose some challenges to drilling and completion. The assumption is that most wells used for primary production will be abandoned, and that new wells will be required for some follow-up enhanced recovery process. However, indications are that problems are encountered during infill drilling of wormholed reservoirs if the new well encounters a wormhole. In these cases well circulation can be lost and problems are encountered in cementing casing in the wells.

R&D Direction 2.1.4 – Drilling in Wormholed Reservoirs – Field Trials – Controlled and closely monitored drilling trials could be undertaken in depleted, wormholed reservoirs to test options such as underbalanced drilling, or wormhole plugging methods. New technology might also be tested, using profile control tools, to try and detect and avoid intersecting with wormholes when drilling horizontal wells.

R&D Direction 2.1.5 – Flexible Completions – Field Trials – New completion methods could also be tried to control cement placement by staging cement above the oil sands formation. This might also allow for more flexible methods of accessing the oil sands with multiple open holes, multiple coil tubing drilled mini-wells from a single casing, or use of underground mining methods such as augers and boreholes to generate larger disturbed areas in the oil sands formation.

New access methods could lead to new low energy extraction methods based on current surface extraction techniques.

R&D Direction 2.3.3 – Extraction Operations in Non-Surface Mines – Investigation – In deeper oil sands, the overlying strata are often stronger than those found in shallower formations. As sand production from CHOPS wells is already high, with many wells producing in excess of 1000 m3 of sand, it is already somewhat of a mining assisted operation. Intentionally mining the sand, in a controlled fashion, at the start of post-primary production may create chambers large enough to allow for in situ extraction chambers. (See Section 7.5)

R&D Direction 2.5.3 – Sand Removal and Storage Options – Investigation – Continuous sand production to lease tanks in primary operations leads to a continual need to clean sand and clays out of the tanks. Work is already underway to develop methods of producing sand, through pipelines to central batteries (analogous to hydrotransport of oil sands in surface mining operations) or in separating dry sand at individual wells or pads. Progress in this area could lead to improved sand management and disposal, which would enable higher sand removal rates and potential storage in subsurface evaporites.

8.5. Processes – Assessing a Wide Range of Options

Since the impact and properties of wormholes are still poorly understood, especially on a well-by-well or pool-by-pool basis, it is difficult to assess which of the many suggested post-primary recovery methods will work in these partially depleted deposits. Stable wormholes would tend to favor some type of follow-up steam, hot water or solvent flooding processes, which could take advantage of communication through the wormholes. However, some tests to date[12] seem to indicate that wormholes are unstable, and any process that reduces the viscosity of the bitumen "glue", binding the oil sands together, will cause the wormholes to collapse. This leaves either treating the wormholed reservoirs as though they are essentially the same as "inaccessible" deposits, or working to find someway to extend the low energy, low cost primary production, as the most viable options.

R&D Direction 3.6.1 – Controlling Wormhole Development – Field Trials – Since wormhole development seems to be impacted by in situ stresses and geomechanics, some researchers believe that wormhole growth might be controlled to optimize, and extend recovery. The key controlling factors appear to be operating practices in adjacent wells, which impact stresses, similar to lessons learned in thermal CSS operations, where well locations and steaming practices have evolved over the years to control where steam goes in the reservoirs. This requires pool wide analysis, and collection of better field data, to allow analysis and optimization, rather than operating all wells as independent entities.

R&D Direction 3.6.2 – Water Shut-off – Field Trials – Water production can severely limit recovery and increase energy costs in primary operations. It takes more energy to produce, treat and dispose of water than it does to produce oil. More effort is required to determine: a) where the water is coming from, as that influences what type of water shut-off is needed; and, b) low cost methods of shutting the water off, which might include wax treatments, sulphur or gel blocking agents.

[12] C-FER presented materials for the CHO R&D Needs Including GHG Intensity Reduction workshop and report, which indicated that when steam was injected into a primary well in Elk Point it communicated rapidly with another well some distance away, but the communication path was lost after only a few hours.

R&D Direction 3.6.3 – Plugging Wormholes – Field Trials – Wormholes can only continue to grow if the pressure in the reservoir can be lowered with pumping. Influxes of gas from small gas pockets or water, through wormholes, or lost containment, can make it difficult to depressure the well, or may cause the oil to expand into where the gas or water is coming from. Plugging wormholes may allow primary production to continue and encourage the formation of new wormholes to access more of the reservoir. A number of plugging methods have been proposed which require controlled field trials.

Wormholes are an indication of how easily the formation can be broken down in-situ, as a result of fluid flow. Borehole mining methods potentially could be used to build on this further, by generating boreholes at right angles to the natural orientation of wormholes, which may allow greater wormhole development.

R&D Direction 3.1.5 – Borehole Extraction – Investigation – Generating large diameter, uncased boreholes on the top and bottom of the formations, with injection and production tubing, may allow for controlled in-situ, hot water extraction in thick wormholed reservoirs. Collapse and dilation of the formation into lower boreholes would allow for percolation extraction, by feeding warm water, or steam, into the lower part of the reservoir and collecting produced oil and water at the top (i.e. an inverted, pressurized SAGD).

Even if wormholes collapse, preventing any sort of drive recovery method, they still provide areas of increase permeability to allow steam or other injectants to access a larger portion of the reservoir. Huff-and-puff processes may be able to take advantage of this reservoir state.

R&D Direction 3.1.4 – Thermal Steam/Water and Wormholes – Field Trials – Portable compact direct contact steam generators could be used for periodic stimulation of wells to avoid large sunk capital costs. Annual or biannual treatments may allow production to continue at fairly low cost and low energy intensity.

R&D Direction 3.5.1 – Solvents and Wormholes – Field Trials – Similar to thermal options, periodic treatments with solvents may allow primary production to continue without moving to a full-scale EOR process.

8.6. Impacts on GHG and Sustainability – Using Infrastructure

A major driver to develop post-primary production options is to take advantage of infrastructure such as batteries, pipelines, roads, support industries and communities, which have grown considerably over the last decade, in primary production areas. As well, the current primary operations, aside from the practices of venting produced gas and trucking production, has relatively low energy intensity, and is rapidly becoming much less GHG intensive as provincial regulators encourage gas conservation and increased pipelining in primary production areas. Many of the R&D directions are near-term and were covered in PTAC's Conventional Heavy Oil R&D Needs Report (August, 2005).

R&D Direction 4.4.7 – Utilization of Primary Infrastructure – Investigation – A sustainability study should be undertaken to determine the economic, environmental and social costs if existing infrastructure in primary production areas (such as Bonnyville, Ft. Kent, Elk Point, Cold Lake and Lloydminster) is lost prior to implementation of post-primary methods. This could be a significant driver for accelerating R&D for this resource.

R&D Direction 4.5.3 – Risk Assessment Post-Primary Processes – Investigation – The lack of understanding of the condition of post-primary production deposits adds risks to later development. A key concern might be potential loss of caprock integrity due to sand production, which could lead to losses of post-primary injectants, or short-circuiting of injectants between wells through unpredictable wormhole behavior.

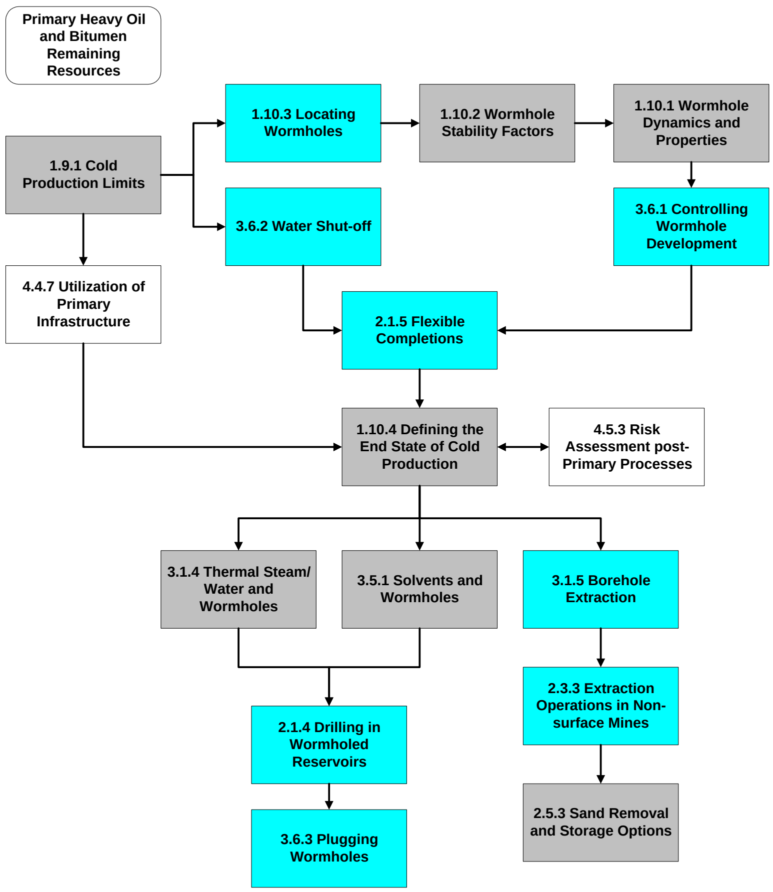


Figure 8.2 - Primary Heavy Oil/Bitumen R&D Directions

9. Small Surface Deposits

While most of the large oil sands deposits are continuous, there is evidence for isolated oil sands deposits in Saskatchewan[13], which may be developed at some point in the future. These of deposits may not be a high priority in Alberta, or with major oil sands producers. However, they may be a niche opportunity, which might be supported by the Saskatchewan government and smaller producers, who can't afford to participate in larger developments. Initially there is too little known to assess many specific R&D needs except those already outlined for other shallow, thin oil sands deposits.

9.1. Description of Resource

9.1.1. Saskatchewan

Most of the small surface deposits of interest to this study are extremely undefined, and are mainly focused on deposits in Saskatchewan. Bitumen deposits have been observed in two areas of Saskatchewan:

- The Clearwater valley, which is east of Athabasca; and,
- The Peter Pond and Churchill Lake area, which is north east of Cold Lake.

The observations have been from surface samples and from several of the wells drilled in the area. The information is found in geological reports dating back to 1954 and 1978. While the amount of data is small, the quantities of oil sands were deemed at the time to be uneconomic, as were most other oil sands deposits being assessed at that time. However, drilling has left large tracks of land unexplored, and it is still possible that oil sands deposits of economic size and quality could be found.

Clearwater Valley: Clear outcrops of the McMurray formation are visible along the Clearwater valley. These outcrops range from 3 to 23 m in height and are locally saturated with bitumen in the lower outcropping sections. These bitumen-bearing sands are located near the Alberta border, 9 to 24 km west of Contact Rapids, which is in Township 89 R22W3.

One company, Oilsands Quest, is presently conducting delineation drilling in the area immediately east of Suncor's Firebag Project, on the Saskatchewan side of the border. The company is drilling a 25 core-hole winter program and is reporting encouraging results. Phase 2 would be a 150 core-hole program. Oilsands Quest is estimating the volume of oil sands in northwestern Saskatchewan, at 50 billion m3 (300 billion bbls), although other reports[14] estimate volumes as low as 10 billion m3 (60 billion bbls) for all of northwest Saskatchewan.

[13] Oil & Gas Inquirer Report March 2006 Page 42 "Oil sands Quest reports positive initial drilling results from exploration program in Saskatchewan" Reported 5-27 m of McMurray formation pay with average oil saturations averaging 15% in 6 of 7 delineation wells drilled to date.
[14] Daily Oil Bulletin Article dated April 10, 2006.

Peter Pond Lake: Bituminous sands are present in the till in the southern part of the Peter Pond Lake area. This deposit was analyzed in 1954 and found to be physically similar to oil sands from the McMurray formation in Alberta. It is postulated that glacial erosion would have allowed glacial ice to physically transport this deposit from the Fort McMurray area, 50 km south southeast to the Peter Pond Lake area in Saskatchewan. This assessment was based on the fact that the oil sands materials were very similar to those in Alberta, but the underlying strata was considerably different from other oil sands deposits, and not consistent with the oil sands deposits forming in their current locations.

9.1.2. Alberta

The Athabasca deposits that were chosen for the first oil sand mines were those where the deposits were thick, rich and laterally continuous over a wide area. These factors favored project economics. The AEUB estimates the size of small fragmented surface mineable oil sands at 10% of the surface mineable volume. Therefore, small fragmented surface deposits represent approximately 900 million m^3 or 0.3% of the total oil sands resource.

9.2. Current Understanding of Limits – Limited Data

There is not enough data on this area because little work has been done since the 1970's, and most of the detailed information and cores from previous assessments have been lost. This should be re-evaluated at a later date when more is known.

9.3. Exploration – Getting Started

The main need is to determine the extent and characteristics of the smaller deposits. There may be other small deposits that could also be investigated in this relatively undeveloped and under-explored region.

R&D Direction 1.4.1 – Drill/Core Potential Sites – Investigation – Private exploration could be supplemented by geological surveys to determine if there are other potential deposits in the region, especially in Saskatchewan. The focus should be on McMurray or Clearwater formations that may not have been identified. The Clearwater on the Saskatchewan side of the Cold Lake Air Weapons Range might be assessed for bitumen as an extension of the formation on the Alberta side.

9.4. Access – Small Pit vs. Sub-Surface Mining

Assuming the deposits are shallow enough to surface mine, they may not support large infrastructure. Therefore, at some point, development will come down to a decision on whether or not a small surface pit, or some type of sub-surface mining method are justified.

9.5. Processes – Small Scale Extraction Options

Small scale extraction methods, such as the Taciuk processor or other processes that have been studied but rejected for use in large scale operations, may be viable on a smaller scale.

9.6. Impacts on GHG and Sustainability – Niche for Small Players

Small isolated deposits provide a potential niche for small, low overhead developers.

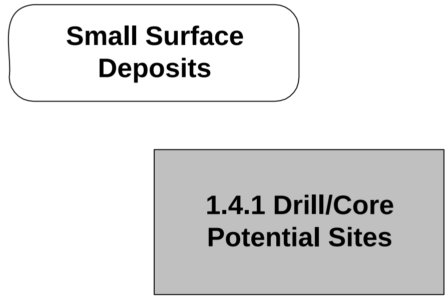


Figure 9.1 – Small Surface Deposits R&D Directions

10. Deposits Under Tailings

Some mine plans include options for relocating tailings to mined-out areas by the end of the pit life, while others currently do not include accessing oil sands under tailings. Ultimately, economics will likely drive this decision, especially if a reclamation method is developed for fine tailings, which could lead to the tailings ponds being reprocessed. As this appears to affect a relatively small, subset of the mineable resource base, the potential for developing any new technology specifically for this resource is small.

10.1. Description of Resource

Planning oil sands mining operations is much more difficult than planning coal mines, as the deposits are so vast and, after bitumen extraction; the volume of waste material and tailings is much larger than the volume of the original ore. As a result, the final landscape is higher than the original surface. Current extraction methods result in the formation of a large volume of fine tailings, consisting of water and clay that do not separate. The fine tailings, therefore, have to be stored for long periods of time. Often the lease layout and mine plan to optimize resource access, make it necessary to locate tailings ponds on top of relatively high quality oil sands deposits. If the tailings cannot be relocated to allow mining, then some volume of the resource will be lost.

10.2. Current Understanding of Limits – Pond Integrity #1

The main sustainability limit, which must be considered in any attempt to access oil sands under tailings ponds, is to always minimize any potential for a catastrophic loss of tailings containment. The determining economic limit for tailings is generally the cost of building dykes and handling materials each time they are moved. As the volumes of tailings and waste materials is considerably higher than the original volumes of oil sands (both from dilation and water content of fine tailings), the incremental costs involved in moving established tailings areas are also large.

Figure 10.1 – Existing Oil sands Tailings Ponds Located Adjacent to and Above the Athabasca River (left side of photo)

10.3. Exploration – A Known Quantity

Data should be available from current and proposed mine plans to allow an estimation of the volume of oil sands potentially sterilized by tailings ponds, as well as estimates of the factors which would lead to their exploitation with standard surface mining techniques.

R&D Direction 1.5.1 – Potential Losses from Current Plans – Investigation – Potential losses of oil sands resources under tailings ponds should be tabulated and tracked to allow continuous reassessment of the value of tailings reclamation.

10.4. Access – Timing vs. Technology

Accessing oil sands in tailings areas is potentially more a matter of timing than technology. Key timing factors impacting access will be: a) timing of development and availability of fine tailings reclamation vs. the timing of mine closure; b) bitumen prices at the time of exhaustion of easier-to-mine, non-tailings areas; c) timing of developments near an existing tailings pond that may allow synergies for moving and mining the oil sands under the tailings.

A potential alternate method for long-term storage of tailings may be to backfill depleted SAGD or other in-situ deposits, 20-30 years from now. While in-situ storage puts the tailings in potential contact with ground water, there would be less potential for a catastrophic release into surface waters, which would be much more devastating than chronic leaching effects. Potentially freeze walls, buffer zones of bitumen, or other means could help to ensure underground containment integrity, and allow for surface mining in the existing tailings pond areas.

10.5. Processes Surface or In-situ

If access to tailings ore bodies is not possible through surface mining, or alternate disposal of fine tailings, then the potential exists for using shallow in-situ methods once they have been demonstrated in other deposits, and once they can be reliably controlled to ensure operations do not compromise the containment of the tailings. Water and tailings in the ponds will increase the pressure on the in-situ formation, which may impact dynamics of recovery, but may be difficult to research at this point.

10.6. Impacts on GHG and Sustainability – Resource vs. Risks

A key driver to recovering bitumen under the tailings ponds is the eventual final disposition of the tailings ponds. This has been covered in previous oil sands roadmaps, with the exception of assessing the potential for storage in depleted in-situ operations, and the potential for in-situ development. These options should be reassessed once final tailings reclamation plans are being discussed, so that the resource is not sterilized.

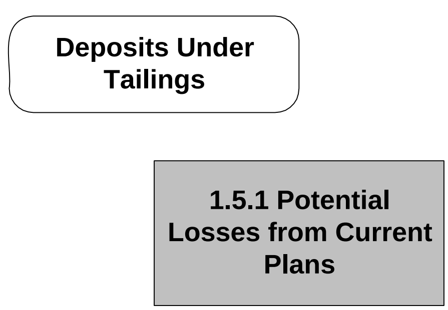


Figure 10.2 – Deposits Under Tailings R&D Directions

11. Exploration Support Technology

Exploration R&D Directions, specific to certain deposits, have been included in the previous section. However, there are other directions that would assist all sectors in assessing longer-term needs and potential alternative processes. Many of the barriers to providing the required support are systemic, in that oil sands developments are highly competitive, and chronic manpower shortages, during rapid development, make it difficult to put a priority on supporting technology, which is not immediately needed.

11.1. Need for Data

In some new deposits, which might soon be put under development, there has often not been a formal assessment, in advance of a new project development, of what data the government or reservoir engineers, might need to assess production performance. For example, it is becoming more obvious that measurement of sand production from primary cold production wells may be key data in assessing post-primary recovery options. However, sand production is insignificant and unimportant in conventional oil and gas areas, and does not constitute a revenue stream. Therefore, it is not required data for regulatory reporting. With oil sands and bitumen in carbonates developments, there will likely be a need to gather data on more than just oil, water and gas volumes, since many of the proposed processes involve chemical reactions (in-situ upgrading, combustion, or CO2 reactions with carbonates) and oil sands results may be highly impacted by drilling methods, completions, operating practices and sand production.

While no specific R&D need is suggested in this area, and little might be supported, some process should be developed, by government regulators and industry, to generate a flexible, adaptable and user-friendly method of collecting any type of data that may be identified as being significant, or potentially significant, to improving recovery. Data collection should focus on enabling, and ensuring optimum resource recovery, rather than simply gathering information on activity levels and production reporting for revenue calculations.

11.2. Key Types of Data Needed

Data needs span the full range of R&D efforts, from basic fluid properties from lab analysis, to reservoir properties from coring and seismic activities, to detailed information on how each operation was developed, maintained and operated. In exploration, key types of data need to be better defined, but based on a wide range of potential recovery methods.

R&D Direction 1.2.1 – Potential Impacts of Properties on Recovery – Motivation – A comprehensive list of deposit properties, which may impact recovery methods, needs to be developed and organized in a way that is supported by recovery theories and which will provide sufficient justification for producers or others to collect that information.

11.3. Cost Effective Quality Resource Data Collection

Because data collection may not be currently required for regulatory reporting, or immediate operational needs, the collection must be done in a way that is extremely cost effective, while providing a wide range and a large volume of data. Ideally, work indicated in 11.2 will identify some key factors which will be useful for many purposes, and which can be easily collected through low-cost, non-intrusive, low person-power, methods with consistent, reliable and rapid upload of data to a central database. In many cases, it may be more important to ensure consistency in data collection, so that trends can be observed, rather than absolute accuracy.

11.4. Assessment of Current Methodologies

The conventional oil and gas industry, as well as mining and minerals industries, have already developed a wide range of tools and methodologies for exploration and monitoring of oil and gas deposits, which are gradually being applied to bitumen resources. A key challenge will be to determine which of these tools and methods can provide the most valuable information, at the lowest cost.

R&D Direction 1.2.2 – Current Tools for Assessing Deposits – Investigation/Field Trials – A well-planned and controlled investigation of tools should be started to facilitate collaborative assessment and learning from the use of exploration tools in bitumen deposits. Vendors of some tools may have very little knowledge of oil sands or bitumen in carbonates, so the testing should be directed at specific properties over a broad range of geologic environments.

R&D Direction 1.2.5 – Numerical Modeling – Investigation – Classical empirical models have been developed for thermal and other recovery methods. However, in most cases, there is a lack of calibration of the models against actual production data. R&D to improve and validate empirical numerical models, using real field data is an on-going need and it also needs to be continually reassessed as more and high quality data is gathered.

11.5. Development of New Methodologies

While service and supply companies are providing a broader range of tools, than ever before for exploration, more effort is needed in finding new tools which can provide continuous monitoring of operations to detect potentially small factors which might impact reservoir performance. E.g. drilling and completion practice may impact the breaking down of weak internal reservoir barriers to flow, or production practices may increase or decrease the tendency for wormholes to develop.

R&D Direction 1.2.3 – Propose Potential New Tools – Theory Development – A back to basics approach may be needed to assess how occurrences in the reservoir, such as steam movement or wormhole growth, might be detected from a large database of static low energy signals, such as geoacoustic, microseismic or tiltmeter readings from static arrays.

R&D Direction 1.2.6 – Geostatistical, Geomechanical and Geochemical Modeling – Theory Development/Investigation - Modeling needs to be expanded greatly to allow a wide variety of processes to be modeled on a comparative basis.

Geostatistics, geomechanical and geochemical modeling are three areas for which more data and theory development are required to allow modeling of reservoirs. Models are needed which can predict changes in performance with the wide range of reversible and irreversible changes which development might cause to occur.

11.6. Supporting Development

Ultimately all these technology development areas must be brought together and assessed to determine if the predictions match reality. In the case of oil sands deposits, there is a unique opportunity, in the mining areas, to conduct research on tools and models, and then to dig down and verify what actually is in place or what happened after a given process was applied.

R&D Direction 1.2.4 - Compare Tools vs. Actual – Field Trials/Piloting – The ability to conduct trials in undeveloped, mineable areas should be capitalized on to conduct trials, allow follow-up investigation to assess results, and calibrate the exploration tools for oil sands. While this type of site specific activity would not be considered viable for any conventional oil pool, for the vast and unique oil sands it would contribute greatly to increased understanding, recovery and logical development of the resource

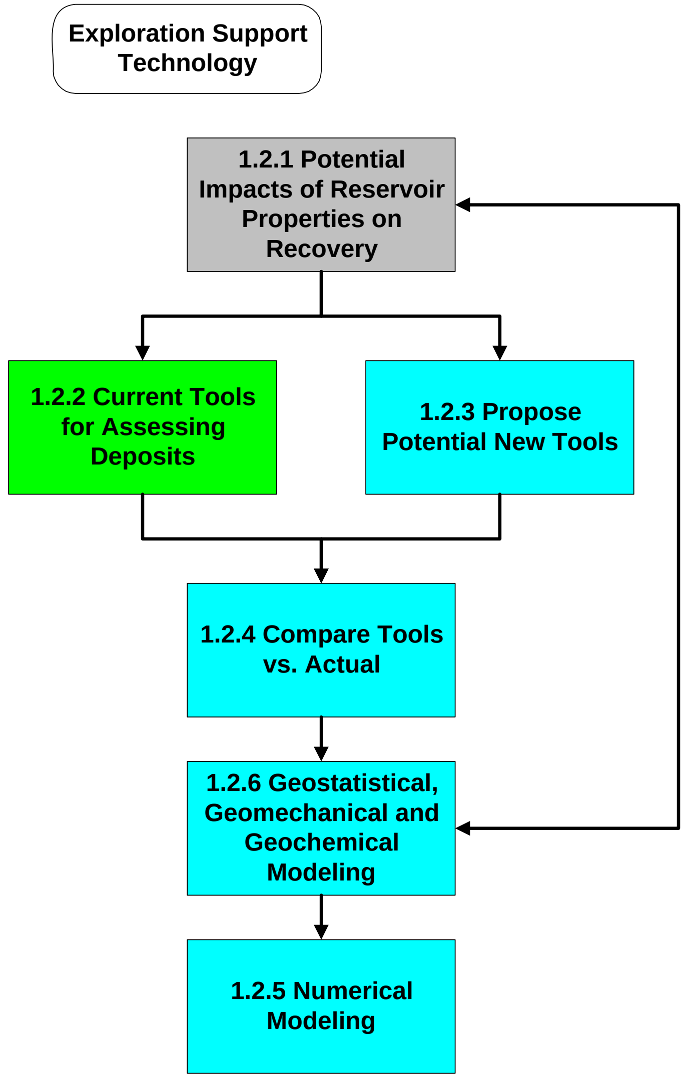


Figure 11.1 – Exploration Support R&D Directions

12. Access Support Technology

Alternative access methods show potential to reduce costs, energy use, and development footprints for many of the bitumen deposits. The main focus is to increase the quality of access to a larger volume of the resource base. Increasing the understanding and use of overburden and underburden zones, while minimizing materials handling, is a key to improving access in "inaccessible" areas.

12.1. Matching Problems with Existing Technology

Many of the existing problems with oil sands development, and accessing carbonates, should be solvable with existing technologies such as underbalanced drilling and experience from drilling in limestone/carbonate formations worldwide. Matching the problems with the appropriate technology, however, takes engineering/geologic effort to study and optimize the methods used. So, addressing this issue is mainly a challenge in resourcing and staffing in order to dedicate adequate effort to transferring existing technology into knowledgeable practice in the bitumen deposits.

12.2. Adapting Methods and Knowledge from Other Sectors

Another broad area of endeavor is to continue to investigate access methods used in other sectors, such as coal mining, uranium mining, placer gold mining and limestone mining/quarrying to allow adaptation of new methods to address new deposits, where currently used methods are, or become, uneconomic. Focus should mainly be on methods applied to unconsolidated or limestone deposits.

R&D Direction 2.2.1 – Tailings Solution Leads to New Options - Motivation – There are a number of methods, which might be applied at the edges of surface mining operations, which are hindered by the on-going issue of tailings storage and the large volumes of material which must be stored. This puts pressure on mining operations to quickly back-fill mined areas, and provides minimum opportunities for highwall access. Resolving the tailings issue would open up short-term opportunities to access intermediate and thin ore deposits adjacent to mining operations. A study quantifying these lost opportunities might accelerate efforts to implement tailings solutions, prior to final mine reclamation.

R&D Direction 2.1.6 – Adapting Pipeline Drilling Methods – Investigation – Low cost and small footprint pipeline drilling technologies might be suitable for providing access to many shallow, intermediate and thin deposits. These methods have been developed for use at high angles in highly variable surface strata and could be adapted to provide additional access to shallow deposits.

R&D Direction 2.3.4 – Adapting Mining Methods – Investigation – A number of existing mining methods, such as highwall, long wall and borehole mining have been suggested, many of which are used successfully in other types of deposits. Finding deposits with similar mining characteristics to oil sands should be undertaken. For example, uranium mining uses borehole mining methods, and generates a high percentage of mining waste to resource recovery, which requires long-term storage and reclamation. Mining offers high resource recoveries with potential for lower energy intensities, and many mining methods might be more viable to assist in-situ methods than as stand alone operations.

12.3. Focusing Efforts on New Technologies

A number of new and novel mining methods have been suggested which might be developed for increased access to more of the resource. As with exploration support technologies, the oil sands deposits are large enough in extent to justify the development of new technologies specifically developed for the oil sands.

R&D Direction 2.5.4 – Use of Zones Outside the Oil Sands for Access – Investigation – One common area of investigation for access, is to break out of the oil industry paradigm of only focusing on the “pay zone”. The Underground Test Facility (UTF) has demonstrated that there are potential gains to be made by thinking outside the pay zone. The oil sands are difficult to drill and mine because of their thickness, lack of solid overburden and the relative fragility of the oil sands matrix. Bitumen in carbonates has similar issues in the pay zone. Therefore, using other zones to access the pay zones needs to be investigated to a greater degree.

12.4. Trials of In-situ Construction Methods

As indicated in earlier sections, building low cost barriers, in-situ will be a key R&D direction for “uncontained” resources, but may also prove to be a critical need for other shallow in-situ deposits being produced with SAGD, solvents or in-situ reactions. Developing and proving containment methods will take a considerable amount of time, as it will likely take some time to determine if a constructed barrier has been successfully placed, with adequate integrity to prevent flows of fluids. There are also a wide range of potential near-term uses for these methods, such as freeze-walls to limit ground water impacts, or reduce mine dewatering costs, which could be opportunities to develop and test the methods to meet the future needs.

R&D Direction 2.5.5 – Trials of In-situ Construction Methods – Field Trials – Use of freeze-walls to limit ground water contamination from sulphur, tailings or other sustainability concerns, or their use to reduce mine dewatering costs, is an ideal area to develop methods for future development of uncontained areas.

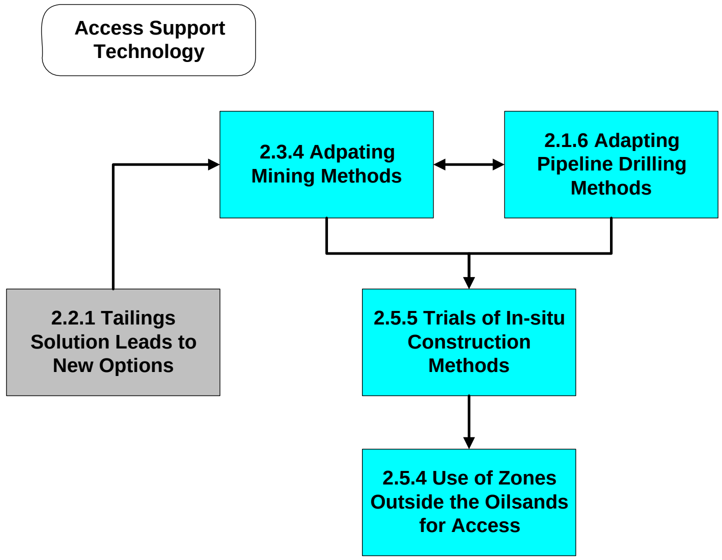


Figure 12.1 – Access Support R&D Directions

13. Process Support Technology

From a process support point of view, a major opportunity is to integrate work being undertaken by many diverse groups, with varying objectives and timelines, and try to pull the results together into a rational and optimized approach to improve all oil sands and carbonate recovery processes. Commonalities between the various deposits are growing. Yet, often information is not adequately transferred. E.g.: transferring upgrading research to in-situ reactions, carbonate reactions for flue gas clean-up vs. in-situ interactions, hydrotransport in mining operations vs. sand transport in primary bitumen and oil sands.

In GHG related issues, there are significant commonalities in the fact that water and steam are used for mining extraction, SAGD, CSS, primary production, and likely for pre-heating formations for more exotic processes. Therefore, improvements in produced water treatment, reduced fresh water use, improved thermal efficiency, lower cost energy sources (e.g. geothermal), etc are required for all deposit types. As indicated in Section 2, these are already major issues for current commercial developments, but will become even more critical in development of lower quality or more problematic resources.

Significant effort is needed to learn from past efforts, adapt to new situations and expand into future resource exploitation.

13.1. Past Field Trials – Hindcast Results Analysis

Oil sands and heavy oil research has been underway for many years, but reached a peak of effort in the 1970's and 1980's, mainly through efforts initiated though the Alberta Oil Sands Technology and Research Authority (AOSTRA), after its formation in 1974. AOSTRA funding helped to support a wide variety and a large number of field trials between 1976 and 1990. With the wind-down of AOSTRA in the 1990's, much of the information from these pilots, has been filed away but is not easily accessible. These pilots helped test processes and led to the eventual focus on and development of the SAGD process, which is currently considered to be the base case extraction process for in-situ operations. While key aspects of these pilots may have entered the public domain, through scientific papers and presentations, there is a lot of additional detail in these, and other past efforts, which can be mined for new learnings, in light of the increased knowledge that has been developed in the intervening years.

R&D Direction 3.0.1 – Past Field Trial – Hindcast Analysis – Investigation – A greater and more focused effort needs to be placed in mining past work. Control of AOSTRA materials has passed to Alberta Science and Research Authority (ASRA). However, considerable effort is needed to make these documents more accessible to a broader range of researchers, inventors, entrepreneurs and producers. Information on drilling and producing from the carbonate pilots, and experience in mining limestone in the UTF pilot may now be of more value to further development than the results of the recovery processes being piloted.

13.2. Assessing Related International R&D

While Alberta and Canada are in possession of a vast resource, bitumen, extra heavy oil and heavy oil are produced in many other regions of the world. In some cases, this development is more advanced than in Canada because the deposits are easier to access, deeper and/or less viscous. This experience and knowledge forms a significant body of alternate approaches and new ideas that should be more deeply explored for insights, which might be useful for our "inaccessible" resources, but were previously ignored because they were not suitable for use in our "accessible deposit" sweet spots.

R&D Direction 3.0.2 – Assessing Related International R&D – Investigation – Past presentations and discussions held through the United Nations Institute for Training and Research (UNITAR) International Conferences on Heavy Crude and Tar Sands, include many ideas and concepts, which were too numerous to review in this roadmap study, but may contain valuable information and insights applicable to the "inaccessible" resources, and need focused review by researchers with an eye on the unique characteristics of the future resource base.

13.3. Document Basic Principles – Thermodynamics, Heat/Mass Transfer & Physics

While much of the past R&D efforts have focused on specific chemical, thermodynamic, heat and mass transfer, and materials properties of oil sands, there is still much of the work in the laboratory that is unconfirmed, non-repeatable, or poorly supported by theory or field results. This divergence of theoretical from actual performance, highlights the basic need to further expand research into basic principles, to generate a better understanding of recovery processes. Factors such as irreversible changes in bitumen properties as it is mobilized, understanding mixing dynamics of solvents with solid bitumen in sand or rock matrices, and improved understanding of chemical, heat and energy interaction mechanisms in the reservoir environment, need additional efforts utilizing the latest analytical technologies, in conjunction with realistic physical models and field trials. Until the basic principles are fully understood, optimization and prediction for new processes, in new deposits, will be entirely based on empirical, trial and error, which is extremely manpower and resource intensive.

R&D Direction 1.3.2 – Surface Extraction Learnings → In-situ – Theory Development – The University of Alberta and others have been doing extensive work on oil sands surface extraction, supported by the oil sands mining industry. However, less funding and effort has been directed at moving this growing body of knowledge into use for the much larger in-situ resource and in-situ, thermal and non-thermal processes.

R&D Direction 1.3.3 – Surface Upgrading Learnings → In-situ – Theory Development – Surface upgrading has enjoyed a great deal of support, as an extension of refining technologies from the petroleum refining industry. However, moving upgrading in-situ presents numerous potential advantages, balanced by a large number of challenges. Processes and catalysts optimized for surface processing are unlikely to be suitable for in-situ processes. Therefore effort and funding is needed to develop capabilities, which can adapt to the in-situ environment where control of the process is much less rigorous than is the norm in surface operations.

R&D Direction 3.0.3 – Basic Thermodynamic, Heat and Mass Transfer – Investigation - Greater overall support and direction is required for research on basic principles, especially in the development and demonstration of larger and more realistic physical models than those currently used. It also requires greater access to and use of bitumen in its natural state and environment, rather than reconstructed or artificially manufactured samples.

13.4. Staged Recovery Methods

Much of the research and piloting to date has focused on trials of recovery methods as an initial application for bitumen recovery. Yet many processes, which might prove unsuccessful when applied to cold, solid oil sands deposits, may have merit later in the recovery process. Just as conventional oil producers do not normally start with water floods, or EOR operations, as soon as a well starts producing, many oil sands processes will not be able to economically compete with CSS or SAGD, which are proven, and more or less predictable in the early years of a project. Options, such as direct contact steam generation (Section 5.5), may help to improve efficiency and reduce emissions from initial thermal operations, but other methods such as in-situ upgrading (Section 7.5) are unlikely to be applicable in solid in-situ oil sands. Most non-thermal processes currently proposed usually have a thermal pre-heat or thermal assist process built in. In practice, then, it is likely that oil sands production, in all deposits, will be staged with specific methods and technologies optimally applicable at different points in the project's development. An example of a potential staged development is described in the following illustrations, which is only of one of many potential development scenarios.

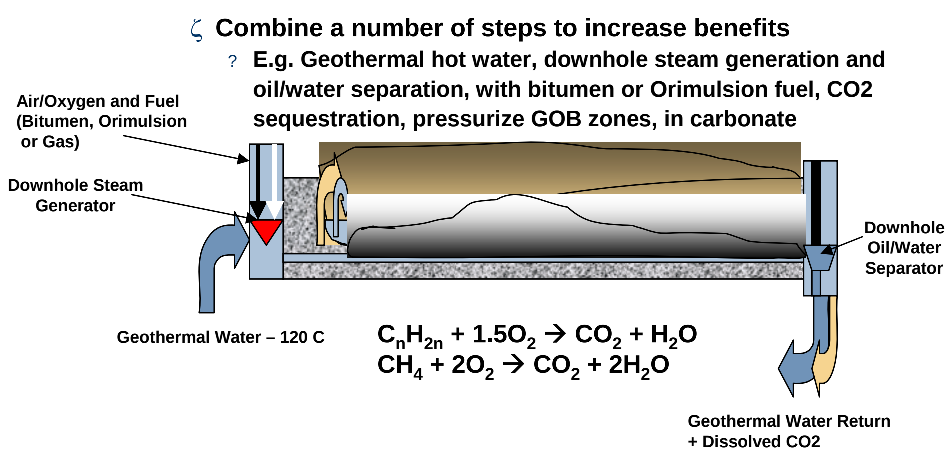


Figure 13.1 – Initial Thermal Stage

- Stage 2 – Convert to In-situ Combustion or Upgrading
  - E.g. air injection with catalyst to lower conversion temperature. Produce lighter products

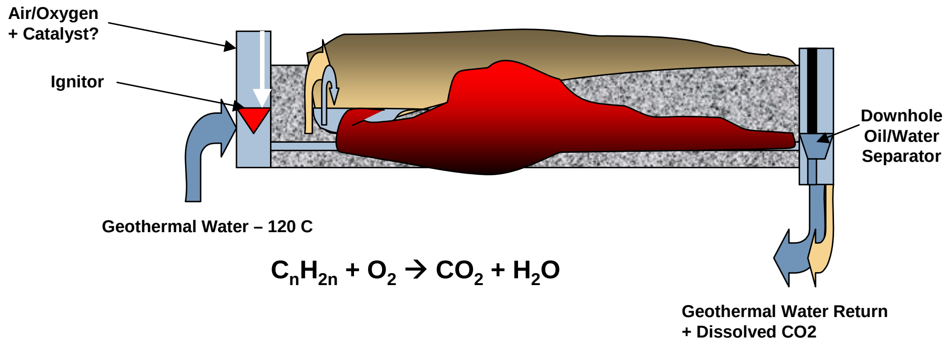


Figure 13.2 – In-Situ Combustion/Reaction Stage

- Stage 3 – Convert to In-situ Power Generation
  - E.g. air injection with catalyst to lower conversion temperature. Produce Electrical Power and cool formation

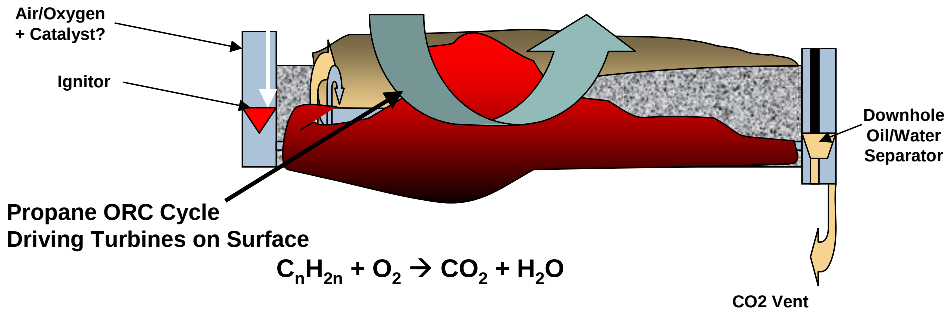


Figure 13.3 – Heat Recovery Stage

- Stage 4 – Bioconversion of residuals
  - E.g. inject warm water with nutrients and bacteria for slow conversion of remaining hydrocarbons to biogas

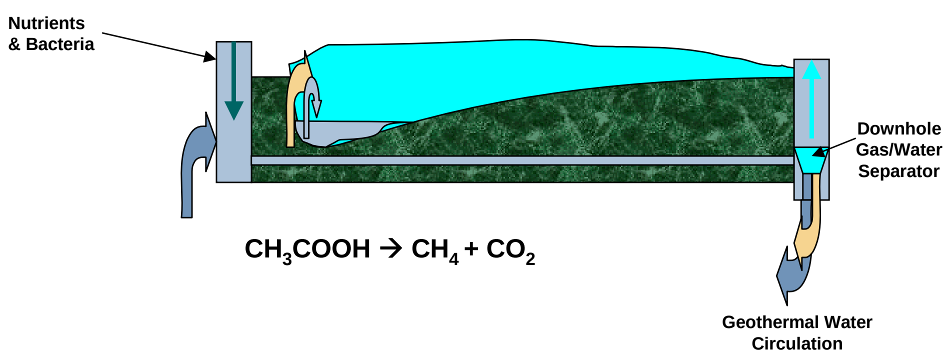


Figure 13.4 – Biorecovery Stage

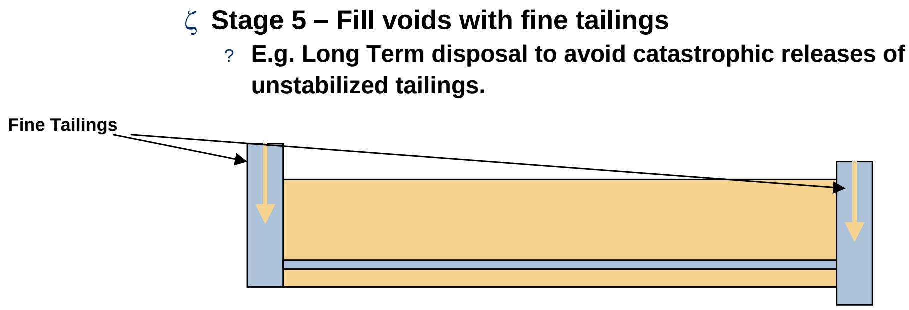


Figure 13.5 – Final Stabilized Landform Stage

R&D Direction 3.0.4 – Stage Recovery Methods – Investigation/Motivation – To optimize near-term activities, and development for the long-term, it is required to develop strategies that will have the greatest potential for achieving maximum recovery and benefit. Optimization of only the first stage of development may lead to significantly lower ultimate recovery of the resources. To address this, researchers, regulators and others, should be encouraged to develop long-range development "scenarios", which consider optimum timing and conversion from one process to a new process more suitable for a later stage of development.

13.5. Quality of Output Oil and Bitumen

In the timeframe of this study, looking at developing the unconventional resources in timeframes beyond 30-40 years, it is likely that changes in feedstock, and potentially changes in future fuel demand will require, or enable, changes in output production quality from oil sands operations. Options might be to consider impacts of blending streams, making gradual shifts in feed and processes, or developing totally new upgrading stages in-situ, or upstream of surface upgraders. Variations in produced hydrocarbon quality from oil sands will lead to a need to continually reassess the potential downstream impacts of each product stream. Currently downstream upgraders and refineries are designed to optimize the production of the highest value petroleum products; however, it is likely that refiners in future will develop greater flexibility to accept a wider mix of feedstocks, which will allow optimization of the whole hydrocarbon production, transmission, refining, and consumption process.

An example is primary heavy oil and bitumen production, which has the lowest energy and capital intensity for extraction. Yet the produced stream has the lowest value to the conventional heavy oil producers, even though the final products, after upgrading, are the same as the products from mining and in-situ thermal operations (which receive greater royalty breaks, and require higher expenditures for infrastructure). Meanwhile, companies with upgraders will make higher returns by processing the easier to produce products, but the primary producers cannot afford to invest in R&D or equipment to further improve recovery from those deposits, due to the lower netback they receive for their production.

R&D Direction 3.11.1 – Impacts of Recovery on Downstream Upgrading – Investigation – In most industrial activities the optimization of a series of steps in a process, in isolation from knowledge or understanding of impacts on upstream and downstream steps, results in an inefficient overall system. R&D into full cycle investigations to optimize net societal benefits and energy efficiency, in the production to consumption of hydrocarbon streams, would potentially lead to significantly higher recoveries and net benefits from all oil sands streams.

13.6. Balanced Economic Comparisons of Options

An issue that has been evident in reviewing some papers on current oil sands developments is that there is a lack of consistent standards for calculations or estimations of potential recovery, energy efficiency and emissions. For example, not all producers are using the same definitions of "resource in place" for recovery calculations; Steam Oil Ratios (SORs), used to compare energy efficiency between projects are often not based on the same thermodynamic state; and adjustments of lab test recovery indications to reflect real-life field applications, vary widely. There are also wide variations in estimates of market demand potential, cost estimating factors, and forecasts of resource needs such as manpower, etc. This lack of consistency can lead to projects proceeding to commercialization, that are less efficient or more resource or emissions intensive than other options, assessed on a different basis or criteria.

R&D Direction 3.0.5 – Balanced Economic Comparisons – Investigation – With the increasing interest in oil sands by international investors who know little about the oil sands except their size, and the shortage of human and other resources, there is a growing need to improve methods of comparing projects and investments to avoid inappropriate and inefficient developments from proceeding.

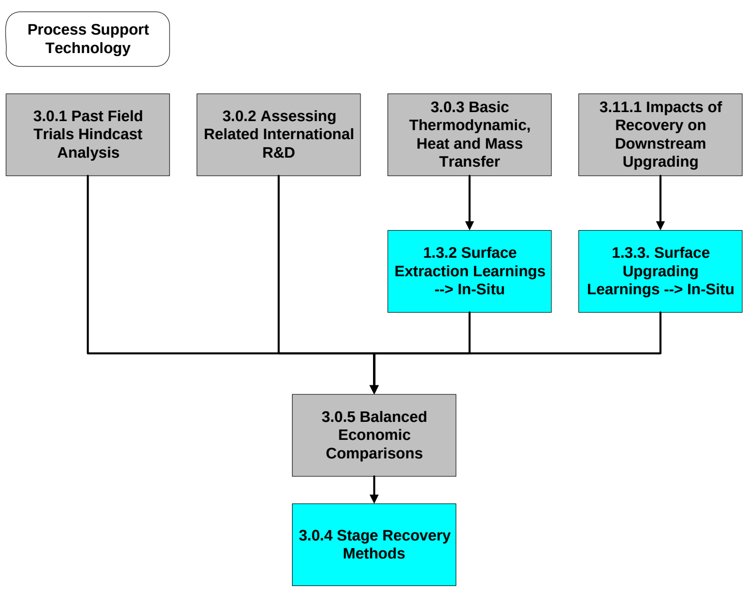


Figure 13.6 – Process Support R&D Directions

14. Sustainability Support Technology

Sustainability support technology includes base line environmental studies, groundwater studies, regional planning, safety, security of energy supplies and other socio-economic and environmental issues. E.g.: is it better to develop all the mineable area first, before looking elsewhere (putting all the stress on Ft. McMurray), or to spread the load by increasing and maintaining production from other heavy oil areas in parallel to meet a given production demand? It also looks at net full cycle GHG emissions, other environmental impacts, and potential alternate energy and/or injectant sources, assuming any type of oil sands development will always be very energy intensive.

14.1. Baseline Environmental Assessments

Previous roadmaps have already highlighted the need for greater efforts in the development of baseline assessments of natural, ecological and resource supplies for oil sands developments. Groundwater flows and characteristics, water supplies from the Athabasca River and interactions between the two will continue to be concerns that are likely to grow further as development proceeds. The main addition to the need for baseline work, as a result of development of "inaccessible" deposits, is that the area of study will have to be expanded to cover all oil sands areas, including an undefined buffer zone outside of the oil sands, which could also be affected.

14.2. Priorities for GHG Reduction Potential

Currently there is no real guideline for consistently attempting to assess the potential impact of a given technology, or area of research, on GHG emissions. Generally, this is left to R&D proponents to estimate, with varying degrees of credibility depending on the assumptions used and the economic weight given to GHG reduction. Prioritization criteria suggested might include three factors:

1. **Timing** – R&D activities, which could potentially result in a reduction in GHG emissions, especially methane, before 2025 are assumed to be preferred.
2. **GHG Impact** – Based on current carbon intensities the relative size of the reduction per m^3 or bbl of production should be the main criteria.
3. **Forecasting** – Managing GHG emissions, and the federal Kyoto commitment requires that forecasts of emissions be reliable, so that appropriate actions can be taken to respond. R&D that would allow better GHG forecasts is preferred.

R&D Direction 4.0.1 – Prioritization Based on GHG Criteria – Motivation - A standard method or set of criteria for assessing or estimating GHG related impacts should be developed for consistent use in assessing potential life cycle impacts of development and technology choices, to help provide direction for researchers, developers and R&D funders.

14.3. Priorities Based on Sustainability Criteria

Similar to GHG prioritization, similar efforts are needed in assessing the long-term value and impacts of new and existing technologies related to sustainability issues, so that the benefits or research can be articulated in a consistent fashion. Prioritization criteria might be:

- **Economic** – Relative net economic value to stakeholders directly impacted by the on-going operation of this sector. Higher and rapid returns on capital and long-term present value of a technology at times conflict in this assessment. Therefore, present value might be used as being the most relevant to the provinces, who are the primary owner of the resource.

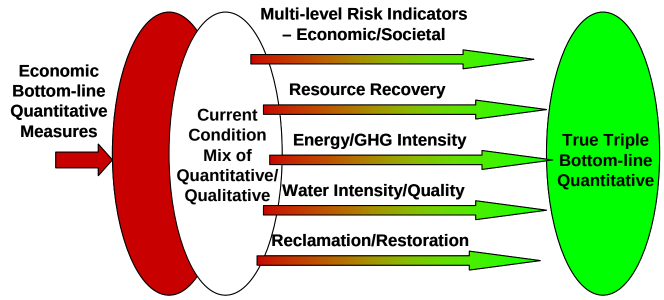


Figure 14.1 – Qualitative Assessment of Sustainability Factors

- **Environment** – Relative impacts of reducing non-GHG impacts on land, water, air and ecologies in the region. These tend to have a greater, and more controllable, impact than GHG emissions, and have the greatest impact on provincial regulations that govern the industry.
- **Security** – Relative positive impacts on health and well-being of local communities, for such things as employment, sources of funding for services, and long term effective use of resources.
- **Energy Intensity and Energy Source** – It may be desirable to include an energy intensity indicator in this analysis; however, it is likely that the other sustainability, and GHG factors, will already put a high weight on factors that lead to reduced energy intensity.

R&D Direction 4.0.2 – Prioritization Based on Sustainability Criteria – Motivation - A standard method, or set of criteria, for assessing cumulative impacts of environmental, economic and societal impacts should be developed for consistent use in assessing potential life cycle impacts of development and technology choices to help provide direction for policy makers, regulators, researchers, developers, R&D funders and the public.

14.4. Merging Priorities

Technology and development choices, and R&D directions, must balance a wide range of issues, including GHG emissions, sustainability issues, and assessments of the extent that any given positive R&D result might be applied across the entire bitumen and heavy oil resource base.

Criteria for prioritizing applicability might be based on an estimate of the total percentage of the oil sands areas where a potential research result might be applied to provide a benefit. The final merged priorities for R&D would combine the priorities of GHG reduction, Sustainability and Extent of Potential Application to provide an overall priority and ranking of R&D issues to be addressed.

R&D Direction 4.0.3 – Merging GHG and Sustainability Criteria – Motivation – To motivate research there must be a plan, priorities and ranking of R&D directions to attempt to focus the most effort on the directions of greatest impact. A process should be developed to allow this type of exercise to be implemented and reviewed on a regular basis as R&D progresses and moves into commercial application.

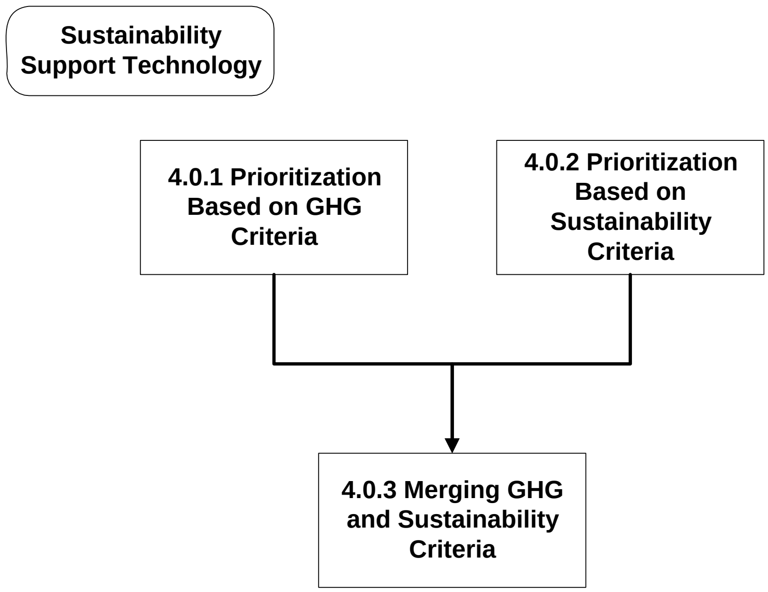


Figure 14.2 – Sustainability Support R&D Directions

15. Supporting the R&D to Expand the Resource

While, on the surface, it appears that there may be enough recoverable bitumen and heavy oil to last for 100 years, the reality is that much greater efforts and, potentially radically new approaches are needed to make production sustainable in the long term. The fact that many of the needs of the long-term could also enhance the present is a key factor in looking at starting the R&D effort into some new directions. Rising revenues, and rapidly expanding environmental/societal impacts, provide a compelling case for a similarly large increase in R&D funding, innovation and focus on the long-term, as well as the short-term, needs. Supporting of R&D, to expand the resource, must come in many forms to generate effective results, while still allowing for innovation and development of new ideas for commercialization. As PTAC's "Spudding Innovation" reminded us:

"We usually find oil and gas in new places with old ideas.

Sometimes, also, we find oil and gas in an old place with a new idea.

Several times in the past we have thought that we were running out of oil and gas.

Whereas we were only running out of ideas."

-Adapted from Parke Atherton Dickey (1958)

15.1. Supporting the R&D to Expand the Resource

The first step in supporting R&D is to have skilled people actually available, motivated and allowed the time to work on it. Many researchers and innovators provided feedback, from the March 2nd workshop, that more time is spent submitting multiple applications, reports and updates to multiple funding bodies, and competing with each other for limited funding, and grad students, than they can actually put into conducting research. While controls and decision-making processes are necessary for allocating funds and assessing results of R&D investments, the overall result should be active, motivated and energetic researchers, effectively collaborating with their peers, and communicating results widely with those who can progress the ideas to the next phase. The support system should work for all stages of the development process, from an initial concept, to a widely utilized and profitable commercial technology. Very few ideas will be able to progress to full deployment without the active, informed and effective participation of many stakeholders.

R&D Direction 4.0.4 – R&D Processes – Motivation – To motivate researchers and allow them more time to effectively conduct research, current R&D support processes should be reviewed and enhanced to improve overall R&D efficiency and effectiveness.

15.2. R&D Funding to Match the Size of the Resource

The Alberta Department of Energy, Oil Sands Developments, and AERI have funded a multi-year study, led by two of us (Godin and Heidrick), to assess past and current R&D funding on oil sands, by both public and industry stakeholders. While the report details have not yet been released, the results show that after a steep decline in public sector R&D spending from a peak in the days of AOSTRA[15] of $65-70 M/yr to $20-25 M/yr in the last decade, growing revenues are assisting industry to increase its level of oil sands R&D investment. Federal hydrocarbon research funding followed the same trend of decline after peaking, mainly through PERD Hydrocarbon funding, in the 1980's.

AOSTRA's efforts were reported to have contributed almost $1 billion (approximately 50-50 industry-AOSTRA) of R&D investment, in mainly oil sands research between 1976 and 1994. Key AOSTRA programs impacting today's oil sands developments are:

- **Development of SAG-D** – This has also led to VAPEX and other processes.
- **Concept of Mining Assisted In-situ Recovery** – which may be a direction that needs to be extended into the future.
- **New Bitumen Extraction** – now the mainstream technology for oil sands mining.
- **Initial Investigations of Carbonate Deposits** – This declined to near zero R&D investment levels.

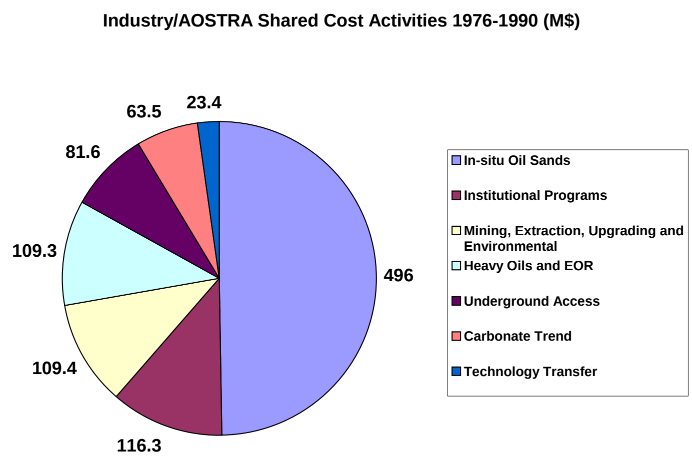


Figure 15.1 – Early Investment in Oil Sands R&D[16]

Despite these early investments and results, which are now paying off in billions of dollars of rapid oil sands developments, there are still many areas where improvements are needed in current technology, and new directions to follow for the future. Early R&D funding for the future expansion of the resource base must at least approach the levels reached by AOSTRA, especially while industry funding focuses on near-term investment in R&D, to address the growing impacts and needs to optimize their operations in "accessible" resources.

R&D Direction 4.0.5 – R&D Funding Levels – Motivation – Current R&D funding levels represent a very small percentage of total revenues from current operations,

[15] AOSTRA a 15 year Portfolio of Achievement.
[16] AOSTRA a 15 year Portfolio of Achievement

and an even smaller percentage of revenues soon to be realized, as new projects come on stream in the coming years. A process is required to continually assess and evaluate appropriate funding levels and directions targeted by funds from various levels of government and industry stakeholders.

15.3. Sourcing and Allocating Long-Term R&D Funds

While AOSTRA seems to have met the needs of the 1980's, future funding of long-term oil sands and carbonate R&D will take place in a totally different environment. Most producers now have lower levels of in-house R&D resources; organizations such as ARC have been re-tooled to support commercial development; and there is now a high priority need to support industry responses to any near-term problems and optimization of existing operations and developments, which may take precedence over efforts for the long-term.

Recent increases in industry R&D efforts are mainly focused on near-term development issues, and adaptation/demonstration of technologies. Industry R&D funding priorities will likely remain to be focused on areas with a rapid return on investment, leaving most long-term R&D investments for funding by non-producer researchers and governments. With ARC now in a semi-competitive position with private researchers and technology developers, greater reliance will have to be placed on utilizing other institutional research organizations, associations such as PTAC, or alternate processes for unbiased assessment, prioritization and allocation of funding.

R&D Direction 4.0.6 – R&D Fund Sourcing and Allocation – Motivation – Some type of integrated sourcing and allocation process is needed to help all stakeholders contribute appropriately to the R&D efforts, with funds allocated based on individual stakeholder objectives, but allocated through a collaborative, fair and transparent process to the highest priority and most promising work.

15.4. Road Mapping the Future

One type of effort, which appears to be very useful in focusing and visioning R&D needs, is the use of "roadmaps". Roadmaps can support researchers by defining and prioritizing key R&D outcomes, postulating potential solutions and showing how various research efforts fit within the overall long-term development framework to address anticipated or outstanding problems. To maximize value, these roadmaps must be detailed enough to inform the researchers, accurate enough to describe what criteria successful solutions might have to meet, and must highlight key areas of technology which need to be addressed. Roadmaps should recognize that technology development is rarely successful if all the effort is focused on one predetermined route, and that roadmaps need to be frequently updated as the oil sands landscape and road conditions change.

R&D Direction 4.0.7– Roadmapping Support – Motivation - A process should be developed to build, communicate and periodically review integrated levels of roadmaps, at various levels of detail, covering high-level directions for the entire industry, by oil sands deposit type, and potentially by support technology or R&D focus area.

16. Next Step – Detailed Roadmap

As covered in Section 3, the intent of this high-level roadmap was to locate the cities and provinces on the map, to lay the foundation for later work to fill in more specifics on the potential roads, highways and stops along the way. To allow for Phase II development of a more detailed roadmap(s), as suggested in section 15.4, some "exploratory" research is needed to help clarify the new directions and long-term support needs identified in this study.

16.1. Exploratory Efforts and Data Collection

Initial exploratory efforts focus mainly on reassessing information from previous studies undertaken in the 1970's and 1980's. Much of this is contained in AOSTRA and UNITAR conference proceedings on heavy crude and tarsands. While the UNITAR proceedings are publicly available in libraries, access to many AOSTRA reports is restricted, which will inhibit building on past knowledge. The exploratory efforts should focus on mining these data and information sources, in light of potential applications to the currently "inaccessible" deposits.

16.2. Assessing Potential

As an early step in the exploratory process, a technical steering committee, potentially an extension of the PTAC committee formed for this project, should be formed, funded and structured to develop processes and methods of assessing the relative potential of various R&D directions for inaccessible resources. This has already been undertaken at a very high level for general directions. However, more time, effort, and basic background investigation work are necessary to properly assess the 80+ technology directions outlined in this report. A consensus on methods to assess R&D direction potential, against a range of stakeholder criteria, would be invaluable in helping to fund further explorations to define steps in a more detailed roadmap.

PTAC has proposed one follow-up exploration study, to develop lowest possible GHG emission scenarios for potential development for carbonate and partially depleted primary bitumen and oil sands deposits. If funded by NRCan, AERI and others, this could serve as a model for developing other potential assessment studies for other research directions for other deposits, or targeting other preferred outcomes. I.e. lowest GHG emissions may not result in the most economic options. The final ideal scenario will be one which best balances all stakeholder objectives.

16.3. Looking for Resource Development Synergies

To achieve a fully integrated R&D development plan for expanding the oil sands resource, consideration must also be given to a wide range of synergies with other energy and hydrocarbon developments and roadmaps, such as:

- Clean Coal, Coal/Petrochemical Integration Research
- Alternative Energy Production, Transmission, Storage and Utilization Options
- Enhanced Recovery of other Hydrocarbons – EOR, EGR, ECBM, Biomass, etc.

➢ Use of Locally Available Byproducts – Sulphur, Coke, Flyash, CO_2, etc.

16.4. Starting the Next Roadmap

Once the key R&D Directions proposed in this study and illustrated in Figure 16.1 have all been addressed by exploratory studies mandated and funded through the proposed steering committee, then a new project should be launched to expand the current high-level roadmap into a more detailed roadmap, which will provide more detailed direction to initiation of new R&D building appropriately on past efforts.

It is suggested that this detailed roadmap be managed by an on-going steering committee with a gradual turnover in membership to ensure continuity, while also facilitating the addition of new ideas and viewpoints to the mix. Consistency will likely be less important than committee member commitment, vision and ensuring that the on-going process remains dynamic, to ensure action and progress.

Heavy Oil and Bitumen Resource Expansion - Key Focus Areas by Resource

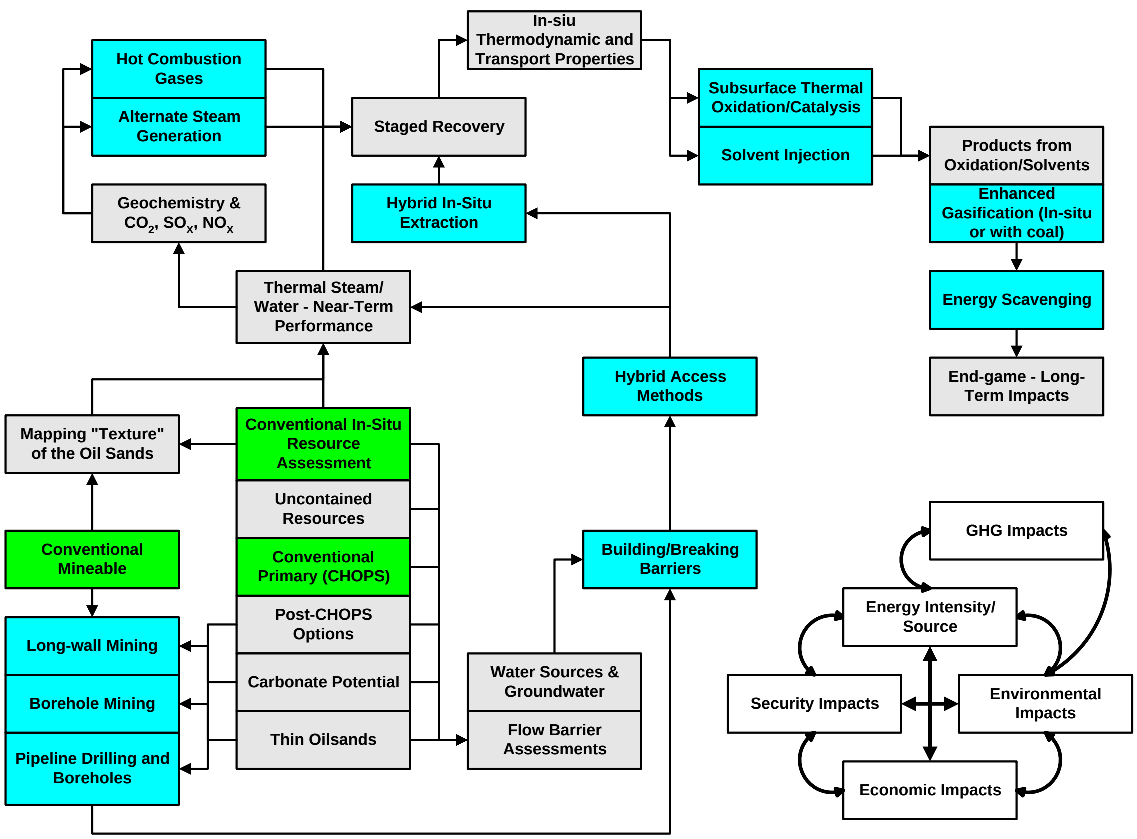


Figure 16.1 – Key R&D Directions

16.5. Participation in Road Mapping

While initial funding for long-term R&D will likely come primarily from governments, with in-kind support from producers, other stakeholders such as industry consultants, researchers, innovators, NGOs and regulators should continue with a high degree of involvement in any road mapping process. As per PTAC's normal model, funders should have the final say in what projects proceed. However, broader input and discussion is needed to ensure that the process is transparent, and that R&D efforts undertaken, based on the roadmap, address the main related sustainability issues of concern to other stakeholders, with the appropriate type of R&D activity. This should also help to ensure that the R&D output, will feed smoothly into some process to transfer knowledge and technology to the appropriate vendor, service/supply or other sector, for follow-up commercial development, demonstration and transfer to application. Participation of all potential stakeholders in the process will help to avoid duplication of efforts, or loss of momentum, as the technology moves towards application.

16.6. Balancing Producer, Public and Environmental Goals

Ultimately R&D projects, and resulting solutions, must meet the, sometimes conflicting, goals of the producers, the public (as represented through government agencies and NGOs) and environmental needs. Achieving the appropriate balance requires the participation in good faith of the key stakeholders, and should be based on a reasonable consensus, based on shared knowledge and candid, mutual understanding of stakeholder drivers and objectives. Achieving consensus can take more time in the early stages. However, true knowledge-based and unbiased consensus should help to achieve significantly improved results in the long-term, especially where there is sufficient lead time to direct efforts, in advance of a crisis or critical need developing.

17. Conclusions and Recommendations

In total, this report has highlighted over 80 potential R&D directions for addressing anticipated needs, which may allow expansion of the heavy oil and bitumen resources, while at the same time attempting to mitigate GHG and sustainability issues. While some of the directions are unique to the deposits being addressed, other directions are extensions of current concerns with development of the "accessible" resources. Given the long lead times necessary to develop new technology approaches, respond to new insights from fundamental research, and learn how to optimally apply the gained knowledge to oil sands resources, it is appropriate that work in these new directions begin now to prepare for the future. Many of the new, sustainability and support R&D directions identified could prove valuable to current operations, even though they are not absolutely necessary to allow economic development of the current oil sands "sweet spots". However, the sweet spots comprise only a small part of the oil sands resource, and new methods are needed to enhance the sustainability of oil sands operations, in the medium and long-term, independent of oil price, and with minimum negative impacts.

While the project steering committee felt that it was too early, and there is a lack of information at this time to prioritize all the potential R&D directions, they did provide some input to help assess the broader R&D Directions.

17.1. GHG Technology Focused R&D

The primary goal of this study was to highlight R&D to reduce GHG emissions from future operations in "unconventional", "inaccessible", or "expanded" oil sands deposits. Without being able to address specific technologies and options, it is very difficult to assess how successful any future technology will be in reducing GHG intensities. However, directionally we have identified areas where GHG reduction R&D can preferentially be focused.

- **GHG Highest Priority** - Not surprisingly the highest ranked priority, based on a focus of moving in the direction of lower GHG intensities, and reduced total GHG emissions, was in **Alternate Recovery Processes**. Currently, almost all commercial heavy oil and bitumen production methods are extremely GHG intensive. The sole exception is primary production, as long as vent gases are conserved, which is more dependent on regulation than on technology. However, primary production only recovers a small fraction of the resource. Other methods that are being used, tested or proposed all have much higher GHG intensities than conventional oil operations, in Canada and elsewhere, and all will likely increase in GHG intensity as lower quality resources are accessed over time.
- **GHG Second Highest Priority** – Even with the development of lower GHG intensity recovery methods, energy needs of oil sands development will still be massive, with a high percentage of the energy value of the production being consumed. Therefore, the secondary priority for GHG emissions reduction is to find and **Assess Alternate Energy Sources**, such as geothermal, coal, nuclear, or other sources to reduce the consumption of high value natural gas, and to provide synergies with other energy uses.

17.2. Sustainability Technology Focused R&D

From a sustainability point of view, the vast oil sands developments, also have vast consequences across most areas of economics, environmental and societal/security; locally, regionally, nationally, internationally and globally. While GHGs are normally considered a global issue, other issues are much more acute at the local scale and include issues related to cost of development, housing availability and prices, water use and quality, infrastructure needs, and human resource availability.

- **Sustainability Highest Priority** – The highest priority direction for sustainability is a large body of effort needed to address the complexity of assessing hundreds, if not thousands, of sustainability issues, which arise where a resource undergoes exponential development in an isolated, natural region. The efforts required to determine baseline data, to determine what will be impacted and how, to assess potential options for mitigation, to gain consensus on solutions and to implement them, are as vast as the resource being developed. New tools are needed that can address and track these **Cumulative Impact** issues effectively and that can be applied in the near-term and expanded as the resource expands into new deposits with new impacts.
- **Sustainability Second Highest Priority –** The second highest priority for sustainability is the highest priority for GHGs: **Alternative Recovery Processes**, which demonstrates the high degree of synergy between sustainability and GHG/energy efficiency improvements in oil sands. The recovery process chosen, for a given deposit, is the primary factor driving all benefits and issues over the long-term. Focusing on continuing to conceive and develop new innovative recovery options or methods is still needed despite the many years of effort already expended in this area.

17.3. Supporting R&D Efforts

Supporting R&D efforts for the long-term development of both current and future deposits requires a significant and long-term commitment to **Changes** in funding and facilitating effective R&D. Not only will there be many processes, options, and geologic, chemical and physical processes to investigate, these will have to be investigated over a broad range of unique deposits and situations. Therefore, there is unlikely to be a single “silver-bullet” solution. The wide variability in the oil sands and carbonate deposits will drive increasing demands for new solutions and options. In an environment of competing demands for knowledge workers, and with the on-going loss of experienced oil sands researchers, the R&D support system requires a significant revamp to enable a young generation of researchers to absorb past knowledge, and to thrive in a collaborative, productive and rewarding career of discovery. These efforts will require:

- A **Vision** of where the research is leading;
- Defined **First Steps** on where to start R&D efforts;

- Recognition of the growing **Dissatisfaction** in the R&D community with the status quo of tight, widely variable funding, non-value-added bureaucracy and disruptive researcher competition;
- The **Support System** must provide access to data, defined success criteria, a fair, transparent and efficient funding decision process, and shared rewards for shared successes;
- At the same time, **Resistance** and barriers to conducting R&D must be reduced by demonstrating to stakeholders how the collaborative results can help them to all meet their individual objectives.

17.4. Detailed Roadmap Development

All of the requirements listed in 17.3 can be addressed through greater and more effective use of roadmaps, at various levels of the oil sands R&D process. The sooner these roadmaps can be developed, fleshed out, and turned into R&D action, the earlier any benefits, breakthroughs or improvements can be realized. Developing roadmaps takes time and effort. However, as in any project, without some type of plan, and value added planning effort, it is extremely unlikely that the overall objectives of the task will be achieved to the satisfaction of all stakeholders.