OIL SANDS TECHNOLOGY ROADMAP
UNLOCKING THE POTENTIAL
JANUARY 30, 2004
The Chamber is well known for its success in pursuing oil sands initiatives on behalf of our members and stakeholders. The report of our National Task Force on Oil Sands Strategy became the pre-eminent vision for the development and expansion of the oil sands. That plan became a reality through the efforts of our members, governments and partners. The Alberta Chamber of Resources is now pleased to release the Oil Sands Technology Roadmap, a strategy that will be essential to the continued development of this vast resource.

Over almost 40 years of commercial activity, oil sands industry pioneers have developed the necessary technology to extract oil sands bitumen and produce synthetic crude oil to compete at world prices. The industry now has many industry leaders, who are well on their way to producing 2 million barrels daily in aggregate by 2012. By then, the oil sands industry will be the dominant Canadian source of liquid hydrocarbons and will ensure future domestic oil self-sufficiency while expanding our export potential.

The Oil Sands Technology Roadmap identifies an ambitious vision of 5 million barrels daily by 2030. It describes many of the internal and external challenges that industry must address to achieve this goal in an economical, environmental and socially responsible manner. Technology advances have powered the industry we know today, and will be equally important in the future. This report identifies the new technology required that will underpin the future prosperity of the industry and its many stakeholders.

Investments in technology development for this industry must be dedicated and sustained. Governments and Industry need to develop a collaborative long-term strategy. Many gains have been made in organized research and development, but we will need to take fresh approaches and refocus on this task. The Oil Sands Technology Roadmap will provide that direction and will act as a guide, to assist and monitor developments over time, and to support those who are developing new technologies in Alberta, in Canada and around the globe.

We extend our thanks to the hundreds of people who have contributed to the Oil Sands Technology Roadmap, a collaborative effort between the Alberta Chamber of Resources, Natural Resources Canada, the Alberta Energy Research Institute and our oil sands stakeholders. We encourage all stakeholders to contribute again, as we translate technology needs into concrete research and development plans. We urge you to review this document, to consider the future and, most importantly, to act!
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FOREWORD

This report concentrates on the identification of the challenges and technology gaps as part of the development to date of the Oil Sands Technology Roadmap. It is based on the original ‘discussion’ document developed in August 2003 and also incorporates feedback derived from three workshops held during September 2003, in Fort McMurray, Edmonton and Calgary. While this report is technical in nature and content, we have attempted to make it both easy to read and readily understood by all stakeholders.

The following individuals from industry, government, and the research community donated their time and made significant contributions as chapter editors both of the pre-workshop discussion document and of this report. Their work reflects not only their individual contributions but also that of colleagues and associates.

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Len Flint was the overall coordinator of the Technology Roadmap work. Carol Fairbrother coordinated Steering Committee meetings and the organization of the workshops, and contributed background research and editing throughout the project. As a final content editor, Len Flint accepts responsibility for any errors or omissions in the inclusion of comments from industry-wide contributors. Any serious omissions of technology development opportunities in the Roadmap will be incorporated in the next phase of this work.

During 2004, work will begin on concise technology development plans in all key areas, and these will be published as they become available. The plans will include expectations on the division between industry and publicly funded research, will identify key R&D providers, the timeframe and required funding.

### REPORTING STANDARDS AND CASE ASSUMPTIONS

Throughout this report, the following reporting standards have been used, largely dictated by conventional practice in the recovery, upgrading and oil refining industries and emissions reporting in Canada.

- Oil volumes are in **barrels**, and assume a conversion factor of 6.29 barrels per cubic metre.
- Water volumes are in **cubic meters**.
- Gas volumes (natural gas and hydrogen) are in **standard cubic feet**, and assume a conversion factor of 33.4 standard cubic feet per normal cubic metre.
- Emissions (normally CO$_2$ equivalent) and solid by-products are in **metric tonnes**.
- Oil gravities are reported in **°API**. On this scale, water is 10°, bitumens are typically in the 8°-11° range, and light crudes are in the 35°-40° range.
- All financial numbers are in **Canadian dollars** unless otherwise stated.

Where applicable, financial projections have been generated assuming:

- Light crude (WTI) = $25 US = $33.33 CAN
- Natural Gas = $5 per Giga-joule (HHV)
- Electric power = $60 per MW-h
- U.S. / Canadian exchange rate = 0.75 cents

**Capital Costs** are dealt with by industry participants in different ways, and expenditures vary significantly between expansions of existing plants and ‘green field’ sites. Where capital cost estimates are included in this Technology Roadmap for illustration, they are an estimated per barrel cost, based on a 12% ROI on an 8% discounted cash flow over a 25 year project life with typical tax rates and capital cost allowance deductions.

There are a number of internally generated estimates in the report for such as aggregate industry natural gas use, cumulative Greenhouse gas emissions and sulphur production. The basic numbers per production unit (barrel of bitumen or derivative product) are included in various figures and text. **Aggregate estimates** made for three periods - 2003, 2012 and 2030 - assume the following representative mix of bitumen based operations:

2003: 750 thousand daily barrels of synthetic crude, from largely mined bitumen, and 350 thousand daily barrels of thermally produced bitumen in diluted products.

2012: 1.5 million daily barrels daily of synthetic crude and other upgraded products from a 65/35 mix of mined and thermally produced bitumen and 500 thousand daily barrels of thermally produced bitumen in diluted products.

2030: 4 million daily barrels daily of synthetic crude and other upgraded products from a 50/50 mix of mined and thermally produced bitumen and 1 million daily barrels of thermally produced bitumen in diluted products.
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Indeed, after nearly 40 years of commercial production encompassing two distinct phases of growth, the industry is now poised for a third wave of development, one that could see production increasing more than twofold to five million barrels a day, or 16% of North American demand by 2030.

This increased production could generate an additional $40 billion of economic growth in Canada, create tens of thousands of new jobs across the country, and produce up to $90 billion in new investment over the next 30 years.

To arrive at that point, however, we must plan for it. What we do today, sets the stage for tomorrow, raising the question: what is the best way forward? This roadmap helps set a course for oil sands industry growth by identifying issues and technology options to overcome challenges that stand in the way. As producers work toward this new vision, they will rely heavily on technology to grow a truly sustainable industry.

To generate and maintain momentum in the oil sands industry, change will need to occur on a number of fronts: product diversity must be expanded, markets in North America and the Pacific Rim must be developed, sustainable development must be apparent in all aspects of operations, and economic wealth must be shared broadly across the country and more narrowly among those communities - aboriginal in particular - likely to be most affected by continued development.

As production of conventional crudes and natural gas decline, and with the right mindset and technology, the oil sands is well positioned to provide a sustainable bridge between non-renewable fossil fuels and cleaner energy options for the future.

Toward that end, it is intended that this Roadmap will drive a review of research and development already underway and facilitate the development of new technology in the years ahead.

For each of the oil sands recovery and process steps, technology based sections of this report highlight opportunities for continuous improvement in the technologies employed today, and step-out advances that require longer lead times to develop to commercial application.

**Mining Based Bitumen Extraction:** The recovery rate of bitumen from mined sand today is about 90% with good quality ore, with extraction processes accounting for the largest share of the loss. While there is room for new technology at the mine face, most continuous improvement opportunities might be available in areas such as material handling and better designed equipment. More significant step-out technological opportunities could also come into play: improving tailings disposal processes, for example, or introducing “at face” continuous mining processes.

Recovery can be improved at primary separation - where 6-8% of bitumen now lost might be partially recovered with increased mechanical
availability, reduced sensitivity to process
temperature, extended component life, or other
technologies. Froth treatment also offers possible
solutions in both the naphtha and paraffinic
solvent based processes. A viable target to aim
for in primary separation is a 50% reduction in
non-labour costs. No major breakthroughs or
alternatives to water based bitumen extraction are
expected leading up to 2030. Rather, the greatest
advances will come in reducing the negative
environmental and other impacts of the process.

**In-Situ Bitumen Production:** Ultimate recovery
rates are anticipated to be in the 40% to 70%
range. Unlike mined bitumen, In-Situ production
can be handled conventionally in downstream
refineries. The steam assisted gravity drainage
(SAGD) process can still benefit from further
technology development. A paramount challenge
will be to develop new markets for some of the
increased production. As well, if SAGD production
is to expand greatly, much of the new production
will need to be upgraded to higher value product.
Continuous improvement opportunities for SAGD
include reducing steam-to-oil ratios, introducing
new solvent processes, developing more reliable
down-hole pumps, and enhancing water recycling
and reuse. Examples of step-out technologies
include In-Situ combustion or gasification to
warm up the reserve and mobilize the bitumen,
and introducing catalysts in production strings to
help reduce energy consumption.

**Sustainable Development on the Ground:** For
every cubic metre of synthetic crude produced at
the major integrated plants, there are six cubic
meters of sand and 1.5 cubic meters of mature
fine tailings that need to be transported and
reclaimed. The industry must invest in developing
and applying the right technologies to reinforce a
strong environmental record. There are a number
of challenges associated with doing this.
Reducing water use and the cost of solids
handling, developing more innovative ways to
reclaim mining land, and improving management
of the Boreal forest, are among them.

The overall size of the industry's environmental
footprint probably cannot be reduced, but the
active area of disturbance can be minimized by
innovative approaches to tailings management.
Two possible ways forward are: managed
disturbance with a commitment to future
reclamation; and accelerated tailings dewatering
and reclamation technology, likely adopted on a
regional basis. A variety of technologies may also
be available for improved tailings water
management including new tailings pipe
materials and better pumps, accelerated fine
tailings settling, and fine tailings consolidation.
Though improvements are also possible in the
In-Situ segment, the footprint is not as large and
the technological undertakings not as onerous.

**Upgrading in a Dynamic Market:** About 65% of
oil sands production is upgraded, largely to a
light, sweet synthetic crude oil. Upgrading faces
a number of challenges in the years ahead.
Keeping costs down is a constant one. Improving
the quality of synthetic crude oil from a refinery
perspective is another. Reducing an increasingly
unsustainable level of natural gas consumption
for hydrogen production is yet another.

A combination of coking and ebullated bed
hydroprocessing methods are used for primary
upgrading in the industry, with capacity currently
skewed in favour of the former. Quality issues
exist between current upgrading and refining that
strongly suggest the need for synthetic crude
quality improvements as markets expand. Much
of the research on upgrading technology has
taken place in the United States, but the
Canadian oil sands industry is well positioned
to influence research directions and outcomes.
A variety of technology improvement
opportunities exist in both coking and ebullated
bed processes. The industry will also widen its
contribution to high quality fuels production,
and extend into petrochemicals.
There are a variety of existing or step-out technologies that may hold promise for the improved effectiveness of future upgrading. They include certain recovery processes that have the potential to improve “as-produced” bitumen quality, moderate upgrading processes involving field upgraders, primary processes to remove and consume residue, and advanced hydroprocessing catalysts that significantly improve conversion.

**Energy and Hydrogen:** The historical dependence on abundant and inexpensive natural gas for fuel and the generation of hydrogen cannot be sustained. Alternative energy technologies currently available include: coal combustion; gasification, which is not currently as cost effective as coal combustion; nuclear energy, a clean source though suffering social barriers; and internally generated fuels such as the residue of produced bitumen. Alternative hydrogen technologies include: steam methane reforming, the method of choice during an era of low natural gas prices; and the gasification of coal or oil sands residue, which holds the greatest promise as an alternative hydrogen source. There are also a variety of future technology options, though barriers to development exist in each case.

Air Emissions: Challenges in managing emissions will become greater with time, and will only be met successfully through attention to community relations. Between 70% and 85% of life cycle greenhouse gas emissions come from the burning of the final fuel products. Still, the oil sands industry needs to do much better than “business as usual.” The 15% or so of life cycle emissions released at the production stage are to a large degree the result of high energy use for bitumen recovery, and energy reductions are a major target for overall cost reduction. However, the likely drive to internal sources of energy to replace natural gas will trend to even greater emissions.

Opportunities for abatement of sulphur dioxide largely come down to stack gas scrubbing. Nitrogen oxides (NOx) come partly from furnaces, where the industry is already moving to low-NOx burners. Of increasing concern are NOx emissions from diesel trucks in the mining sector. Fuel switching is an alternative and more research is needed.

To reduce carbon dioxide (CO2) emissions, sequestration - storing CO2 in depleted oil and gas reservoirs, in aquifers or in enhanced oil recovery or coal bed methane projects - is high on the list of future solutions. However, sequestering is only feasible today for more concentrated and easily consolidated sources of CO2. It could also be a costly process. The issue is an energy industry-wide one, and it is expected that solutions will be equally applicable to the oil sands. The need for carbon dioxide pipelining for large scale sequestering is another area for industry wide cooperation.
EXECUTIVE SUMMARY

The Way Forward on Technology: Technology has been a large factor in achieving improved economics for the oil sands industry over its first 40 years of commercial operation, and cooperative technology development will continue to be a key to enhancing the industry’s ability to reduce costs and meet increasing environmental challenges. Over the last decade, there has been a significant amount of R&D coordination and work taking place in organizations like the Canadian Oil Sands Network for Research and Development, the Petroleum Technology Alliance Canada, the CANMET Energy Technology Centre in Devon, the Alberta Energy Research Institute, the Alberta Research Council, and the universities of Alberta and Calgary. Therefore the need for a renewed approach to a technology development plan does not start from zero. There is an excellent research base to build on if industry takes a lead role in encouraging and funding further research and development. Collaboration will facilitate long-term funding and help produce more all-encompassing, more effective outcomes.

Long-Term Development for Society: The industry will face a variety of familiar challenges en route to 2030—reducing the costs of production, for example. Relatively uncharted territory, however, lies in the amelioration of public concerns regarding expectations of corporate social and environmental responsibility. Society as a whole, which either grants or withholds permission for industry to practice, is a major stakeholder in economic development. Accordingly, the oil sands vision focuses on the long-term and re-frames development in Northern Alberta as a model that is envied and copied by other regions. Elements of that model include new patterns of institutional cooperation, a cooperative approach to managing the workforce and other requirements. We foresee the emergence of Wood Buffalo as a model for the adoption of economic, social and environmental accountability as standard practice among oil sands developers.
VISION – CANADA’S OIL SANDS INDUSTRY WILL BE A WORLD LEADER IN PRODUCTION, AND IN THE VALUE THAT IT CREATES IN ITS PRODUCTS. THE INDUSTRY WILL EMPLOY ECONOMICALLY EFFICIENT PROCESSES AND TECHNOLOGIES IN A WAY THAT MINIMIZES THE ENVIRONMENTAL, HEALTH AND SAFETY IMPACTS OF PRODUCTION, AND SHARES THE OPPORTUNITY FOR WEALTH GENERATION ACROSS THE COUNTRY.
Crude oil remains a dominant primary energy source, due to its comparatively low cost, ease of use and flexibility to power both economic growth and enhanced standards of living. Such demand will remain relatively constant at more than 35% of the primary energy basket, at least until 2030, according to the International Energy Agency (IEA). Both the IEA and the US Energy Information Administration (EIA) predict that world demand for crude oil will climb from 80 million barrels in 2003, to more than 120 million barrels daily by 2030, 25% of which (approximately 30 million barrels daily) will continue to be consumed in the United States and Canada. Both sources cite an approximate 1.5% increase per year in demand for crude oil and petroleum products over the same time period. 75% of this increase in demand is attributed to the transportation sector.

Concurrent with increased demand, there are predictions of marked declines in North American production of conventional crudes and natural gas.

Canadian oil sands, a non-conventional source encompassing the Athabasca, Peace River, Cold lake and Wabasca deposits, is increasingly recognized as a strategic resource and a potential contributor to North American energy security. While predictions to 2030 might be contentious, projections beyond are even more so. Nonetheless, demand for crude oil and fossil fuels will remain significant well beyond 2030. New or alternative energy sources will eventually begin to capture market share, but hydrocarbons will still be required as a foundation upon which other forms of energy will build.

The National Task Force on Oils Sands Strategies, through the leadership of the Alberta Chamber of Resources (ACR), published in 1995 the landmark set of reports entitled “The Oil Sands - a New Energy Vision for Canada”. Despite what was then considered a bullish vision of the industry's potential, the prediction of up to 1.2 million barrels daily by 2020, has already been achieved by an increasingly dynamic industry.

Underpinning this Oil Sands Technology Roadmap is the vision to reach five million barrels daily oil sands bitumen production by 2030. While this volume of production may appear ambitious, it is possible simply considering the size of the reserve of 175 billion barrels of recoverable oil by known technology. This is comparable to other similarly sized world crude reserves in countries such as Venezuela and Saudi Arabia. Technology may unlock an even larger portion of the volume in place. Five million barrels daily would represent around 16% of North American demand by 2030.

Technology development and adoption has rapidly reduced supply costs and increased the economic viability of oil sands development with world crude prices at sustained levels at or above $20 (U.S.) per barrel. This cost reduction, combined with favourable royalty regimes, has allowed the industry to proceed well into a second wave of development, planned to reach two million barrels daily of combined unprocessed bitumen and synthetic crude oil by 2010-2012.

**Product Diversity**

Oil sands will increasingly be seen as a versatile energy source, expanding from the two-product industry today. Achieving the level of development envisaged during the decline in conventional oil and gas reserves will also see an expanded role, with multiple marketable products. The distribution of end uses depicted in Figure 1.1 should be seen only in schematic terms; the market place and internal industry needs will determine the actual market mix.
To conserve natural gas - currently a major building block in oil sands development - the industry will need to find ways to become internally sufficient in energy and hydrogen, or use other abundant external sources. The oil sands industry does not want to contribute to a ‘bidding war’ for this clean energy source, nor threaten supply to the petrochemical industry. Oil sands by-products will maintain feedstock supply security, and offer future growth opportunities in petrochemicals.

Extending bitumen upgrading to higher quality synthetic crude also results in substantial production of finished ‘green’ distillate fuels, some of which can be marketed separately for higher added value.

New Markets
The expansion of production will need to be matched by new markets, still largely in Canada and the U.S. (for example, more deeply into PADD (Petroleum Administration for Defence

District) II and PADD III as well as increasing exports to California and Washington State (PADD V). Expanded pipeline infrastructure will also allow access to Pacific Rim markets.

Sustainable Development
Increased oil sands production cannot be considered separately from the environmental and social impacts. Sustainable development will require energy self-sufficiency, decreased greenhouse gas emissions and water usage, as well as a concerted effort by all stakeholders to define and plan the social infrastructure. The oil sands industry must maintain its current ‘permission to practice’ from Canadian society, by continuing to improve its environmental and social performance in all areas, while securing economic gains for the country. The oil sands industry will be world leaders in the adoption of new technology, and cooperative approaches to ensuring long-term sustainable development.
**Economic Benefits**

The scope of the oil sands opportunity is enormous for the whole country. Highlighted here is the potential impact on the National GDP (Figure 1.3), currently standing at around $1 trillion annually.

The job creation potential, and the ways in which the whole country shares in the wealth today and in the future are major drivers. The plans to 2012, already well underway, will lift the oil sands contribution to around 2% of current GDP by that time, and the further development to 5 million barrels daily could add a further 3-4% of current GDP.

However, the relatively high cost of oil sands extraction and the potential to produce value added products is a double-edged sword. On the one hand, costs need to be kept under control and continually reduced to ensure sustainable economic viability, especially in the face of fluctuating crude prices. On the other hand, the need to develop and implement a high level of technology and process innovation requires expenditure in new research and development.

Oil sands projects create a range of employment opportunities across a broad cross section, from skilled labour to high-tech scientific and engineering disciplines. The Petroleum Human Resources Council has determined that an estimated 8,000 new direct positions will be created during the next 10 years with a doubling of oil sands production. Furthermore, it is expected that three indirect jobs will be created with each direct position. Therefore, by 2012, the present development pace will create approximately 32,000 new direct and indirect jobs.

Generally, oil sands projects require a large investment of capital. This investment will be increased by $30 billion for every million barrels of daily production, if the bitumen is upgraded in Canada.

Theses investments are not only beneficial to Alberta, but are shared across the country as demonstrated by Figure 1.4. Employment benefits follow a similar pattern.
**Cultures Meet at the Resource**

The location of the oil sands, as well as the large employment needs, especially in the mining and upgrading sectors, have created opportunities for aboriginal communities to share in the investment benefits. This sharing of opportunities has been done at the outset of new projects through consultation, education and training, as well as supporting aboriginal service industries. This will be a continuing trend, bringing all cultures under the oil sands development tent.

**A Canadian Project**

In conclusion, the development of the oil sands is a project of enormous potential benefit, not just in Alberta but also across the country. Furthermore, exports of products that are upgraded to the maximum possible extent in Canada, provides an unparalleled opportunity for wealth and job creation, and infrastructure development. With the right technology, the oil sands will provide a sustainable bridge between non-renewable fossil fuels and other competing energy options for the future.

**FIGURE 1.4 CANADA-WIDE INVESTMENT SHARING**

- Alberta: 40%
- Atlantic: 19%
- Other west: 6%
- Quebec: 8%
- Ontario: 27%

Sources: NEB/OSTRM (1995)
2. KEY CHALLENGES FACING THE INDUSTRY

THE OIL SANDS INDUSTRY HAS MANY CHALLENGES AHEAD TO MEET THE VISION OF CONTINUED EXPANSION BEYOND THE CURRENT WAVE OF DEVELOPMENT TO 2012. WHILE COST REDUCTION WILL CONTINUE TO BE A MAJOR FOCUS, MORE ROBUST OIL PRICES AND SOUNDER ECONOMICS ALSO REQUIRE THE INDUSTRY TO ADDRESS OTHER CONCERNS AFFECTING THE BROAD BASE OF INDUSTRY STAKEHOLDERS.
The history of oil sands development has been marked by solving challenges with technology that enabled what can be described as waves of development. The first and second (current) waves, primarily addressed internal concerns, especially the high costs. This section discusses much broader challenges to the industry in a potential third wave of development to 5 million barrels per day. Societal issues will be discussed in the last section. Figure 2.1 is an illustration of the internal major challenges, in no order of priority.

**FIGURE 2.1 CHALLENGES TO ACHIEVE THE VISION**

While many of these challenges will be covered in some detail in this roadmap, a number of others, such as construction costs, trade skill base and pipeline technology, are more appropriately dealt with by other initiatives, and we offer only general comments in this section.

**The Cost Structure**

While the resource has been recognized for centuries, there was no substantial activity to develop it until the mid-1960s, with the startup of the Great Canadian Oil Sands plant (now Suncor). Investments in oil sands projects have become more attractive due to the increasing price of crude oil and because technology improvements have enabled operators to bring down the costs of production.

Figure 2.2 illustrates how the industry has reduced costs, both for integrated mining and upgrading projects, and also for in-situ production. In the former case, the improvements have been largely at the mine, with bitumen recovery. Step changes such as the move from draglines and bucket wheels to truck-and-shovel have contributed the most to bringing down costs. Similarly, in-situ costs have benefited from new technology by reducing steam to oil ratios. Even newer technology, currently being tested, will continue this positive trend. More research is needed so that costs will continue to be reduced to withstand cyclical changes such as future downturns in crude prices.

**FIGURE 2.2 SUPPLY COST HISTORY**

Source: NRCan
**Expanded Markets for Oil Sands Products**

Canadian oil sands projects will offset the overall North American decline in conventional light production and the expected increased demand for refined petroleum products. Traditional markets in Canada and the U.S (principally PADD II) will be extended to absorb extra production. For example, the production of ‘Synbit’, recently introduced as a blend of synthetic crude and bitumen, will likely increase from essentially zero to several hundred thousand barrels per day by the year 2010, because it is comparable to medium sour crudes.

The next biggest opportunity is PADD III in the southern U.S. The Energy Information Administration (EIA) has predicted that almost all the refinery capacity additions will occur on the Gulf Coast. Provided the issues of transportation and competition with foreign crude sources can be resolved, the U.S. Gulf Coast is an attractive and huge potential new market. Other new markets such as the Pacific Rim and southern PADD V (California), served via western Canadian ports, are currently thought to be as large as 1 to 2 million barrels daily in the medium to long term. Additional opportunities will be found in the shipment of more refined petroleum products.

Overall, it appears that there is sufficient market capacity and sufficient expanded end uses or internal energy needs to absorb the increased production. Understandably, the optimal mix of unprocessed bitumen and refined products will need to be continually adjusted to market needs.

**Upgrading and Fuels of the Future**

Upgrading not only provides an opportunity to increase the value of finished products, but also to respond to changing downstream refining pressures to produce cleaner burning fuels. This implies both flexibility in attacking “moving targets” as well as a capability to “leapfrog” to the crude quality demanded at some anticipated point in the future.

While the benefits and future potential capabilities of upgrading are substantial, many of the risks and costs will need to be managed to make added upgrading capacity in Canada an attractive investment.

**Pipeline Infrastructure**

Currently, up to 80% of heavy oil and bitumen blends produced in Canada are exported to the United States through existing pipelines. The bulk of this volume is sent to refineries in PADD II with the remaining volume going to refineries in other areas, notably PADD IV with imports provided solely from Canada.

There is currently estimated to be about two million barrels of daily pipeline capacity to move oil sands products out of the province, and a growing network inside the province to connect bitumen supply and upgraders. However, pursuing new markets will obviously necessitate an expansion in delivery systems.

Some of these requirements have already been anticipated with proposals for new capacity from Fort McMurray to Edmonton, and from Edmonton to the west coast for export to California and the Pacific Rim. Other proposals are targeting pipeline expansions deeper into PADD II and PADD III. The pipeline industry has entered discussions with oil sand producers to plan the right ‘mix’ of future capacity. In the case of finished products, the need to transport ultra-low sulphur products without major reprocessing is another potential development needing consideration.
Looking further into the future, pipelining of fuel gas, CO₂ for large scale sequestering and hydrogen for upgrading may all be elements of a fully integrated oil sands and associated pipeline infrastructure.

**Diluent Supply**
Unprocessed bitumen is currently shipped in pipelines by dilution with gas field condensate, typically in the 20-30% by blend volume range, seasonally adjusted to meet pipeline viscosity specifications. In some scenarios, where unprocessed bitumen shipments continue to grow, diluent requirements could increase from 95,000 barrels per day 2001 to more than 200,000 barrels per day by 2012. Diluent availability is currently expected to peak at around 200,000 barrels per day by 2004-2006, but decline in tandem with natural gas production thereafter.

However, the industry is already adapting. Where distances are shorter, such as connections between upgraders and bitumen supply, return loops can be justified. Alternatives to further reduce dependence on diluent might include heated pipelines, or blending with alternative viscosity reducers, such as conventional crude, synthetic crude (Synbit) and refinery naphthas. Other technologies may include emulsion pipelining or friction reducing agents. While not currently practiced, some partial upgrading in the field can be used to reduce or eliminate diluent demand. Lastly, full upgrading for a larger share of bitumen production will eliminate any consideration of diluent for this potion of production. In all, the industry will ensure that diluent supply does not hinder expanded oil sands development.

**Natural Gas Dependency**
Oil sands projects are heavily dependent on natural gas use for energy and power (co-generation) and hydrogen production for upgrading. In-situ energy demand with today’s technology requires 1000 cubic feet of natural gas per barrel recovered. Mining recovery demand is a more modest 250 cubic feet per barrel. Upgraders need as much as 500 cubic feet per barrel of synthetic crude for energy and hydrogen today, and this will climb as synthetic crude quality demands increase.

An extrapolation of natural gas usage by oil sands development to 2030, as based on current project natural gas rates for a reasonable mix of projects, is shown in Figure 2.3.

In this scenario, natural gas usage would rise from 10% of combined WCSB, Coal Bed Methane (CBM) and Mackenzie supply by 2012, to an unthinkable 60% or more by 2030. Such a demand level, combined with competition from other markets in the face of dwindling reserves, will only drive price increases. LNG imports into North America may begin to set price levels. The “business as usual” case is clearly unsustainable and uneconomical. The solution is energy and hydrogen self-sufficiency, either through the use of residues, or external energy alternatives, such as coal or nuclear energy.
The Environment - General Concerns

Concern for climate change has pushed compliance with the Kyoto Protocol to the forefront, but this is just one of the many environmental challenges. There are growing social and regulatory pressures to reduce the overall environmental footprint of the industry. More recently, concerns for the impact on the boreal forest have surfaced, as has the conservation of water.

While the environmental impacts of individual projects are extensively monitored, the cumulative effect of oil sands development and operations is relatively unknown. Appropriate non-technological (regulatory) and technological solutions will play an important role in assessing future oil sands projects, while ensuring that no irreparable damage is done to the environment. Additionally, the industry will need to invest in developing and applying the right technologies, not only to maintain but also to extend their existing environmental record.

Air Emissions

Air emissions from oil sands operations include carbon dioxide (CO₂), sulphur dioxide (SO₂), nitrogen oxides (NOₓ), hydrogen sulphide (H₂S), carbon monoxide (CO), methane and other volatile organic compounds (VOCs), ozone and particulate matter. Not only are there concerns regarding the atmosphere but also acid deposition in rain, snow and dust, as well as ground level smog.

Significant progress has already been achieved through industry’s response to the Voluntary Challenge & Registry (VCR) initiative. Industry’s use of low NOₓ burners and flue gas desulphurization to reduce SO₂ emissions, are specific examples of how the industry has responded.

However, the most critical air emissions issue facing the industry today is the implementation of the Kyoto Protocol (and beyond) and its potential impact on climate change.

The Kyoto accord specifically targets CO₂E (carbon dioxide equivalent) emissions. The industry has already shown a good record in reduced CO₂E emissions over the last decade (Figure 2.4).

Canadian Government base data estimate that the Large Industrial Emitters (including the Oil Industry) will emit 353 Mega-tonne per year CO₂E by 2012. The Federal Government target for reduction for the entire Large Industrial Emitters group by 2012 is 55 Mega-tonne per year. The Alberta government has proposed alternative approaches.

Figure 2.5 is an interpretation of the impact of oil sands development to the year 2030 under “business as usual”, and the potentially larger impact of using residues or coal for energy and hydrogen.
This "expectations gap" highlights the need to know the rules for industry beyond 2012 to ensure that long-term plans are not jeopardized by uncertainty. The CO₂E reduction challenge is clearly a very large one.

At this time, it is essential for the industry to seek and encourage development of greenhouse gas emission reduction strategies or technologies. Section 8 deals with the complete array of air quality issues in greater detail.

**Water Conservation**

Water usage has become an important concern in Alberta given consecutive years of drought, dwindling waters supplies and the rapid growth and expansion of industries and population. In response, the Government of Alberta has developed a draft water conservation strategy that identifies key initiatives such as water management planning and conservation.

Oil sands operations use water to separate oil from sand in the mining operations and to make steam for in-situ extraction. Smaller volumes are used in upgraders. In 2002, the Oil & Gas Industry was licensed to draw 4.1% of surface water, and 28% of groundwater. Alberta Environment does not require a license to withdraw saline groundwater.

Of the 438 million cubic meters of fresh water allocated to the Oil and Gas Industry, 138 million cubic meters (32%) is allocated to, but not necessarily consumed by, three oil sands projects near Fort McMurray. This usage could be considered from another aspect. By 2007, with four mining projects, consumption of the Athabasca River flow during winter months could increase to as much as 10% without changes to current practices.

The Oil and Gas Industry has made significant progress in water use reduction over the last several years as shown by Figure 2.6. The Canadian Association of Petroleum Producers (CAPP) has reported that use by the petroleum industry is monitored at less than 50% of their allocations.
There are also trends to use brackish water in place of fresh water. The industry must continue to strive for minimum water use and maximum reuse. New technologies in mining recovery, tailings management and in-situ recovery processes will assist in achieving that goal.

**The Environmental Footprint & Land Reclamation**

There is a need and desire by the industry to employ sustainable development to limit the environmental footprint and to promote land reclamation. In fact, this has been a large issue for the mining operations for many years. Technological advances have helped in the management of tailing ponds. For example, the development of tailings consolidation technologies is aimed at reducing the time for water release and reuse as well as permitting a smaller disposal area.

The growth in oil sands production is also putting pressure on the optimization in the use and conservation of the boreal forest. Tree clearing for operations often means tree harvesting in non-optimum ways. This has the potential to bring the industry into direct conflict with the forest industry that is charged with long-term planning and forest regeneration. Nonetheless, there are initiatives in place to ensure that the two industries co-exist in a sustainable fashion.

The future must involve a more integrated approach to oil sands exploitation, recognize limits to physical development, and embrace cumulative effects planning. An integrated approach encompasses the complete ecosystem and includes all stakeholders to increase information flow, cost efficiencies and planning.

**Sulphur Production**

Bitumen contains on average close to 5% by weight sulphur. The removal of sulphur (desulphurization) occurs during various upgrading processes, and is recovered, via hydrogen sulphide gas scrubbing. Recovered sulphur is either stockpiled or shipped to markets.

Suncor and Syncrude recovered approximately 1 Mega-tonne in 2002, about equivalent to 2 Mega-tonne per year for each million barrels daily of full bitumen development to synthetic crude. This is in line with EUB predictions of another 2.2 Mega-tonne per year by 2012. If the industry moves to use residues or coal for energy and hydrogen, this figure could climb to some 3 Mega-tonne per year for every million barrels per day of synthetic crude production. A “mixed product” industry might therefore be producing anywhere from 10-12 Mega-tonne per year by 2030, depending on the extent of full upgrading in Canada by that time. Putting this into current context, it is equal to about half of the internationally traded sulphur worldwide, and is almost double Canada’s seaborne exports today.
KEY CHALLENGES FACING THE INDUSTRY

The handling of sulphur from oil sands production is a challenge, given the global glut of sulphur, the high cost of transportation from our landlocked supplies, and continuing non-discretionary production from natural gas and refineries. New technologies to use the sulphur by-product in non-traditional ways, such as in cement, sulphur enhanced road asphalt, as well as in plant nutrient demand growth, all offer ways to mitigate the world supply-demand imbalance. However, the oil sands industry needs to deal with medium to long-term storage.

Coke Product
The current mine operators use a ‘coking’ process as the first step in upgrading bitumen to synthetic crude. The product coke efficiently captures some of the sulphur and the heavier, more difficult hydrocarbons in the bitumen prior to upgrading. However, it is both a high tonnage, low value product, and the management of this product is a continuing challenge. Any future coking-based upgraders will need to consider how they will deal with coke production.

The Syncrude coke is currently placed back in the older mine areas, segregated for potential future use as fuel or for hydrogen production, if and when economics for this end use improve. Suncor and Husky Lloydminster upgraders deal with their coke in a variety of ways. Some is burned for energy. Some is sold for power production or other uses, at zero (or more likely negative) netbacks. The balance of this coke is stock-piled today.

Downstream refiners operating the same coking units to process residues or diluted bitumen share the same disposal challenges.

Other future trends to non-coking based upgrading, or use of residues or coke for energy, power and hydrogen production, will move towards industry-based solutions to this issue.

Construction Costs and Trade Skills
Recent experiences with major project cost overruns within the industry have caused much concern. One of the recent contributory causes has been attributed to a shortage of, and subsequent competition for, skilled personnel for a large number of projects being developed within the same timeframe.

In response, the Construction Owners’ Association is working with industry, labour and technical institutions in an attempt to ease these problems. In addition, the Construction Labour Relations Association of Alberta has been instrumental in the collaborative production of an annual forecast for the construction trades.

Industry has also responded by breaking up huge projects into smaller elements, doing more of the engineering drawings in advance, while interacting in real time with vendors and fabricators. More sophisticated use of shop fabrication is becoming the norm, with smaller process modules to minimize field construction and maintenance. Current expansions are being monitored to see if these measures will significantly improve the performance.

Construction trade skills are not the only area for attention. Increasingly sophisticated equipment will demand that training programs adapt to the changing operational needs.

The main body of the Technology Roadmap
Sections 3 through 9 deal with the technology development requirements, or technology gaps that need to be filled, to make the vision of oil sands production expansion a reality. Section 10 highlights the actions that must be embraced to bring industry, governments and R&D providers together to ensure a coordinated and well funded technology development plan. Section 11 focuses on the societal issues for all of Canada that will need to be addressed.
3. MINING-BASED BITUMEN EXTRACTION

Entirely new concepts that revolutionize mining recovery are under review, but water-based bitumen extraction processes are expected to dominate to 2030. There are many opportunities to improve on processes the mining industry uses today. A recent example is the first commercial application of paraffinic-solvent based froth treatment, to produce bitumen with improved characteristics.
This section deals with Surface Mining technology up to the diluted bitumen stage. Upgrading technologies are discussed in section 6. In addition, main environmental challenges are covered in sections 5 and 8.

**Surface Mining & Extraction Today**

Figure 3.1 depicts operating costs for mining and water-based extraction today. At around $8 per barrel, the combination represents about 50% of costs from mine to synthetic crude. Capital costs for mining extraction will add about $3-4 per barrel (see report forewords for the basis of capital estimates).

The overall recovery of bitumen from the mined sand is another important factor not reflected in the cost structure. The recovery with today’s technology is about 87-90+ %, but is strongly ore-quality dependent. EUB require oil sands operators (under EUB ID-2001-07) to achieve 90% recovery with 11% by weight (or better) ore quality. Figure 3.2 shows where typical losses occur, bearing in mind variable ore quality, and ongoing improvements in most areas.

The losses of bitumen in the processing operation come from oversize rejects and other mining activities (2-3% of all losses), primary bitumen recovery to the bitumen froth stage (6-8%) and the diluted froth treatment for bitumen recovered (2%). The major causes of loss include instability in operation, variable feed grade, effect of winter conditions, water chemistry, mechanical reliability, and improper slurry conditioning for some ore types.

The figure quoted for froth treatment does not reflect the newer paraffinic solvent froth treatment process. This process deliberately rejects additional selected heavy components to tailings, and the level is not published, but is expected to be between 4-8%.
Key Challenges for Mining Based Operations

A number of the challenges from Section 2 that directly face the mining based oil sands recovery industry are summarized in Figure 3.3. Most environmental issues are covered in Section 5 (Water and Land use) and Section 8 (Air Emissions).

FIGURE 3.3 KEY CHALLENGES FOR MINING BASED OPERATIONS

> Cost of operations, maintenance
> Overall recovery
> Quality of extracted bitumen & market acceptability
> Water use

Dealt with in other sections
Energy use & natural gas dependence
Air Emissions
Environmental footprint

Because mining technology and the associated extraction processes (and challenges) are different, they are dealt with separately. However, one can influence the other, and where there are direct links between the two steps, they are duly noted.

Surface Mining Technology Today

The typical state-of-the art surface mining operation in oil sands (see figure 3.4) includes the following operations:

> Removal of overburden with truck and shovel operation. Generally overburden is disposed of in-pit but some is moved to out-of-pit dumps and some is used to construct containment structures for tailings.
> Mining oil sand with electric or hydraulic shovels.
> Transport of oil sand from the mine face to crushers with trucks.

> Crushing of oil sand from run-of-mine down to around minus-12” size.
> Slurrying of oil sand with various devices.
> Transporting of oil sand from the mining area to the extraction site using centrifugal pumps and pipelines (generally referred to as “hydrotransport”).

While the design of mining equipment and certain mining operations are unique to the industry, the operations are currently constrained to take into account technology limitations in subsequent extraction processes. The extraction step is also the source of the largest bitumen losses. In this respect, there are integration issues that need to be considered between the mining and extraction steps.

Recovery of bitumen today is in the order of 97% of the bitumen on mined sand (Figure 3.2) with losses to large indigestible lumps or general spillage. It is not anticipated that this can be greatly improved.
Mining costs are summarized in Figure 3.1 and the associated text. Major factors affecting operating costs include:

- Ore grade
- Overburden volumes
- Cost of energy
- Material handling distances
- Maintenance

The last of these - maintenance - is about 50% of the operating costs.

Continuous Improvement Opportunities in Surface Mining Operations

It is anticipated that costs for the basic mining steps as practiced today can be reduced by research in areas summarized in Figure 3.5 and discussed below.

**FIGURE 3.5 SURFACE MINING CONTINUOUS IMPROVEMENT**

- Purpose designed equipment
- Materials handling
- Decision support systems
- Sensors / real time control
- Improved materials
- Maintenance procedures
- Improved machine health monitoring systems

> Equipment that is better designed for specific use in the oil sand industry. There are a number of improvements that can be considered, from tire technology, the development of lighter and stronger vehicles through materials technology, and maintenance practices. Generally, the industry needs mobile equipment better suited to the soft ground conditions.

> Material handling systems that reduce handling and/or transportation distances.

> Decision support and information systems that allow more optimal mining decisions

> Sensors that meet the specific needs of the industry (e.g., tramp metal detection, lump size measurement in real time, monitoring equipment for wear/failure, etc)

> Improved materials to meet unique industry needs

> Improved machine ‘health’ monitoring systems that are better able to anticipate failure and support preventative maintenance procedures

Surface Mining Technology Tomorrow

For oil sand reserves with less than 50 meters of overburden, it is not expected that there will be any alternative to surface mining options that could be developed by 2030, although this should not stop the search. Overburden will still need to be stripped to expose the ore body, and oil sand will still have to be mined and processed in a water-based extraction process. In addition to continuous improvement opportunities noted above, there are potential step-out developments that could radically alter mining operations within the 2030 time frame:

**FIGURE 3.6 SURFACE MINING STEP-OUT TECHNOLOGIES**

- Tailings technology
- Dry tailings
- Mobile conditioning equipment
- Mining equipment design for improved extraction
- Borehole technology for intermediate reserves
- ‘At face’ continuous mining
In more specific terms:

- **Tailings consolidation** technology, through better understanding of fines and chemicals use.
- **Dry tailings disposal technology** (see Section 5) will use up in-pit volumes currently used for overburden disposal and could eliminate the need for overburden to be used for construction of tailings containment structures. This may present opportunities for out-of-pit overburden disposal not requiring mobile equipment.
- **Mobile** crushing, slurring and bitumen extraction equipment will reduce material handling distances.
- A Bitumen extraction process that is more tolerant of ore variability (discussed later in this section) will have significant implications for the design and operation of mining systems. This will reduce blending, stockpiling and over-design of equipment.
- Can some form of horizontal ‘borehole’ technology be developed to access the reserves between 50 and 150 metre depth?
- Oil Sands continuous mining and extraction equipment, such as the Tar Sand Combine, which has had recent trials. Can this kind of equipment be developed to commercial operation?

The remainder of this section deals with bitumen extraction processes associated with mining-based recovery.

**Mining-Based Bitumen Extraction Today**

In the last fifteen years, hydro-transport has replaced other conditioning equipment. The extraction of bitumen from the conditioned ore slurry now consists of two main steps:

- Separation of bitumen froth (60% bitumen, 30% water and 10% fine solids) in the primary separation vessel (see Figure 3.4).
- Diluted froth treatment (Figure 3.7) to recover the bitumen and reject as much residual water and solids as possible. In this step, there are two current approaches. The original naphtha solvent based process requires inclined plate separators and centrifuges to remove residual solids and water. The newer process with paraffinic solvent adds other process vessels, but eliminates high maintenance centrifuges and results in a cleaner product.

From the hydro-transport step forward bitumen extraction recovery efficiency is 90-92% on original bitumen. Of the 8-10% lost bitumen, 6-8% reports to the sand and clay tailings from the primary separation vessel (PSV). A further estimated 2% is lost at the naphtha diluted froth treatment step, with the original separator and centrifuge based recovery. Recovery improvement
to around 95% for this combination is considered an achievable medium to long-term target.

With the newer paraffinic solvent froth treatment process, there is an added but planned ‘loss’. This loss is not bitumen, but is rejected asphaltenes (in the range of 4-8% by weight of bitumen) which report to the tailings. This is discussed further below.

Continuous Improvement Opportunities in Mining Based Extraction

Mining based bitumen extraction costs today (Figure 3.1) are estimated to be in the order of $3-$3.50 per barrel of bitumen (including PSV operation, froth treatment and tailings placement, but excluding tailings reclamation). Labour is around 25% of the overall costs.

Figure 3.8 summarizes areas for improvement in the Primary Extraction and Froth Recovery processes in operation today.

Primary Extraction

Mining based extraction processes will benefit from improvements in the operation of the primary separation step (PSV), where 6-8% of mined bitumen is currently lost to tailings. The PSV is a large, expensive, fixed and inflexible process vessel. It needs steady state conditions and is sensitive to even mild changes in ore grade, temperature, feed rate, and other conditions. The need for a process temperature of greater than 35°C imposes a demand for energy that approximates 40% of the total energy consumed in producing a barrel of synthetic crude oil. The process also requires caustic addition to control pH to around 8.5, causing corrosion in material handling equipment.

Apart from operational challenges, bitumen product from the combined PSV and naphtha based froth treatment and dilution centrifuging has a BS&W (bottoms sediment and water) level of 1-2%. This creates problems such as corrosion, plugging and catalyst deactivation in downstream operations. It also renders the bitumen product unsuitable for refinery feed stock.

Improvement opportunities at the PSV stage include:

> Increased mechanical availability, through better preventative maintenance techniques and improved materials.
> Tailings re-processing to recover more of the bitumen and solvent currently lost to tailings.
Sensitivity to both ore quality and the amount of clays the PSV can tolerate imposes a need for *selective mining and blending* to smooth out variations at the PSV.

*Well conditioned slurry* is required under very variable ore conditions. The water based process requires clays to be well dispersed, which “locks up” large volumes of water which then have to be stored in tailings.

*Reduced sensitivity to process temperature.* There are two issues here. The temperature level of current PSV operations represents a high energy need. Secondly, research and development is needed to reduce sensitivity to temperature fluctuations that impair smooth PSV operations. Advanced sensors and process control (discussed under “Extraction Technology Tomorrow”) are also desired objectives.

Overall, a greater understanding of effects of *water chemistry* on the PSV operation is needed.

Other areas for cost reduction in extraction and associated tailings steps include:

- *Centrifugal pump parts and repair.* Component life needs to be extended to match the life of other major components of the hydro-transport train.
- *Tailings pipe maintenance* and replacement. Tailings pipe life today is perhaps 2-3 years. Pipe life in excess of 10 years would be desirable.
- *Reduced caustic use,* which directly impacts tailings pipe life.

**Froth Treatment**

Bitumen produced by the original naphtha solvent based dilution centrifuge process (as practiced by Suncor and Syncrude) has approximately 0.3-0.5% solids and 1-2% water. This makes it unsuitable for pipelining and direct sale to traditional refineries. This inability to sell product directly to the open market has been one impediment to the surface mining sector of the oil sand industry.

Opportunities for improvement are identified in Figure 3.8. for the original centrifuge-based diluted froth recovery and include:

- *Centrifuge parts* and repair (or the elimination of centrifuges altogether).
- *Improved water and solids removal* techniques that do not rely so heavily on *demulsifier* usage.
- Means to incorporate *paraffinic solvent* recovery science and learnings to further develop the centrifuge-based process.

An objective here is to recognize the major investment in the current naphtha-based process equipment, and develop means to retrofit existing plants to improve bitumen quality.

The Shell-led Albian Sands project has recently commercialized a process using paraffinic solvents. This has resulted in the production of a pipelineable bitumen that is lower in asphaltenes and very low in BS&W, and can more easily be blended with other refinery feed stocks. The process also eliminates the need for centrifuge operations, but at the expense of other settling vessels, with a large plot size. The industry recognizes the Albian Sands plant is only the “first generation” of this approach. The Fort Hills project (currently shelved) planned to use similar science, but incorporated further developments to reduce capital and operating costs.

The paraffinic solvent based process opens up some product flexibility for the surface mining sector of the industry and allows that part of the industry to compete directly in the open market with bitumen from *In-Situ* production.

Any advantages of this new approach to froth treatment are less certain for currently operating integrated upgraders, as a substantial part of the hydrocarbon feed to upgraders is lost to tailings (the asphaltene portion). However, this in turn also makes the asphaltene-reduced feedstock more easily upgraded in certain primary
MINING-BASED BITUMEN EXTRACTION

processes (as discussed in Section 6), and does eliminate fines carry over to secondary upgrading processes. The balance between these factors is not yet fully understood or researched.

Opportunities for improved understanding, and design and operation of the new paraffinic based diluted froth recovery include these factors.

> The clarifiers used by the Albian Sands project use large plot space, and are relatively capital intensive in this first generation plant.
> Optimization of process conditions is not fully understood. Research is needed into process variables such as solvent/bitumen ratio, pressure and temperature, all as a function of improved bitumen quality.
> Understanding the balance between this improved bitumen quality, but lesser volume, on primary and secondary upgrading processes is not well known.

A viable target to aim for in combined extraction, froth and tailings placement is a 50% reduction in non-labour costs (or $1.20 per barrel) if appropriate solutions to today’s concerns are developed. Significant reductions in labour costs are not expected with the current technologies in use.

**Bitumen Extraction Technology Tomorrow**

Unless new concepts such as the Tar Sand Combine develop and “revolutionize” mining recovery, there are no major breakthroughs or alternatives to the water based bitumen extraction process likely to emerge in the time frame of the Roadmap. Solvent based or retorting processes operating on the full mined oil sand stream appear unlikely to provide significant advances over the current approach before 2030. Figure 3.9 lists some longer term developments that are considered achievable.

**FIGURE 3.9 EXTRACTION STEP-OUT TECHNOLOGIES**

> Reduced water use
> Reduced bitumen losses to tailings
> Movable equipment
> Less mechanical / thermal intensive
> Advanced Sensors / real time control
> Enhanced reliability / less sensitive to transients

The greatest advances in the future will come from the reduction in the negative influences extraction can have on the upstream and downstream processes. These can be addressed through the following research directions:

> A process that has a greatly reduced net water usage.
> Bitumen separation processes that are more efficient, with reduced hydrocarbon losses (bitumen and any process solvents) to water and tailings.
> The size and fixed nature of the PSV increases the material handling distance as oil sand has to be moved from the face to the PSV and then to tailings. A distributed and moveable extraction process would reduce material handling distances.
> Processes that require significantly less mechanical and thermal intensity need to be sought and researched.
> **Advanced process sensors and real time process control** from mine to recovered bitumen.
> Higher reliability components, and more robust extraction processes that are less sensitive to transients, such as grade, fines, water chemistry, and so on.
MAJOR PROJECTS IN COLD LAKE AND PEACE RIVER SITES HAVE BEEN EXTRACTING BITUMEN BY IN-SITU THERMAL TECHNIQUES FOR MANY YEARS FROM DEEP, HIGH QUALITY RESERVES. MORE RECENTLY, ADVANCED HORIZONTAL DRILLING TECHNOLOGY HAS LAID THE FOUNDATION FOR STEAM ASSISTED GRAVITY DRAINAGE (SAGD), BRINGING A WIDE RANGE OF THINNER RESERVES INTO POTENTIAL DEVELOPMENT, WITH DRAMATICALLY INCREASED RECOVERABLE RESOURCE POTENTIAL. SAGD AND FUTURE VARIANTS HOLD GREAT PROMISE FOR THE INDUSTRY’S EXPANSION.
In-Situ Production Today

Bitumen can be recovered today by various in-situ techniques. In some favourable situations 12˚+ API bitumen can be produced by primary production via foamy oil and worm hole mechanisms, although the recovery is low, around 5 to 10% of bitumen in place. For greater recovery and lower API bitumen, steam injection at relatively high injection pressures is required. One mature process for deep, thicker reserves, such as in Cold Lake and Peace River, involves cycling at single vertical injector/producer wells (this is sometimes referred to as “huff ‘n puff”). An alternative incorporates steam drive between injectors and producers. While these processes originally depended on vertical well, combinations of vertical and horizontal wells are now used.

High injection pressures for deep, “huf’n puff” processes require an overburden cover of 300 or more meters. Resource recoveries using this technique are in the range of 20-35%, and typical steam/oil ratios, the major economic factor, are 3 to 4.

Advanced horizontal drilling technology laid the foundation for steam assisted gravity drainage (SAGD). The process in various forms has been extensively piloted, and in some cases commercialized, by several companies. SAGD brings thinner reserves into the recoverable reserve category. SAGD works best in high permeability reservoirs, resulting in lower injection pressures and lower steam/oil ratios. In a SAGD operation, several horizontal well pairs are drilled from the same pad extending as long as 1,000 meters horizontally into the oil sands and about 5 meters apart vertically. The top well is used to inject steam to warm up a zone around and below the injector, reducing the viscosity and mobilizing an expanding zone of bitumen, which is then produced through the lower well.
Figure 4.2 depicts typical SAGD supply costs for high grade reserves. Steam oil ratios of SAGD in high quality reservoirs are in the 2.5:1 range.

Variable recovery cost is estimated at about $7.40 per barrel, for high quality reservoirs, slightly lower than surface mining operations. However, sensitivity to energy prices is high compared with surface mining. Ultimate recovery is anticipated to be in the 40-70% range. Unlike mined bitumen, product is generally low enough in BS&W to be handled conventionally in downstream refineries, with due attention to higher acid numbers.

Capital charge per barrel is in the $3 range, with much of the capital for drilling spread over the life of the project. (see report forewards for the basis of capital estimates).

There are many other advantages of in-situ recovery over mining operations.

> Modest size for commercial SAGD operation allows introduction of new technology in smaller steps with lesser business risk than for mega-mining ventures.

> Much smaller development ‘footprint’ means the inventory of disturbed land is much smaller.

> The inventory of process-affected water is much smaller than mining, eliminating on site containment.

> The demand for workforce is much lower than mining and can be satisfied from conventional oil and gas operations, currently in decline.

> The majority of the oil sands reserves are too deep for ‘open pit’ mining.

SAGD is still ‘on the learning curve’ in terms of technology development.
Key Challenges for In-Situ Based Operations

Figure 4.3 summarizes the key challenges that need to be addressed for In-Situ operations.

FIGURE 4.3 KEY ISSUES FOR IN-SITU
- Markets for product
- Energy use & natural gas dependence
- Diluent for transport
- Overall recovery
- Water conservation

Dealt with in other sections
Air Emissions
Environmental footprint

One paramount issue is to develop new markets for the increasing amount of new production. Another is the high energy required to stimulate the reservoir. Unlike mining, energy consumption in In-Situ is more closely associated with the basic technology and variants under consideration. Alternative energy options are therefore covered extensively in this section, as well as in Section 7.

Bitumen netbacks are eroded by the premium paid to acquire condensate for blending bitumen to make diluted bitumen (“DilBit”). The alternative to condensate is to blend bitumen with synthetic crude to make “SynBit,” which could reduce blending stock costs, and appeal to a wider market for conventional medium sour crude. In addition, if SAGD production is to expand greatly, much of the new production will need to be upgraded to higher value products.

In-situ operators also need to switch from using fresh water to brackish water as a means of water conservation.

In-Situ Recovery Technology Today

SAGD operations can be economically viable at production levels as low as 10-15,000 barrels per day, and can be “staged” for gradual stepwise production increases. Figure 4.4 depicts the main aboveground operations in a typical SAGD project.

The surface facilities consist of water treatment plants to produce boiler feed water (BFW) from steam condensate or brackish water produced from local aquifers. Once-through steam generators or co-generation plants provide steam for injection into the reservoir. The oil is easily separated from the produced emulsion by blending with condensate and treating with chemicals at elevated temperature. The clean DilBit is shipped by pipeline to market.
Continuous Improvement Opportunities for In-Situ Technologies

There are a number of opportunities to improve “huff ‘n puff” and SAGD technologies.

FIGURE 4.5 IN-SITU CONTINUOUS IMPROVEMENT

> Energy …lower steam/oil ratios
> Alternative Energy …internal and external
> Solvent assisted recovery
> Reliable down hole pumps
> Multi-phase flow measurement
> Water reuse
> Reservoir simulators
> Steam chamber growth tracking
> Drilling technology
> Pipeline transportation
> Gas-over-bitumen reserves
> Shallow/ more marginal resources

Dealt with in other sections
Greenhouse Gas emissions/sequestration

> Reducing the high energy demand for thermal recovery is tied to reducing steam/oil ratios.
> Dependence on natural gas is an industry wide challenge. The obvious alternative is to use some of the bitumen production, or the residue portion, in state-of-the-art boilers with emission controls, such as stack gas scrubbing. Alternative ‘external’ sources are coal or nuclear energy. Section 7 provides more discussion on this. Partial oxidation-based Gasification is also reviewed in section 7. It is a known technology to convert residues to hydrogen and energy, but will need significant cost reduction if it is to compete with combustion to produce fuel alone.

> Solvent processes alone (such as VAPEX), or solvent assisted SAGD, where steam and solvent work together, are under pilot evaluation today. Both potentially offer lower energy intensity and access to shallower resources.

> More reliable down hole pumps will among other things help to resolve gas over bitumen issues as well as access to shallow In-situ bitumen resources.

> The development of better multi-phase flow measuring devices for water, oil and gas production mixtures would improve operations control.

> Better water recycle and reuse technology will reduce net draw on fresh water sources.

> Improved reservoir simulations will allow better prediction of overall reservoir performance as well as help to train the next generation production technologists.

> Steam chamber tracking technology will lead to more targeted steam injection policy, and improve reservoir recovery.

> Horizontal drilling technology improvements will help reduce capital and allow more accurate well placement.

> Water/oil emulsions may play a role in transport or combustion. Emulsion-based bitumen products from Venezuela have been marketed for many years. Other attempts have been made in the past to develop stable emulsions for pipelining.

Generally, In-Situ technology needs to progress to help develop more marginal reserves. In addition, ways to overcome the recent “Gas-over-Bitumen” issue need to be considered.

In-Situ Recovery Technology Tomorrow

Some of the developments identified above for continuous improvement may also extend to the longer term. Other developments, clearly requiring long lead times to commercialization have also been identified.
Over many years, a number of In-Situ processes have been proposed that incorporate co-injection of oxygen to promote some form of in-situ combustion or gasification. This produces the energy to warm up the reserve and mobilize the bitumen. Details such as the impact of a fire front on the produced bitumen, controlling the fire front, and so on have not been fully addressed at this stage, and many years of piloting will be necessary. Processes such as Texaco fire-flood (an early proposal), THAI™ and SUPOX are among those processes being advanced as candidates. The “toe to heel air injection” (THAI™) process has been extensively researched in the UK and Canada, and is scheduled to be field piloted in 2004.

The use of catalysts in production strings, such as is proposed in the CAPRI™ process (a modified form of THAI™) might offer in-situ upgrading to help promote easier production with less energy.

New low or non-steam approaches to mobilize the reservoir, via combined electrical induction and solvent, or microwave energy, may be more energy efficient, and more adaptable to the intermediate and mining depth reserves.

Microbes that work underground to reduce viscosity or partially upgrade bitumen in-situ prior to production may be developed within the timeframe of this roadmap.
5. SUSTAINABLE DEVELOPMENT ON THE GROUND

THE ENVIRONMENTAL ‘FOOTPRINT’, PARTICULARLY FOR MINING OPERATIONS, PUTS RESPONSIBILITY ON THE INDUSTRY TO MANAGE THE RESOURCES WE USE OR DISTURB, ESPECIALLY LAND, WATER AND NATURAL GROWTH, IN A RESPONSIBLE WAY. WHEN COMMERCIAL DEVELOPMENT CEASES, THE LAND MUST BE RETURNED TO THE COMMUNITY AS A FULLY SUSTAINABLE ECOSYSTEM.
Oil Sands Industry Land and Water Practices Today

The cumulative effect of oil sands operations needs to be managed, and non-technical (regulatory) and technological solutions will be important in assessing future oil sands projects. The industry must invest in developing and applying the right technologies to reinforce a strong environmental record.

The environmental ‘footprint’ discussed in this section is defined as land and water use, land reclamation, and associated challenges.

The special needs for handling other products (coke, sulphur and others) that need to be managed by any integrated mining and upgrading plants, are discussed in section 6, as they are the direct result of upgrading, not mining operations. Air emissions are dealt with in Section 8.

With these exclusions in mind, technologies affecting and managing sustainable land and water use by the oil sands industry differ widely for Mining and In-Situ producers, but have some common themes.

Water use has become an important issue in Alberta. Water use was also discussed in Sections 3 and 4 in connection with extraction energy use and associated costs. In response to the province wide concerns for fresh water, the Alberta Government has recently developed a draft water conservation strategy which will affect future oil sands projects.

Technologies that can help reduce water use are:

- new extraction technologies that reduce water consumption per unit of bitumen produced (dealt with in Sections 3 and 4), or
- technology that helps to capture and recycle water for reuse, reducing the draw on fresh water sources.

The current mining operations (Suncor, Syncrude and Albian Sands) and the expected addition of CNRL by 2007, plan to draw as much as 10% of the Athabasca River flow in the low-flow winter months. The used process water is recovered in tailings ponds. Slow solids settling and water clarification currently limits major potential for process water recycling (including thermal value).

Solids handling is a greater issue in the mining sector. The nature of any surface mining operation leaves a large and highly visible footprint, compounded by unique factors in the oil sands mining industry today. The area currently used by oil sands mines is large.

The major challenge for more sustainable operation is in the way land is reclaimed when industrial activity ceases. As noted in Figure 3.1, the two largest contributors to land recovery are overburden removal and disposal, and tailings management, which together account for $2.50 of costs per barrel of bitumen recovered (about...
The long-term objective is to return lands to as close to their natural habitat as possible in the 10 to 50 year timeframe. This leads to the need for expertise in such areas as soil reclamation for plant growth, and the reestablishment of wild life.

Solids handling issues for In-situ recovery are relatively less onerous, and concern the small amounts of produced sand and other solids, recovered as site sludge.

A more recent issue is the clearing of boreal forest for access to production sites. It is estimated that within the oil industry operating regions, some 3% of the land has been cleared of trees. Technology solutions for the oil sands industry are indirect here, but industry actions require close coordination with the forestry industry and their forest management plans.

Technology development opportunities and needs are discussed for Mining and In-Situ recovery separately.

**Mining Based Footprint Today**

Operations today that impact land, produced solids, and water management are depicted in Figure 5.2.

Firstly, overburden must be excavated and disposed of permanently, initially in above ground uses (such as containment berms for tailings ponds) and subsequently in the mined pits, when space becomes available. Current industry practice is to use large off-road haul trucks, which deposit overburden, with some later compaction.

Exposed oil sands are mined, transported and extracted by processes described in Section 3. As an approximation, for every cubic metre of synthetic crude oil produced, there are 6 cubic meters of sand and 1.5 cubic meters of mature fine tailings to be transported by slurry pipelines to the tailings management area.

Upon discharge, the coarse solids settle quickly to form saturated sand deposits that are also amenable to terrestrial reclamation. The water with suspended fine solids (silt and clay) - known as fine tailings - are pumped to a settling basin. This is the so-called tailings pond, easily visible in Figure 5.3, a satellite picture north of Fort McMurray, including the footprint of Suncor, Syncrude and Albian Sands plants.
Process-affected water is impounded in these ponds. The fine solids settle very slowly, and the resulting clarified surface water is recycled back to the extraction process.

As the mature fine tailings (MFT) become sufficiently concentrated they must be contained in land and aquatic forms according to published lease closure plans. Current practices for long-term storage of “fluid” fine tailings pose a risk to the oil sands industry. It is likely to come under increasing scrutiny from all stakeholders including regulators, operators, owners, local groups, and the regional municipality of Wood Buffalo. Suncor and Syncrude are utilizing consolidated or composite tailings to consume MFT. In this technique MFT and a coagulant, gypsum, is added to coarse tailings cyclone underflow. The resulting non-segregating mixture is pumped out to the tailings management area where water is readily liberated leaving the MFT entrapped between the sand grains. These deposits are contained at this time and pose a reclamation challenge.

In reviewing technology development needs for current or future operations, it is noted that process water reduction potential via new extraction technology was dealt with in Sections 3. Such extraction water reduction will positively impact reclamation and water handling issues generally.

**Continuous Improvement to Reduce the Mining Based Footprint Today**

The overall size of the mining footprint likely cannot be substantially reduced, but the active area of disturbance can be reduced by innovative approaches. Such improvement is closely related to overburden and tailings management (especially the fine tailings), and the operation of the tailings ponds.

All industry stakeholders have a preference for self-sustaining terrestrial reclamation. However, aquatic based reclamation, characterized by water capping of fine tailings, is still considered by some to be viable and appropriate for specific planning purposes. So there are two possible ways forward for tailings management, in part depending on how alternative technologies develop:

- Managed disturbance, with minimal adverse impact on adjacent undisturbed environment, with a commitment to acceptable reclamation at a future date. This is current industry practice and is thought to be the lowest cost today. In this case, large tracts of land may exist in a disturbed and unreclaimed state for many decades. This approach has the advantage of allowing time for the disturbed areas to establish a new stable condition, drainage networks to
become established and evolve, and tailings process-affected waters to be flushed out by natural precipitation

> Accelerated tailings dewatering and reclamation technology. This could result in significant environmental improvements, such as the elimination of new tailings ponds, adopting strip mining techniques and implementing progressive reclamation. This should be undertaken under the umbrella of regional cooperation.

With respect to tailings water management, the present industry strategy uses tailings ponds as multi-functional units, incorporating four needs:

- fines settling to produce dense fine tailings (MFT)
- coarse solids (sand) disposal
- process recycle water clarification
- act as a heat sink for some aspects of operations

Figure 5.4 lists the areas that appear fruitful for further technology development. Each is discussed in turn.

> Tailings pipes and pumps have high failure rates, which results in high maintenance downtime and costs. New materials and better pumping technology will reduce maintenance and replacement costs.

> The current industrial practice for modifying fluid MFT is to add a coagulant (gypsum) and co-dispose with dense coarse tailings (sand). By filling the sand voids with fine tailings, water is released for reuse and the overall fine tailings volume reduced. The process is known by several names - Non-Segregating Tailings, Consolidated Tailings and Composite Tailings. Albian Sands uses an anionic flocculant in thickener vessels to produce a densified underflow that is similar to MFT. These techniques address the large inventory of fluid fine tailings but are predicated on sufficient coarse tailings being available and the acceptance into the final landscape of large volumes of potentially liquefiable sand. More research is needed.

> Promoting accelerated fine solids settling in the tailings ponds will allow more rapid process water recycle and less fresh water draw.
Mining Footprint Technologies for Tomorrow
There are a number of longer term technology development needs for future solids and land reclamation management. Figure 5.5 is a summary of the major ones identified.

FIGURE 5.5 FUTURE TECHNOLOGY DEVELOPMENT

- overburden hydrotransport
- stackable coarse tailings
- rapid fine tailings dewatering
- by-product opportunities
- land reclamation / restoration / rehabilitation technology

Dealt with in other sections
Water reduction in extraction

Dry tailings will use up in-pit volumes currently used for overburden disposal. It may in future be possible to co-mingle the overburden with mature fine tails, helping to consolidate this stream more quickly. This is essentially overburden hydro-transport, and has the potential to eliminate the current high cost use of trucks for transport.

Hydraulic disposal of coarse tailings results in deposits saturated with process affected water and a fines-rich runoff. This runoff needs to be collected and managed. Placement of dewatered sand (cyclone stacking or filter/conveyor) would reduce process affected seepage water over time. It would also provide new operational opportunities supporting more rapid and progressive reclamation.

Fine tailings consolidation technology needs to advance further. Rapid dewatering of fine tailings, in equipment such as thickeners, would be a key for improved tailings practices, including drying of densified fine tailings in sub-aerial drying beds. The clarification function of the tailings ponds could then be substantially reduced or even eliminated. CO2 injection has potential as a coagulant to improve tailings management practices - a synergistic benefit with greenhouse gas reduction, albeit with only minor sequestration capacity.

By-products from discarded tailings, such as heavy minerals and kaolin are commercial products currently available in significant quantities in other parts of the world. Although the markets exist, the challenge is to identify champions to progress the initiative in the oil sands.

After reclamation, reinstatement of a sustainable surface hydrological regime will be challenging. In addition, backfilled mines will essentially be above the level of Athabasca River and its tributaries, and over the long-term process-affected seepage water may re-enter the river system. The environmental impact of such water seepage requires additional R&D to allow for effective management.

This concludes the review of the mining based footprint and ways to improve performance in the future. The less onerous challenges facing the In-Situ footprint are now discussed.

In-Situ Footprint Today
In-situ bitumen recovery has a much smaller footprint to manage. Figure 5.6 is an aerial view of EnCan’s Christina Lake commercial surface facility measuring about 1 square kilometer. This area is large enough for 95-125,000 barrels per day of production. Several horizontal wells drilled from one pad have helped to reduce the disturbed ground area for injection and production wells.
As noted earlier, forest clearing practices do not have technology implications for the oil sands industry, but need to be managed more cooperatively with the forest industry in future.

Because water for steam generation is largely recovered with bitumen produced, and is continuously treated and recycled, net water consumption for In-Situ production is considerably smaller than for the mining operations. In-situ projects can typically recycle more than 90% of the water, for a net loss of less than 0.2 to 0.3 units per unit volume of bitumen. The brine resulting from the water treatment can be disposed of in large underground aquifers, avoiding any on-site containment of process-affected water.

Small amounts of produced sand and oily wastes can be transported to approved land fill sites, where natural biodegradation effectively renders the hydrocarbon content benign.

Opportunities to Reduce the In-Situ Footprint
Other than the forest clearing issue, the land disturbance is minimal for both SAGD and the more conventional thermal operations. With the notable exception of forest clearance, returning the sites to their original status does not require special technology.

No further major technology development needs are foreseen for the disposal or handling of small volumes of oily wastes and solids, and the brine from boiler feed water conditioning.

FIGURE 5.6 IN-SITU OPERATIONS INVOLVING LAND, SOLIDS AND WATER

courtesy: EnCana
The vision of expanded bitumen production includes major increases in upgrading. At the same time, an expanded refining industry market will demand improved quality synthetics, as they are under legislated pressure to produce “greener” fuels. Increased upgrading will also allow the industry to expand its product suite to finished transportation fuels and petrochemicals, and other niche products.
Upgrading Today
In approximately 1 million barrels per day of current bitumen production, mined production makes up 65% and In-Situ or thermal production 35%. Essentially all of the 650,000 barrels per day of mined bitumen is upgraded. Suncor and Syncrude convert their bitumen production on-site to a light, sweet synthetic crude oil (SCO), and in the case of Suncor, other sour variants. The quality of bitumen recovered by the Suncor and Syncrude mining extraction operations has levels of water and solids that would make it currently unsuitable for shipping to conventional refineries. The Shell led Albian Sands mining project recovers a cleaner bitumen (with more solids and water removed) and upgrades this off-site in Scotford, Alberta. Products include a synthetic feedstock for the adjacent Scotford refinery, and other synthetic blends for marketing. While much of the synthetic crude is processed in Canadian refineries today, there will be increasingly larger volumes marketed in the northern tier US states as the industry expands output.

Of the 350,000 barrels per day of In-Situ production, some of it is upgraded to a light, sweet synthetic crude in Husky’s Lloydminster, Saskatchewan upgrader. However, the majority is shipped with light diluent to those refineries, primarily in PADD II, that are suitably equipped to handle the high residue bitumen (normally in coking units), or that can use the feedstock to satisfy the seasonal demand for asphalt.

This split between end uses for mining based and In-Situ based bitumen is historical. In-Situ bitumen producers will need to consider further upgrading to synthetic crude in future.

Upgrading is typically viewed in two steps (Figure 6.1). Primary upgrading is largely based on coking, but with special catalytic processes being increasingly used. The ebullated bed process uses hydrogen addition, and solid catalyst in a semi-fluidized reactor, with facilities to allow continual withdrawal of spent catalyst and addition of fresh catalyst. The primary step still leaves significant sulphur and nitrogen compounds in the lighter products, and further secondary treating in large hydrotreaters (with high hydrogen addition) is used to produce a synthetic crude. Hydrogen consumption is typically 1000 standard cubic feet per barrel of SCO today, but will rise considerably to as much as 1800-plus standard cubic feet per barrel for the kind of high quality SCO envisaged for projects such as the one planned by Nexen/OPTI.
UPGRADING IN A DYNAMIC MARKET

Figure 6.2 makes some comparisons between current quality synthetic crude and conventional crudes. Synthetic crude has some distinct advantages; essentially zero residue, and low sulphur and nitrogen. However, severe thermally based primary upgrading (coking) produces a highly aromatic crude, with poor quality distillates - jet and diesel fuel components - and gas oils which must be converted in the refinery to lighter gasoline and distillates. In addition, the remaining sulphur compounds are the most difficult species to remove, making future ultra-low sulphur fuels more of a challenge.

Upgrading costs (capital recovery and operating costs) are about $10-15 per barrel for a ‘green field’ site today, but that number is very dependent on scale of operation and the extent of upgrading. Full upgrading requires large scale for acceptable economics, but that scale can also be influenced by the degree of integration between the bitumen recovery and upgrading. Some view 100,000 or more barrels per day as a minimum economic scale, whereas the Nexen/OPTI project will start at 70,000 barrels per day capacity, using new approaches to upgrading, including integrated residue gasification for hydrogen, SAGD energy and power production.

The major economic driver for upgrading is the so-called ‘light-heavy differential’ - the difference in market value between unprocessed bitumen (with associated diluent) and light crude. This differential has varied widely over the years, reflecting the sometimes ‘soft’ market for the heavy bituminous crudes, and the relatively limited number of buyers.

Another recent trend in the industry is the move to integrate upgrading with existing refineries. The Newgrade upgrader in Regina, Saskatchewan, has supplied the adjacent Co-op refinery for many years, but processes less difficult, conventional heavy crude. Shell Canada is the pioneer for integration between bitumen upgrading and refinery integration, in Scotford, Alberta. PetroCanada had similar plans to link the new McKay River SAGD production with their Edmonton refinery, but are now planning to use Suncor upgrading capacity for similar purposes. These projects will succeed on the basis of close integration between the upgrader and the refinery capabilities, potentially saving costs for broad, quality uplift in central upgraders producing a single quality SCO.

To date, the market has been able to accommodate the balance between the positive and more challenging characteristics for the current production, and the product commands roughly light crude value in the market place. In addition, both major SCO producers are known to be addressing the quality issues to ensure margins are maintained as production grows, and is moved to more quality sensitive markets in the U.S.
Future Development Challenges Impacting Upgrading
Some of the industry issues reviewed in Section 2 impact the future for upgrading, and are summarized in Figure 6.3 and discussed below.

FIGURE 6.3 CHALLENGES TO UPGRADING
> Construction cost control
> Capital and operating costs
> ‘Green fuels’ markets and SCO quality
> Natural gas demand
> Expanded markets & end uses
> Coke & Sulphur production

> The capital cost issue has two distinct elements. The first is control of cost overruns that have been a major concern in recent projects. This issue is tied to external forces, such as the availability of skilled trades, remote locations, and labour productivity. These have been discussed elsewhere in this Roadmap and do not have direct technology implications for the industry, but are being addressed.

> The second cost challenge deals with economic upgrading process selection and integration, and reduced operating costs. The record of reduced costs shown in Figure 2.2 has all been at the bitumen recovery end of the oil sands value chain. The industry needs more cost effective upgrading.

> The limited appeal of the current quality SCO in a highly expanded market base is already recognized, and being addressed by the main SCO producers. High aromaticity of SCO is a common problem for Alberta upgraders, and concerted pre-competitive research in this area would make these efforts more effective. The quality issue also has to be addressed in the context of the current drive to ultra-low sulphur fuels in both Canada and the U.S., and the processes that refiners will need to invest in to achieve that aim. SCO quality demands are likely a moving target over the next decade, and this will influence upgrading decisions.

> Natural gas is used for marginal fuel and hydrogen production in upgraders. As with its use for bitumen recovery, this dependency was born of historically low natural gas prices in Alberta, a situation that has been reversing rapidly. Figure 6.4 is an approximate distribution of natural gas use today in oil sands recovery and upgrading steps. In a “business as usual” scenario, the consumption for upgrading - particularly for hydrogen consumption - is high today, and will rise to provide higher quality SCO tomorrow.
The natural gas figures shown for hydrogen production include a large addition for steam methane reforming (SMR) fuel. Natural gas consumption for upgrading amounts to some $3.50 per barrel of SCO production costs at a $5 per Gig-Joule natural gas price. Cost apart, an unsustainable position on natural gas use is developing, as was discussed in Section 2. The long-term vision for the oil sands industry sees internal (or possibly external) resources being used for energy, hydrogen, and power. Gasification is an existing technology, for example, that might be used to consume the least valuable residue from the bitumen barrel for fuel, power and hydrogen. A SAGD bitumen recovery and upgrader complex may require as much as 20-30% of the recovered bitumen to meet these needs, with 10% for hydrogen alone. The integration of such a process may, however, have a beneficial impact on upgrading process selection, capital and operating costs, because a disproportionate cost of upgrading today is devoted to converting these least valuable residues to feedstocks suitable for upgrading to liquid product.

While external alternatives to natural gas for hydrogen production, such as coal, may also be possible, this option precludes favourable synergies between bitumen residue use and primary upgrading.

As well as energy self sufficiency, the vision to 2030 portrayed in Figure 1.1 anticipates an expanded industry product range, with higher quality SCO, direct upgrading to clean fuels (possibly including synthetic natural gas) and petrochemicals production. The petrochemicals industry in Alberta is threatened by the longer term decline in natural gas by-products, such as ethane, which have maintained the industry since its inception in the 1970s.

Upgraders produce solid products that need to be handled. Chief among them are coke (for upgraders using coking for primary upgrading) and sulphur for all upgraders. The future may increasingly bring a secondary solid product; gypsum from flue gas desulphurization units, where coke or other residues are burned for fuel. Solid product containment or use challenges will vary between projects. They will need to be managed in the most economical and environmentally sustainable way.

**Upgrading Technology Today and Some Key Downstream Refining Implications**

Upgrading cannot be considered in isolation of the downstream refining market. The main process options in bitumen upgrading today are illustrated in Figure 6.1. The technical advantages for Ebullated Bed hydroprocessing include more modest operating temperatures and with the addition of hydrogen, a less aromatic product (Figure 6.5). The process also incorporates significant secondary upgrading, such as sulphur and nitrogen reduction.

In order of project start up dates, Suncor and Syncrude both selected coking (but different versions) as the primary upgrading process of choice. Their expansions planned to 2010-2012 will use the same processes, covering some 1 million barrels of combined upgrading capacity by that time. Husky, with unknown expansion intentions, currently processes about 60,000 barrels per day, using ebullated bed hydroprocessing, followed by coking of the unconverted residue. Cokers produce a very low value coke product, the use or disposal of which has already been reviewed in Section 2.

The Shell-led Scotford upgrader uses ebullated bed hydroprocessing alone for primary upgrading. In their case, unconverted residue is shipped by owners in various synthetic streams for market sales, or transferred to owner refineries.
elsewhere. Depending on the refinery, the residue will either be coked to extract some light products, or blended to produce heavy fuel oil. What happens at the upgrading stage cannot ignore the downstream refineries, and their processes. As noted above, the key issue for current SCO is the poor distillate and gas oil quality (see Figure 6.2). These problems are to some degree exacerbated by coking, where cracking in the absence of hydrogen promotes the formation of unusually high aromatic hydrocarbon species. For Jet and Diesel fuels, this is not easily corrected in the conventional refinery processes. This factor alone can limit the percentage of SCO in the typical refinery diet, particularly in the U.S.

The same high aromaticity affects the gas oil quality. This is sometimes referred to as vacuum gas oil (VGO), as it is drawn from the vacuum column in refineries where SCO is co-processed with conventional crudes. VGO (for which there is virtually no related product market) must be converted to lighter products, such as naphtha (or gasoline blend stocks) and distillates. Two options predominate for this conversion in North American refineries; hydrocracking units (HCU) or fluid catalytic cracking units (FCCU).

Hydrocracking is more common in Canadian refineries, as it provides high quality distillates in a market based on an essentially balanced demand for gasoline and distillates. Hydrocrackers are inherently better able to handle the aromatics. This combination, and zero residue, has helped to keep SCO market values essentially “at par” with light crudes.

Fluid catalytic cracking, a process specifically designed to convert VGOs to gasoline or gasoline pre-cursors, is the favoured VGO conversion unit in U.S. refineries (80% of the total conversion capacity), with their higher gasoline/distillate ratio.
market. FCCUs are also common in Canadian refineries. FCCUs also produce poor quality distillate by-product, in small volumes that have to be blended away, much of it in lower value distillates. The FCCU heat balances and conversion levels to the favoured gasoline are both adversely affected by the poor quality of SCO gas oils. This combination of factors will lead to pressure on the value of SCO in the increasingly important U.S. market.

Recent interest in partial or field upgrading (for viscosity reduction and diluent savings) is also dealt with in this section. There is no commercial application of candidate processes today for this purpose. Many of these processes, such as deasphalting and visbreaking may play a role within the next decade, especially where residue use for hydrogen and energy positively influences primary upgrading process selection. The Nexen/OPTI project is potentially the first upgrader to move away from Coking and Ebullated Bed processes. Many new partial upgrading processes that are still under development are discussed below under “Upgrading Technology Tomorrow”.

**Continuous Improvement Opportunities for Current Upgrading Technology**

Unlike the resource recovery end of the oil sands value chain, where Canadian made solutions need to be developed, upgrading technology has largely been the domain of U.S. and European based refinery process licensors. There have been attempts by Canadian researchers, notably Canmet (a Canadian government R&D organization) and Alberta Research Council (“HC-3” process) to develop processes for primary upgrading. However, the effort has never received the necessary financial or other support to move from demonstration to commercial application.

The oil sands industry by its growing size, is in a position to influence technology development for their relatively unique needs. It is important to identify the possible avenues for better upgrading technology for current and future projects. Figure 6.6 identifies some technology development challenges for existing commercial processes.

**FIGURE 6.6 CONTINUOUS IMPROVEMENT OPPORTUNITIES**

- Coking technology
- Ebullated bed process developments
- Moderate primary upgrading
- Taciuk kiln
- Hydrocracking v. Hydrotreating
- Catalyst Development
- Residue gasification
- Petrochemical Processes

- Delayed and Fluid Coking technology will continue to develop, but largely through the efforts of current licensors. Independent R&D in labs such as the National Centre for Upgrading Technology (NCUT) in Devon, Alberta, will use pilot coking units as support tools to generate feedstocks for R&D into secondary processes and general integration questions, or for industry-confidential development work. However, there is also a growing need to understand how coking performance is influenced by processing bitumen that is recovered by means that include partial upgrading, such as the paraffinic-solvent based process in use by the Albian Sands plant.

- Similar comments apply to the Ebullated Bed process, where two Licensors share the relatively small market base. However, there is still a need for a more fundamental understanding of this process on different feed stocks, such as partially deasphaltered bitumen.
> Currently developed alternative processes for moderate primary upgrading include visbreaking (including aqueous visbreaking) and deasphalting. More recently, the ORMAT process has been proven for inclusion in the Nexen/OPTI joint venture SAGD and Upgrader project. Milder thermal and physical processes, either alone or in combination, may have one of two possible roles; as field upgraders to reduce or eliminate the need for diluent for transport, or as primary processes in future upgraders where some residue is removed and consumed in hydrogen production. The basic process development work will likely continue to be the purview of the licensors, but again, pilot versions have a role to play in independent R&D. There is a need for better understanding of visbreaking or similar moderate thermal process performance, in particular at higher severity than is usually employed by similar processes in refining.

> The Taciuk kiln process is a well developed Canadian invention currently in use for shale oil upgrading in Australia. The process needs prototype scale development on oil sands to be considered by the industry.

> More moderate primary conversion is a better fit for the introduction of hydrocracking as a secondary process to higher value synthetic crudes. In addition, the higher severity and versatility of 2-stage hydrocracking offers more flexibility to alter naphtha/distillate ratio of the final products, perhaps even produce specification distillate “fuels of the future”. Hydrocracking also results in significant improvement in the quality of the gas oil (VGO) as FCCU feedstock. Hydrocracking is a well established process, and its continued development by recognized licensors is to be expected, and can be encouraged by greater interest from the oil sands industry, to address our specific technical challenges. Capital cost and greater hydrogen consumption are known deterrents, but the challenges we have discussed in this section will likely make conventional hydrocracking, suitably tailored, increasingly a process of choice for future upgrading. The higher cost also has to be seen in the light of potential capital and operating cost savings at the primary upgrading stage.

> Catalysis is a key aspect of a number of processing steps to upgrade bitumen and derived materials. In primary upgrading, catalyst development has received significant attention as part of the Canmet, and similar process developments. Ebullating bed catalysts are constantly improved by catalyst vendors such as Criterion and W.R.Grace. In refining, the continued global trend towards processing heavier feed stocks forces catalyst vendors such as Criterion, Chevron and UOP to continuously improve hydrocracking and hydrotreating catalysts. Subject to similar pressures, catalyst vendors such as Engelhard and Akzo, continue working on FCCU catalysts that perform well with heavier feed stocks. However, most of these efforts are global in nature, and only a small fraction of this work directly addresses Canadian oil sands industry concerns, which are primarily concerned with the unusually high aromatics content of bitumen and resulting synthetic crude cuts. There needs to be more catalyst R&D focussed on specific oil sands industry needs.
Partial oxidation-based Gasification is a known process, and has been employed for many years in refineries and elsewhere to consume excess residues. This might also include gasification of by-product coke. Technically, gasification is versatile. It breaks down any hydrocarbon into synthesis gas ("syngas") - a mixture of hydrogen and carbon monoxide - which can then be used directly as a fuel source (not a high value end use) or processed further to hydrogen, and/or synthetic hydrocarbons, including natural gas. One area for cost reduction in gasification is in the supply of oxygen, where the currently used cryogenic air separation process is high in energy and power demand. Because of its connection with alternative hydrogen and energy sources, discussion of the energy "end use", and technology challenges to gasification for the oil sands industry, is deferred to Section 7. Discussion of gasification as a source of synthetic hydrocarbons is discussed in this section under “Upgrading Technology Tomorrow”.

Processes that suit the production of petrochemical feedstocks are well known. Specially adapted fluid catalytic cracking can convert oil sands derived feed stocks to produce light olefins, for example. More industry support is necessary to help advance such developments, as they offer higher value added to the bitumen barrel.

Upgrading Technology Tomorrow
Future upgraders will probably be designed to use a portion of the production for hydrogen and other energy needs. Even projects in advanced stages of development, such as the Syncrude and Suncor expansions, may need to reevaluate their dependence on natural gas for hydrogen as a long-term policy. Using some of the production for hydrogen, ideally the heavier asphaltene-rich residue, also has generally positive implications for the primary upgrading step as well. Some of the technologies that may be part of the longer term future for upgrading are discussed below.

> Certain bitumen recovery processes that are being piloted or recently introduced, both in mining and In-Situ, have the potential to improve produced bitumen quality before further upgrading. In currently known developments, light hydrocarbon solvents are used in processes that are either designed to reduce steam use (In-Situ) or provide a cleaner bitumen in terms of residual water and solids content (mining-based froth treatment). A side benefit - expected, or in some cases proven - is a reduction in asphaltenes content. Such developments need to be assessed for their positive impact on the technology and economics of upgrading. Farther out, recovery processes involving underground partial combustion or gasification will also impact upgrading technology needs.

> The potential for more moderate thermal or other catalyst based primary upgrading processes has been discussed above. Figure 6.8 may not be an exhaustive list.
The processes can be separated into those from licensors with a “track record,” and new processes announced by other developers.

Visbreaking and Deasphalting were already covered above. The ORMAT process has been demonstrated at a large scale for the Nexen/OPTI project. Snamproghetti, HRI and Canmet technologies are not yet fully commercialized, and use a slurry catalyst to assist upgrading. They can be seen as having similar technical objectives to the ebullated bed processes, but at lower severity. The first two are at the stage where a large scale demonstration is needed. The Canmet process, a Canadian development, has been proven at the demonstration stage in PetroCanada’s Montreal refinery for many years. What it lacks is development and marketing by a reputable licensor.

The other processes in Figure 6.8, as far as is known, use variants of thermal pyrolysis. All may include some energy by-product, with the potential to reduce natural gas dependence. Value Creation Inc. (VCI) technology has not been openly published, but is thought to include novel extractive technology as well. From an industry perspective, NCUT can assist in understanding these processes better, and industry will need to help fund demonstration stage units. They will also need to engage reputable Engineering, Procurement and Construction (EPC) companies.

Reverting to discussion of the longer term technology challenges or opportunities in Figure 6.7, hydrogen use in upgrading today is high (around 1000 standard cubic feet per barrel) and will rise for higher quality SCO in future. Targeting the use of this costly commodity, through different secondary processing or new catalysts technology, could help reduce upgrading costs considerably.

Advanced hydroprocessing catalysts probably have the greatest potential for significant future improvements to SCO quality. Nano-engineered catalyst using novel catalytic materials (e.g. Akzo’s Nebula) may offer the potential to improve conversion by an order of magnitude compared to their predecessors. The key to this improvement in all gas oil fractions is to hydrogenate aromatics and open the resulting cycloparaffinic rings. So far ring-opening, except as a consequence of high pressure hydrocracking, has not received consistent attention. This kind of compositional adjustment is a major challenge in SCO quality improvement.

Synthesis gas from (residue) gasification can be converted not only to hydrogen, but also to hydrocarbons with controlled carbon chain size. The process used is one of several commercial variants of Fischer-Tropsch synthesis, which produces long chain paraffins. It is suited to producing high
quality distillates. Figure 6.9 demonstrates the value adding potential from gasification and syngas to hydrogen and Fischer-Tropsch liquids. The figures are very approximate, as residue quality will influence yields. Power and fuel options are discussed in Section 7.

The $8 value for the asphaltite-rich residue feed in Figure 6.9 is notional. It is evident that hydrogen provides the greatest value uplift, and Fischer-Tropsch liquids are less attractive as a standalone option. However, combined hydrogen and liquids might be advantageous in certain future upgrading schemes. In interpreting Figure 6.9 it is cautioned that an accurate uplift value is difficult to determine for Fischer-Tropsch synthesis, and potentially higher value added opportunities, such as petrochemical feedstocks, also need to be assessed. More cost effective Fischer-Tropsch technology is of potential value to the industry.

> Reverting again to Figure 6.7, a drawback in some upgrading is the attempt to co-process all hydrocarbon species at identical conditions, in single reactors. More fundamental research is needed to see if physical or chemical separation processes can be adopted for commercial application, and offer more targeted upgrading steps, and hydrogen addition.

> Biotechnology plays a minor role in the industry today, largely in solids or water cleanup, and not at all in upgrading. There are processes that can be used to remove sulphur components, which might prove of value. However, the emerging nature of this technology requires a much broader mandate for technology surveillance and assessment of potential uses. Application of novel biotechnology to upgrading is likely to be very long-term.
The historical dependence on abundant and inexpensive natural gas, for fuel and the generation of hydrogen, must change. With or without a third development wave beyond 2012, the industry will need to encourage the further development of options to use bitumen based products, or alternatives such as coal. Many of the technologies exist, but need careful attention to costs and operability to ensure wide adoption by the industry.
Energy and Hydrogen Today
A number of the challenges around energy and hydrogen for the oil sands industry have already been discussed in previous sections, because of internal links with recovery and upgrading. The situation today can be summarized this way.

The historical dependence on abundant and inexpensive natural gas for fuel and the generation of hydrogen must change. Figure 7.1 shows natural gas consumption in the key “reserve to synthetic crude” value adding steps.

There are a number of external and internal energy and/or hydrogen sources that need to be assessed to replace natural gas. External alternatives include coal and nuclear, and either can be used for fuel and power. Coal has the added attraction of being an alternative hydrogen source by employing gasification, at economics that are increasingly attractive as natural gas prices rise.

From the bitumen itself, interest is largely focused on the least valuable residue, which is similar to coal in its technical appeal. Residues can be used for energy and hydrogen generation. The added advantage of using internally produced residues is the spin-off benefits from a wider range of primary upgrading technologies that can be employed, as discussed in Section 6.

This section deals with the pros and cons of the alternatives from a technical and economic perspective. Unlike the technology challenges in previous section, energy alternatives deal largely with mature technologies. The challenges have more to do with economics and efficient integration.

Current Costs for Energy and Hydrogen Supply
In the “business as usual” case of natural gas and purchased power, Figure 7.2 provides an estimate of energy costs for all facets of the value added chain, and the added cost of hydrogen (via steam methane reforming of natural gas) under the stated assumptions, with natural gas consumptions from Figure 7.1.

During the timeframe covered by this Technology Roadmap, the declining natural gas production projected in Figure 2.4, combined with the projected “business as usual” consumption for expanded oil sands production, would lead to an unsustainable dependence on natural gas well before 2030, and perhaps as early as 2015.
Not included in Figure 7.2 is the pipeline power consumption, which will add about $0.10 per barrel.

For recovery and full upgrading, and for full reliance on natural gas, costs for energy and hydrogen range from $5 to $8 per barrel.

Several oil sands companies have instituted energy efficiency into their operations in the form of cogeneration systems; the simultaneous production of electricity and thermal energy from a single facility (usually gas turbines with heat recovery steam generators). The electricity is used to meet project energy needs, such as operating mine machinery and in-situ well pumps, with excess electricity being supplied to the provincial grid. It is evident from Figure 7.2 that cogeneration is a better balanced option for mining or upgrading; to generate sufficient steam via cogeneration for In-Situ production will result in a vast excess of power, with limited transmission facilities to handle it at this time.

Based on the Voluntary Challenge and Registry, industry projections are that incremental improvements in technology will further reduce energy consumption and resulting emissions by 2010 by about 20% for the major plants already in operation. This includes the incorporation of gas-based cogeneration.

Some of the alternative energy and hydrogen resources are being investigated under separate technology roadmaps, for example for the coal and fuel cells industries. The needs of all sectors should be coordinated.

The following subsections deal with alternative combinations of feedstock and associated technology for fuel (including power), hydrogen, and fuel/hydrogen combinations. In addition known technology issues for the oil sands industry are discussed. Step-out technology for energy or hydrogen is currently seen as offering only long-term possibilities, but some of these concepts are reviewed.

**Alternative Energy Technologies Today**

The most likely alternative energy options (feed and technology) are listed in Figure 7.3, and are discussed further below.
Coal combustion in advanced boilers, including fluid bed boilers is an option to replace natural gas for energy. There are attendant requirements for stack gas scrubbing, and greenhouse gas emissions increase significantly. The power industry has however been given a significant boost in R&D funding in the U.S. in recent years, by virtue of coal’s dominant position in power generation. Cogeneration of energy and power using coal is therefore a well researched alternative, and there are abundant and relatively inexpensive coal supplies in Alberta. Coal slurry pipelines might offer a cheaper means to transport than rail.

Partial oxidation based Gasification may be used to overcome some of the social barriers to coal combustion, but as will be seen below (Figure 7.5) gasification is currently not as cost effective as simple combustion, where the primary intent is to replace fuel. Also, CO2 emissions are in dilute form, with no advantage over combustion for future sequestration.

Nuclear energy is another possible source of electricity and steam. Canada’s investment in the development of the CANDU nuclear power plant has significantly benefited the country through both the generation of clean electricity and the export of reactors to a number of countries. The possible development of nuclear energy in the oil sands may provide energy security, and improve air quality, as there are negligible CO2 emissions. Nuclear power is a proven technology, with new designs claiming to offer significantly cheaper power with, at the same time, even greater margins of safety in its operation. The nuclear option has been given recent attention in a CERI study9. For a 150,000 barrel per day SAGD operation, advanced nuclear reactor technology appears to be competitive at a natural gas price of $4 per Giga-Joule. However, more work is required on an economically attractive scale, as SAGD operations of greater than 100,000 barrels daily are normally spread out over an area not suitable for steam distribution from a single source. Nuclear energy still has issues around societal acceptance, particularly in terms of the perception of safety risks and the disposal of nuclear wastes.

Internally generated fuels are normally thought of as the least valuable residue portion of the produced bitumen. However, at relatively small-scale SAGD sites, combustion of some of the produced bitumen may be economically more attractive. In larger scale operations, such as an upgrader, the economics likely swing to selective residue use, at the same time taking advantage of the favourable impact on primary upgrading discussed in Section 6. With respect to whole bitumen or residue use, the complete substitution of natural gas for fuel requires about 17% of the production for In-Situ SAGD and 4% for Mining. Cogeneration of power adds to these estimates, but fuel energy needs predominate.

As is the case for coal, gasification for fuel alone is not likely to be cost effective, and
has no advantages, other than the elimination of stack gas scrubbing. Where there is some form of upgrading, either moderate or full conversion to synthetics, *by-product gases and coke* are options for alternative energy. Oil sands companies employing coking have been using some coke to supply part of the energy for the plant, but the solid coke is more costly to handle, and for the most part is stored at the mines.

**Alternative Hydrogen Technologies Today and Continuous Improvement**

Hydrogen generation technology today is possible by three means, summarized in Figure 7.4. In one case – gasification - energy and power are also by-product options. In addition, there are outsourcing (purchase) possibilities.

**Figure 7.4 Hydrogen Technologies Today**

- Steam Methane Reforming (SMR)
- Gasification
- Electrolysis
- Outsourcing Hydrogen

Steam methane reforming (SMR) has been the hydrogen generation process of choice during an era of relatively low cost natural gas. The stoichiometry of the process demands only 0.25 unit volumes of natural gas to produce one unit volume of hydrogen. However, imperfect reactions and added energy needs for the process presently raise the ratio to about 0.4 volume units of natural gas per volume unit of hydrogen. While continued reliance on the use of SMR does not address the need to reduce dependence on natural gas, it will remain a significant process. It shares with partial oxidation-based gasification the ability to chemically extract hydrogen from water (part of the stoichiometry of the process) and produces a more concentrated form of CO₂ for potential future sequestration (Section 8). A number of ideas are emerging to improve reforming operations heat management and reduce energy consumption. These include pressurized fireboxes, helium-heated reformers, electrically heater reformers, molten bath reforming and integrated hydrogen separation reforming.

Partial oxidation-based *gasification* of residues is commercially practiced around the world. Gasification of abundant coal or oil sands residues (perhaps even coke) holds the greatest promise at this time to replace natural gas for this purpose. At the same time, energy and power are natural co-products. Figure 7.5 provides an indication of value added through gasification for energy and hydrogen products, using a typical oil sands residue derived from visbreaking or deasphalting.**
Both power and hydrogen offer higher value added than for fuel. About 10% by weight of the original oil sands production needs to be gasified to produce enough hydrogen to convert the remaining 90% into high quality (40˚ API+) synthetic crude oil. Figure 7.5 does not include capital, but at natural gas prices of about $5 per Giga-Joule, gasification (of fluid residues) is competitive with SMR for hydrogen production (capital included) with both producing hydrogen for around $2.50 per thousand standard cubic feet, or close to three times the cost of SMR or gasification-based hydrogen. The potential cost from a very large-scale nuclear plant, producing fuel and hydrogen via electrolysis has not been investigated.

Several electrolysis methods have been developed and demonstrated for the production of hydrogen. One key consideration is the use of inherently high cost electricity. At $7 per kW-h, the cost of hydrogen via electrolysis is about $6-7 per thousand standard cubic feet, or close to three times the cost of SMR or gasification-based hydrogen. The potential cost from a very large-scale nuclear plant, producing fuel and hydrogen via electrolysis has not been investigated.

Outsourcing for hydrogen does not have technology implications, but deserves to be mentioned here. Refineries produce their own hydrogen by reforming naphtha to produce a high-octane gasoline blending stock. However, refineries are in aggregate short of hydrogen themselves, and will require even more as the need for ultra clean fuels is factored in. In short, refineries will be competitors for hydrogen supply, not net suppliers under typical refinery operations. However, if “refineries of the future” adopt gasification of residues for their own hydrogen supply, they could in future become net suppliers.

A major source of by-product hydrogen is currently available from Alberta’s ethylene crackers. Ignoring for now the logistics of connecting supply to users, the crackers today produce in excess of 300 million...
standard cubic feet of hydrogen, but half of that is already committed to the Shell upgrader and Agrium Chemicals for ammonia production. In summary, outsourcing by-product hydrogen has interesting niche opportunities, but will make a limited contribution to the total oil sands industry need, which is currently at around 600 million standard cubic feet of hydrogen daily, and by 2030 could reach 4-5 billion standard cubic feet of hydrogen daily.

**Future Technology Options for Energy and Hydrogen**
There are new technologies that have been proposed for both energy and hydrogen, but most have major barriers to their development.

> **Hydrogen from Hydrogen Sulphide** is a process concept that has been researched in recent years. On an individual plant basis, the objective would be to regenerate part of the hydrogen lost to sulphur removal, while still recovering the sulphur in elemental form. The scale of this opportunity will vary depending on the primary upgrading steps employed. But if 70% of sulphur in bitumen is removed as hydrogen sulphide, and subjected to a reverse dissociation process to recover hydrogen and sulphur, about 120-150 standard cubic feet of hydrogen would be recovered (at 100% efficiency) per barrel of bitumen, or some 10% of total consumption in future high quality SCO production. The concept could be expanded to include hydrogen sulphide recovered from sour natural gas, using a province wide hydrogen pipeline system to supply upgraders. This concept requires R&D and is long-term in outlook.

> **Hydro-gasification** has been researched. The process uses recycled hydrogen to convert residues, mostly to methane. Followed by calcium oxide reforming with stream, a pure CO$_2$ stream can be produced for potential sequestration. The potential licensors believe this process can be adapted and developed to produce hydrogen within 6-8 years. As with partial-oxidation based gasification, there are other applications (energy and power) of potential interest to the oil sands industry.

> **Electrolysis** was discussed previously, and would need significant R&D to develop higher efficiency, and lower cost to be competitive with Gasification.

> **Thermal Cycles** may offer future promise, to develop hydrogen production from fossil fuel and nuclear power by thermochemical processes. Three types of electrochemical water-splitting processes have been employed: (1) an aqueous alkaline system; (2) a solid polymer electrolyte (SPE); and (3) high temperature (700-1000°C) steam electrolysis. The first two systems are used commercially; the last is under development.

**Inter-Industry Infrastructure and Cooperation**
Apart from technology development in energy and hydrogen, a number of other initiatives are important to raise for the long-term benefit of the oil sands industry as it reduces reliance on natural gas.

To improve energy management for the oil sands, the role of process integration, systems engineering and modeling needs to be emphasized at the plant design phase.
ENERGY AND HYDROGEN

Both recovery and upgrading can be flexible in sources of energy and power. Inter-conversions of these two energy forms, in practice to some extent today via co-generation, represent real opportunities for capturing further energy efficiencies.

The drive for energy and hydrogen self-sufficiency through gasification makes inter-industry synthetic gas and hydrogen trades possible. Centralized hydrogen production with associated distribution infrastructure, already practiced today in the Edmonton-Fort Saskatchewan industrial corridor is one example of inter-industry integration today.

The need for CO₂ pipelining for large scale sequestering is another area for industry wide cooperation, discussed in more detail in section 8.

Optimized use of bitumen fractions, or coal, to replace natural gas for steam, power and hydrogen production will likely be an essential characteristic of the industry during the next 25 years.
8. AIR EMISSIONS

Most non-greenhouse gas emissions are not candidates for effective direct technology solutions, and rely heavily on attempts at abatement. Greenhouse gases, particularly CO$_2$, have commanded the most attention since Canada’s ratification of the Kyoto Protocol. The development vision for oil sands will challenge the industry to seek ways to reduce the emission intensity, and CO$_2$ sequestration by various means is a prime candidate.
This section of the roadmap considers air emission issues, including greenhouse gases. The full complement of air emissions that come from oil sands operations is summarized in Figure 8.1.

FIGURE 8.1 OIL SANDS INDUSTRY AIR EMISSIONS

<table>
<thead>
<tr>
<th>Emissions</th>
<th>North East Alberta</th>
<th>Edmonton &amp; Fort Saskatchewan</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sulphur Dioxide (SO₂)</td>
<td>Upgrader &amp; Sulphur plant stacks</td>
<td>Upgrader &amp; Sulphur plant stacks</td>
</tr>
<tr>
<td>Nitrogen Oxides (NOₓ)</td>
<td>Mining Diesels + Furnace Stacks</td>
<td>Mining Diesels + Furnace Stacks</td>
</tr>
<tr>
<td>Volatile Organic Chemicals (VOCs)</td>
<td>Ponds &amp; Flares Fugitive emissions</td>
<td>Ponds &amp; Flares Fugitive emissions</td>
</tr>
<tr>
<td>Water Vapour</td>
<td>Stacks + Ponds + Cooling Towers</td>
<td>Stacks + Cooling Towers</td>
</tr>
<tr>
<td>Particulates</td>
<td>Stacks, Flares, Vents Reactions from other gases</td>
<td>Stacks, Flares, Vents Reactions from other gases</td>
</tr>
<tr>
<td>Carbon Dioxide (CO₂E incl. N₂O and CH₄)</td>
<td>All fuel sources + Mining settling ponds</td>
<td>All fuel sources</td>
</tr>
</tbody>
</table>

In addition to emissions that may be measured, odours are a general concern, and trace toxics are seldom measured.

Aside from any scientific basis behind emissions, their potential long-term environmental impact, and efforts to reduce them, aesthetic considerations are becoming of great importance to society in highly populated areas. Cooling tower plumes in the Fort Saskatchewan area are a specific example that may need to be managed over time. Flaring is another obvious target for reduction to improve neighbour relations.

Review of the Edmonton and Fort Saskatchewan area indicates that there is enough room for another 750,000 barrel per day of oil sands upgrading capacity (alone or with refining), and this is twice the current refining and upgrading operating in the area today. So the challenges will become greater with time, and will only be met successfully through attention to community relations.

Non-Greenhouse Gas Impacts

The non-greenhouse gas emissions are in many cases not candidates for effective direct technology solutions, and rely heavily on attempts at abatement. The notable exceptions are the first two listed in Figure 8.2.

FIGURE 8.2 NON GREENHOUSE GAS EMISSIONS

> Sulphur Dioxide
> Nitrogen Oxides
> Volatile Organic Chemicals
> Ozone
> Particulates
> Water Vapour
> Flare reduction

> Sulphur dioxide emission come from cokers, sulphur plant tail gas incinerators, and from any energy combustion, including vehicles. While vehicular SO₂ emissions are not a major concern for the oil sands industry, ultra low sulphur fuels being legislated into use by 2007 will reduce emissions from this source in mining operations. Oil sands plants are governed by legislated restrictions. Technologies for abatement largely come down to stack (flue) gas scrubbing. SO₂ is one of the three major contributors to acid rain, along with
nitrogen oxides and ammonia.

- Syncrude is building major new flue gas scrubbers and reacting the SO₂ with ammonia from sour water stripping to produce ammonium sulphate, a fertilizer.

- Nitrogen oxides (NOₓ) - another contributor to acid rain - come partly from furnaces, where the industry is already moving to low-NOₓ burners. Of increasing concern are NOₓ emissions from diesel trucks in the mining sector. Fuel switching is an alternative; running diesels on natural gas will reduce NOₓ by about 40%. Propane may be another alternative. Consideration of systems that directly reduce NOₓ emissions may also be needed. More R&D is required in this area.

- By 2010, Alberta is seeking a 50% reduction in both SO₂ and NOₓ per production unit.

- Volatile organic compounds (VOCs) can be from multiple sources of ‘fugitive’ emissions (valves, gasketted joints, tanks etc.), which can be reduced through active preventative maintenance. Mining ponds are much more of a challenge, where the VOCs are present in the large tailings streams after froth recovery via naphtha or other solvents. More R&D is needed to find better ways to reduce residual solvents in tailings streams.

- Ozone (a contributor to smog) is largely formed by sunlight catalyzed reactions between oxygen and NOₓ and VOCs.

- Particulates are predominantly from diesel exhaust in the mining operations, and from reactions between air and NOₓ and VOCs. Fluid and delayed cokers also contribute particulates. All types of particulate sources are contributors to smog. One target of ultra-low sulphur diesels (with lower boiling end points and higher cetane numbers) is the reduction of particulate emissions.

- Water vapour, which is most visible from stacks and cooling towers, reacts with the chemical agents noted above to form smog and acid rain. The need for more water conservation mentioned in many other sections is pushing the industry to more air cooling, which will have a positive impact on cooling tower plumes. In Northern Alberta the warm settling basins emit high water vapour levels, and the acid rain in that area and Northwest Saskatchewan threatens highly sensitive soils and lakes. In the Edmonton-Fort Saskatchewan corridor, smog is an issue.

- Flare Reduction via capture and recycle of vent gases is proven technology.

**Beyond 2015**

Except for challenges introduced by new process technologies, we expect evolution in all areas of air emissions reduction. In general, total caps on all listed emissions will be lowering over time. The best available technology will usually be applied, and cost is becoming a secondary factor. Major ongoing R&D will be needed to continue reductions of these air pollutants.

**Greenhouse Gases**

Several gaseous emissions are suspected of contributing to climate change. The major greenhouse gases (GHGs) of concern for the oil sands (and, indeed, the conventional oil and gas industry) are carbon dioxide (CO₂), methane (CH₄) and nitrous oxide (N₂O). The latter two have a much greater potential global warming impact on a per unit basis (factored by 23 and 310 respectively) relative to CO₂, but are present in much smaller concentrations. The addition of the three factors is referred to as CO₂ “equivalent,” or CO₂E. CO₂ typically accounts for 85-95% of the total effect. CH₄ is responsible for the majority of the remaining effect.

The U.S. is technically the most active country in CO₂E concerns, and has the highest volume of GHG emissions. Its course of actions, federal and state, will likely impact the international agenda. However, coordinated U.S. efforts may not be agreed on until much later in the decade.
AIR EMISSIONS

All site CO₂, CH₄, and N₂O emissions are considered here, although it is recognized some may not be covered by the Canadian GHG covenants currently in negotiation.

Project-Specific CO₂E Emissions

Before reviewing the projected long-term impact of increased oil sands development on aggregate CO₂ emissions, it is instructive to review a range of project-specific emission intensities, and estimates for this are shown in Figure 8.3.

There are a large number of variables in making such estimates, but it is evident that mining-based recovery alone will be as low as 40 kilograms CO₂E per barrel, and about 60 kilograms CO₂E per barrel for In-Situ, in both cases with natural gas as feed. These are not directly in line with natural gas consumptions in Figure 7.1, as the mining operations also include CO₂E emissions from mining equipment, the tailings ponds and higher power consumption.

Burning residue for SAGD fuel (see case D) will increase CO₂E emissions to around 80 kg per barrel. Similar trends would also apply using residues in mining-based bitumen or selected residues. (Coke is already burned at Suncor and Syncrude, but the impact on CO₂E emissions is reflected in the “upgrader” numbers).

At the high end of the spectrum, combining SAGD using residue as fuel, and upgrading using more residue for hydrogen, will result in as much as 160 kilograms of CO₂E emissions per barrel of SCO.

Aggregate Industry CO₂E Emission Projections

Figure 2.5 (Section 2) projected “business as usual” CO₂E for the conventional oil and gas, and the oil sands industry at the “vision” production levels. The projection for oil sands alone is repeated here in Figure 8.4, using information from Figure 8.3 and a production and upgrading scenario to the year 2030. (see Forewords to this report). The challenges before the industry in CO₂E emissions are clear.
In 2003, NRCan were starting individual company covenant negotiations for the period 2005 through 2012. International negotiations for the period after 2012 have started informally, but there is no consensus on when that will be concluded.

Alberta’s alternative 50% reduction plan per economic unit from a 1990 base is recognized, but again subject to specific company negotiations. This target is less easy to include in Figure 8.3, and the trend line and 2020 target shown are only directionally correct.

The industry has been informed by the Federal government that by 2012, the reported 85% of “business as usual” (BAU) emissions per economic unit of production are without penalty, and that the remaining 15% will be assessed at $15 per tonne of CO₂E, unless the producer is able to secure third party GHG credits at a lower cost. What is not clear is how the Kyoto Protocol will develop after 2012, and this industry, with long development ‘lead times’, needs to know that well in advance to commit development funding.

At the time of preparing this Roadmap, Russia has announced that it will not ratify the Kyoto accord, which is now short of the target for the first phase to proceed, adding another uncertainty.

Assuming some form of CO₂E emission abatement will be implemented, part of the forward thinking needs to take account of the international implications. How will any ‘unproduced’ oil sands barrel be replaced by the U.S. refiners? Figure 8.5 is an assessment of life cycle emissions from competing sources. (Note that the basis here is “kilograms CO₂E per cubic metre”; there are 6.29 barrels in a cubic meter)
AIR EMISSIONS

Firstly, as is well known, 70-85% of life cycle GHG emissions come from the burning of the final fuel products. Secondly, the average world oil barrel is getting heavier; and the most logical “replacement” barrel for U.S. refiners is from Mexico or Venezuela, with essentially the same level of emissions.

The oil sands industry needs to work to do much better than “business as usual.” The 15% or so of total life cycle emissions at the production stage are to a large degree the result of the high energy use for bitumen recovery, reductions for which have been reviewed in previous sections as a major target for overall cost reduction as well. However, the likely drive to internal sources of energy to replace natural gas will still see emissions accelerating, as shown in Figure 8.4.

CO2 Emission Reduction Technology

So how can we improve in the medium to long-term? Are there cost effective solutions that can be developed to render more greenhouse gases benign? Figure 8.6 summarizes two approaches with technology implications to reduce GHG emissions in future. This section will not repeat indirect solutions through production energy reduction, as this has been discussed previously.

CO2 Sequestration is at the top of the list of future solutions. Included in this solution are not only non-productive (benign) storage in depleted oil and gas reservoirs, or in aquifers, but also the use of CO2 for enhanced oil recovery (EOR) or coal bed methane production (CBM), where some value is derived from the CO2. On a somewhat smaller scale, CO2 reinjection for reservoir repressuring may be a solution for the gas-over-bitumen issue.

Sequestering is only feasible today for more concentrated, and easily aggregated sources of CO2. That is not currently the case for energy and power end uses, where the nitrogen from combustion air dilutes the CO2. However, hydrogen production (via steam methane reforming or gasification) does have the capability to produce CO2 in more concentrated form. Referring to natural gas use discussed elsewhere (Figure 7.1) and assuming a 50-50 split between mining and in situ production, with an eventual 80% of production upgraded, it can be estimated that about 30% or more of the CO2 shown in Figure 8.4 might be captured and be made available for sequestration. This alone could be close to 100 Mega-tonnes CO2 annually at 5 million barrels of bitumen production. In figures quoted below, the 100 mega-tonne annual volume is used to compare years of storage capacity.
Estimates of the storage capacity in various geological formations vary, but some published data is available.

The highest cost option is likely benign storage in depleted oil and gas reservoirs. Figure 8.7 is one view of capacity and cost. Using 100 Mega-tonnes as a guide, the largest and most accessible depleted reservoirs would provide storage for around 90 years, but at a high cost of above $75 per tonne. This figure takes into account collection, pipelining via a future network, and injection. Spread over a 2030 production level of 5 million barrels daily, this would cost $4 per barrel, an amount that would have serious consequences for the industry.

Estimates for other sequestration targets exceed the gas and oil pools identified above. EOR and CBM applications, and aquifers have been studied, and all combined storage options are shown in Figure 8.8.

The CBM and EOR applications, and potential gas-over-bitumen uses, will command some netback for the CO₂ delivered.

Deep saline aquifer storage can potentially play a role in sequestration. Proximity, co-injection of other dirty gas streams and geochemical pathways to in-situ mineral fixation may all support this option in future.

In total, there is substantial storage space available - enough for more than 300 years at 100 Mega-tonnes per year. However, much work is needed to bring down the costs. Major R&D is required in all areas of sequestration, which differ in their technical drivers, and there is also a need for serious studies on a suitable CO₂ transportation grid.

Not included in this review is the option of deep water (sea) storage, which is more relevant to coastal or offshore operations.
Reverting to Figure 8.6, breakthroughs in $\text{CO}_2$ chemistry might offer means to convert or use the gas in some kind of captured or neutralized state. However, if such applications are developed, they would need to make a serious dent in a very large $\text{CO}_2$ volume to compete in industry’s minds with sequestration.

Overall, there is a need for ongoing R&D, and field scale demonstrations into $\text{CO}_2$ management, and such work is already the subject of international R&D, often funded as joint industry projects. The issue is an energy industry-wide one, and it is both hoped and expected that solutions will be equally applicable to the oil sands producers.
MANY AREAS OF FUNDAMENTAL SCIENCE HAVE MADE MAJOR CONTRIBUTIONS TO THE OIL SANDS INDUSTRY TODAY. LOOKING FORWARD, NEW SCIENCE HAS THE POTENTIAL TO CONTRIBUTE LONG-TERM BY PROVIDING NEW INSIGHTS, NEW TOOLS FOR ANALYSIS AND DESIGN, AND POTENTIALLY NEW PROCESSES.
Supporting Sciences

Multiphase Computational Fluid Dynamics

The development of computational fluid dynamics, or CFD, has revolutionized the analysis of single-phase flows in applications ranging from aerospace to chemical reactors. Our ability to accurately predict flow and pressure drop in multiphase systems is still in the early stages. As these techniques develop, we will be able to accurately predict flow of fluids through a reservoir using fundamental definitions of the oil, water, vapour and solid phases and their interfacial interactions. In combination with computational chemistry methods, we will be able to analyze emulsion behaviour in production and extraction operations and optimize the design of chemical reactors for upgrading of bitumen.

Nanotechnology

Nanotechnology is the use of unique properties of matter that depend uniquely on its structure at a length scale of 1-1000 nanometers (1-1000 x 10^-9 m). The intense interest in this field has been driven by two enabling technologies: the continued reductions in the dimensions in the components of integrated electronic circuits toward the nanometer range, and new microscopy techniques that allow imaging and manipulation of individual atoms and molecules. The establishment of the National Institute for Nanotechnology in Edmonton will ensure that “nano” becomes an important aid to technology development in Alberta. Nanotechnology will give us new sensors and devices that combine biological and electronic components, nanomachines, and new materials with novel structure. The earliest impact of nanotechnology will likely be new sensors for monitoring and control. Commercialization of new materials based on nanotechnology, such as alloys, polymers and composites will require completely new manufacturing methods. Early breakthroughs are possible, and already being worked on, in the area of improved catalysts. Catalysts for hydrotreating and cracking already constitute a fully commercialized nanotechnology, but the new technologies will give access to new tools and approaches.

Petroleomics

The term petroleomics was coined by Alan Marshall and Richard Rodgers (Florida State University) to describe the search for relationships between chemical composition and properties of petroleum. Based on a new analytical technique that allows the identification of thousands of components of petroleum by their elemental composition, petroleomics seeks to define how the underlying chemical components in a crude oil or bitumen determine its behaviour. Immediate applications include relating the geology and origins of crude oil to its chemical composition. By analogy to genomics, the study of how the human genetic code functions, petroleomics seek to understand not only the molecules present in crude oils, but also how they interact with each other during production and processing.

Computational Chemistry

Advances in computing have supported an explosion in new methods for analyzing how molecules behave. We will eventually have the ability to predict all of the behaviour of a fluid once we have described its chemical components. In the oil sands industry, these tools will allow prediction of a variety of...
properties from first principles, including viscosity of oils in-situ with different diluents, precipitation of asphaltenes, coke formation, surfactant and emulsion behaviour and catalytic reactions. When combined with improvements in the analysis of the composition of bitumen fractions, we will be able to confidently interpret and explore the molecular basis that underlies the observed behaviour of oilsands systems.

**Biotechnology**

Biotechnology is the application of biology to solve practical problems. While the majority of applications to date have been in medicine and agriculture, biotechnology has the potential to contribute to the oil sands in environmental remediation and in processing of bitumen. Over the next decade, advances in environmental biotechnology will offer new approaches to treat wastewater, air and soil to minimize the impact of the oil sands industry. New technology will improve the restoration of mining leases and well sites. Biological catalysts will offer new low-temperature pathways for processing of bitumen products, potentially enabling value-added products that cannot be produced by conventional upgrading processes. Ultimately, biotechnology may allow modification of interfacial properties of bitumen in-situ, to enhance extraction and production.
10. CONCLUSIONS ON TECHNOLOGY AND THE WAY FORWARD

Technology improvement and change has been a major factor in improving the economic viability of oil sands projects over the first 40 years. The Oil Sands Technology Roadmap is a catalyst for a new era of innovation. Industry, governments and R&D providers need to reinforce current R&D planning, and coordinate a wider technology development agenda, to meet the long term vision for oil sands development.
Robust oil prices experienced in recent years have helped sustain and grow the oil sands industry. Growth can continue with acceptable long-term returns on investment, so long as the industry controls capital costs and meets and addresses key issues. Crude oil will continue to be a major primary energy source for the foreseeable future. By virtue of its vast resource, oil sands can provide a bridge between the hydrocarbon era and future energy forms.

Industry, governments and R&D providers need to reinforce current R&D planning, and coordinate a wider technology development agenda, to meet the vision for oil sands development in this Technology Roadmap.

### Technology - One of the Keys

Technology improvement and change has been a large factor in achieving improved economic viability for the oil sands industry over the first 40 years of commercial operation. The Oil Sands Technology Roadmap is a catalyst for a new era of innovation. The destination is a profitable low cost bitumen recovery and upgrading business that is self-sufficient in energy and hydrogen production, with an environmental record that compares with, or exceeds that of the conventional oil industry. For each of the oil sands recovery and process steps, technology based sections of this report highlight opportunities for continuous improvement in the technologies employed today, and step-out advances that require longer lead times to develop to commercial application.

### Building on a Foundation

Cooperative technology development is a key to enhancing the industry’s ability to reduce costs and meet the increasing environmental challenges. This message is not a new one, and it is important to recognize previous work, and the cooperative R&D structures already in place, or developed since the National Task Force On Oil Sands Strategies reports published in 1995. Since those reports were issued there have been a number of positive developments, and a growing network of industry and government led R&D.

Since the mid-1990s, two organizations have emerged that have catalyzed innovation in the upstream oil and gas industry, while encouraging collaboration, information exchange and shared intellectual property rights. They are the Canadian Oil Sands Network for R&D (CONRAD) and the Petroleum Technology Alliance Canada (PTAC). This non-traditional approach to technology development has become an essential component of the Canadian energy science and technology innovation system, and has helped develop major economic and environmental advances in the industry.

CONRAD was formed in 1994, and members include mining and In-Situ producers, research providers, academic institutions, and governments. The network promotes and coordinates collaborative research and development in four principal areas: environment, In-Situ recovery, upgrading, and mining and extraction. Competitive advantage for CONRAD members is achieved through integration of communal intellectual property into individual, unique commercial operations. From its inception the CONRAD platform has been used to launch approximately 200 projects valued at a total of more than $100M.

PTAC, whose mandate is broader than the oil sands industry, has brought forward new technology opportunities in seminars open to industry stakeholders.

Two jointly funded Government labs have taken on key R&D roles, and have grown through additional industry use of their expanding facilities and services. The Devon, Alberta Research Centre houses two R&D organizations; the Alberta Research Council and the CANMET Energy Technology Centre (CETC) At the Devon facility, the National Centre for Upgrading Technology
(NCUT), a joint Canada-Alberta heavy oil upgrading research alliance, has developed facilities to undertake R&D in primary upgrading and secondary upgrading, with added emphasis on refinery acceptance of synthetic crudes. Their work has also grown through industry contract work. The Advanced Separations Technology group (AST) has an expanding role in fundamental studies that are largely focused on bitumen recovery technology. For example, unique research work here, funded by both NRCan and an industry consortium, has underpinned the new froth treatment process recently commercialized by the Albian Sands mine at Muskeg River. AST will soon participate with the University of Alberta in advancing mining tailings R&D.

The previous mandate of the Alberta Oil Sands Technology and Research Authority (AOSTRA) has been expanded under the Alberta Energy Research Institute (AERI). AERI was formed in 2000 to provide leadership for Alberta in funding, coordinating, and the harmonization of energy innovation and technology development and transfer, all as part of a cleaner energy strategy. AERI brought together public and private sector partners from across Canada and beyond to collaborate in creating and implementing energy innovation programs. This collaborative effort, named the Energy Innovation Network (EnergyINet), focuses on taking an integrated approach to innovation in six key areas for Alberta and Canada: oil sands upgrading, clean coal and carbon technology, CO2 management, recovery technology in an environmentally responsible manner, water management and alternate energy.

Alberta Research Council (ARC) and its subsidiary C-FER Technologies, will continue to provide technologies to improve recovery, reduce cost, and minimize environmental impact. ARC works through consortia programs, such as the AERI/ARC Core Industry (AACI) Research Program, and directed contract research and technology development and deployment. Some examples of their recent work include the development of novel In Situ oil recovery technologies, and a new mineable oil sands program in ore processability, characterization, extraction technologies, water management and plant engineering support. Through the Sustainable Energy Futures Centre of Excellence, ARC is developing cost-effective technologies, processes and capabilities for the safe capture of Greenhouse gases from combustion and waste gas streams. ARC is also helping to improve understanding of the linkages between energy systems, such as gasification, and emission capture technologies.

The University of Alberta and the University of Calgary have active collaborative research programs, sponsored and supported by industry and government. The principal researchers are investigating many aspects of the oil sands industry, including fundamentals of In Situ production, upgrading and land reclamation. This research provides the basis for long-term development of new technology, opportunities for reducing costs in current operations, and trained graduates for the oil sands industry. The Alberta universities are well positioned to support the industry in the future, but an ongoing challenge is attracting top faculty members and graduate students to oil sands research.

The National Research Council (NRC) has established significant capabilities in the development of wear resistant bulk materials and overlays at its facilities in Vancouver and Boucherville, Quebec.
CONCLUSIONS ON TECHNOLOGY AND THE WAY FORWARD

Recent Studies
In addition to ongoing R&D, there have been important recent studies that have addressed, in part, long-term oil sands technology development needs. During 2001, AERI developed technology roadmaps for the energy industry in Alberta. These roadmaps followed a prescribed format, and were not at the level of background and detail in this roadmap. Based on information from the AERI technology roadmaps, work of the Clean Hydrocarbon Technology Futures Group, staff workshops held in 2002, and industry consultation, AERI released a draft portfolio in June 2003 of priority research and development areas with the most technological potential for significant benefits.

In another initiative, the Clean Hydrocarbon Technology Futures Group issued a report in February 2003. This included a review of future directions for R&D, with a special section on the oil sands industry.

Putting Action to the Road Map
The Oil Sands Technology Roadmap is a “platform” of technology needs and opportunities, without spelling out the detailed plans to get there. This platform must now drive a review of R&D already underway, and incorporation of that R&D into an expanded plan well into this century, directed to ensuring new technology is developed. A follow up implementation plan, will take most of 2004 to develop, and the results will be published as they become available.

The Roadmap has had broad industry support and input thus far. Industry must also take a lead role in encouraging and funding R&D in areas that will meet not only short term business plans but longer term, higher risk opportunities.

There needs to be a clear leadership to the follow-up planning process, and defined linkages between organizations that already exist. NRCan and AERI will facilitate this work, and act as champions of new oil sands technology development. Industry and collaborative R&D providers need to agree on pre-competitive areas of R&D, plans for the appropriate long-term funding, and development through demonstration pilots to commercial reality. This includes R&D in many environmental areas, which are often not a source of industry competition, and where solutions can be more readily shared.

Many industry participants have their own R&D capability, and will focus their internally funded R&D on specific company needs, but at the same time advance technology available for licensing to others.

The oil sands industry will continue to encourage healthy competition between key process licensors and others in the vendor community, and pose challenges for them, where we anticipate they have the lead development role. That will sometimes include joint venture funding and development.

As the plans unfold, and newer technologies are developed or offer themselves, the Roadmap, and the associated technology development strategy must be reviewed and updated. Technology opportunities and developments require flexible planning and redirection as results emerge.

This industry has risen to, and successfully met such challenges before. We must now engage the participation of the expanding number of stakeholders to achieve, and even exceed the vision before us.
As the oil sands industry grows, a number of societal issues will need to be addressed if we are to maintain the permission to practice. The industry must focus on the “triple bottom line”; create economic, social and environmental gains, while correcting any adverse impact from their activities. Society must be seen as a major stakeholder that contributes to the industry and has a vested interest in continuing success through managed growth.
Challenges are not new to the industry. What is new is the number of external or societal issues now at the forefront of public perception. These must be faced and dealt with in parallel with the internal challenges. As the industry expands, it must focus on the “triple bottom line”.

The term “triple bottom line” recognizes the need to capture the values, issues and processes that companies must address to create economic, social and environmental gains, and minimize any harm resulting from their activities. The key and underlying message is that society, as a whole must be seen as a major stakeholder - one that contributes to the industry and has a vested interest in the continuing success of the industry. It is society as a whole that grants industries continuing permission to practice.

This section outlines these interrelationships and lays out recommendations designed to encourage all stakeholders to include them in their considerations and planning. The major oil sands reserves cover Peace River, Wabasca and Cold Lake, as well as the Athabasca region, so the issues dealt with here are relevant for all the regions. However, the Athabasca area has had the greatest impact on society to date, and has been the principal focus of efforts to coordinate the desires of industry and society.

Major strides have already been made in the Wood Buffalo Region through the Athabasca Regional Issues Working Group (RIWG). The intention has been to define and realize a truly sustainable vision of the development of the oil sands, and the enormous economic benefits.

The future vision for all oil sands developments must include a systemic focus on the long-term development in Northern Alberta, and build on the model already developed for use in other regions of the Province and Canada. Given the current state of society, technology roadmaps should now explicitly include consideration of the interplay among science and technology, the industry under review and the wider society.

**Societal Impacts**
Overall, Albertans and Canadians must feel that they are active and effective stakeholders in future oil sands development. This will require an expanded sense of responsibility on the part of both the industry and governments. To ensure mutual trust and confidence, it will require an integration of the industry’s needs and aspirations, with those of the general public. It will require looking beyond the personal, organizational and cultural silos that currently exist, as well as ensuring that adequate resources, commitment and leadership, particularly from champions, are available. New patterns of institutional cooperation are clearly called for if the following types of issues are to be faced and dealt with efficiently and effectively.

**Workforce Availability**
Oil sands development has always presented a demographic challenge. A large population of diverse people has been required to build and operate the projects as well as the necessary supporting infrastructures. Alberta contains only 10% of Canada’s population, yet it employs 20% of Canada’s trades people. The Petroleum Human Resources Council of Canada, in a recent report, cautioned that managing the supply of qualified human resources is critical to the industry’s ability to sustain itself and grow. This will be particularly so in the years ahead when there will not only be growth in projects, but also workforce attrition through aging. A more integrated and collaborative approach to managing future demographic requirements must be developed, if success is to be sustained.
Therefore, not only is it important to increase the size of the workforce but also representation within the workforce. However, many people who could help bridge the manpower gaps need training to do so. The Aboriginal communities close to the developments are already consulted on new projects and supply much of the workforce. This practice will be a valuable stepping-stone to even greater long-term integration of the industry, governments and surrounding communities.

Environmental Impacts
A sustainable environment is one in which development meets the needs of the present, without compromising the future. Concern is rising in Alberta and Canada about the wise use of limited and non-renewable resources, such as water and natural gas, while still producing economic benefit. The long-term goal should be the development of a “minimum waste, minimum impact” economy and society. A shared 21st Century vision of sustainability must be developed, requiring an exceptional degree of courage and commitment on the part of all stakeholders.

Agreement must also be reached on the nature and implications of economic, environmental and societal considerations, and on definitions of what constitutes prudent use of scarce or non-renewable resources.

Similarly, successful environmental management requires new levels of transparent information flows and adaptive management. Building on innovative processes, such as those used by the Cumulative Environmental Management Association (CEMA) and the Wood Buffalo Environmental Association (WBEA), will promote the kind of collaborative approach to environmental management necessary to support expanded development of the oil sands.

Finally, all of this must be seen within a developmental frame. While the goals are long-term, progress towards them must be measured incrementally. Success today, must not be held hostage to a futuristic ideal.

Quality of Living
While increasing the numbers of workers is essential, so too is the need to attend to the large number of issues that bear on the overall quality of living in Wood Buffalo - issues of security of employment, ample and affordable housing, availability of services, transportation, education, healthcare and recreation. Many of these issues are currently being addressed through the “issues management process” used by the RIWG. There are over 400 people, representing over 40 different stakeholder groups, working on these issues. The stakeholder groups represent the aboriginal community, different levels of government, small business, industry, environmental groups and social groups.

This process certainly can be improved and will, with annual reviews and adjustments. The process could also serve as a model for other areas in Canada.
The Way Forward
The RIWG Issues Management Process is well received, but can do more. A new committee is looking into determining a set of sustainability indicators that will track social changes in the Municipality. This process will enable governments to prioritize resource allocations to evolving work issues and concerns. This committee is chaired by the Regional Municipality of Wood Buffalo, and has representatives from industry and social interest groups. The process includes significant public input.

Nothing less than an industry wide response that is integrated with that of governments is required to ensure all players thrive in a global marketplace. The following recommendations have been suggested during the development of the Roadmap:

> Develop amongst Canadians, an awareness of and desire for 21st century solutions.
> Develop amongst Albertans, a desire to see Wood Buffalo as a “skunk works” - a living laboratory for the creation of a truly 21st Century society and economy.
> Develop a shared vision of such a future and of the role of sustainable development within it.
> Develop an integrated approach to the coming demographic crisis – a “Demographics Central” that is an ongoing, province-wide, sector-spanning initiative that integrates demographics, labour force planning, aboriginal peoples, immigration, learning, health care and organizational transformation.
> Design a “foresight lens” - a new decision-making framework, complete with financial analysis, lifecycle economics, and sustainable metrics that enables decisions to be made in light of the emerging future in regional, provincial, national and global contexts.

> Design and implement a regulatory system that is stringent, supportive and enforced, and one which evolves over time in light of the best available information.
> Streamline the approach to Application and Permitting, to move to “one stop shopping” and reduce the time taken to complete the process.

In conclusion, the future development of the oil sands must be, and be seen to be, a joint venture that includes industry, governments and society assisting in the resolution of issues. Success will require people in these groups to champion this understanding and approach.

It requires leaders with a new mindset, a fresh vision with a commitment and willingness to experiment and learn. New companies coming into the region will benefit from the initiatives by those such as RIWG, CEMA and WBEA, and participate in the various sub-committees. Leaders will help promote and communicate a vision of an expanded partnership between the oil sands industry and society for the new future.

The model built by the oil sands must be communicated to all the stakeholders so that they understand and participate in the work of the existing committees and those to come.
REFERENCES


In various figures, the following sources were cited, including some information from websites.

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Cetane Number: A measure used to describe the combustion characteristics of a diesel fuel. A high Cetane Number indicates a better fuel.

Co-generation: A term used for units that are designed for economic generate both steam energy and power.

Coke: Solid, black hydrocarbon which is left as a residue after the more valuable hydrocarbons have been removed from bitumen by heating the bitumen to high temperatures.

Coking: A process commonly used as the first step in bitumen upgrading. The bitumen is cracked by application of high temperatures.

Condensate: Mixture of extremely light hydrocarbons recoverable from gas reservoirs. Condensate is also referred to as a natural gas liquid, and is used as a diluent to reduce bitumen viscosity for pipeline transportation.

Consolidated Tails: See Engineered Tails.

Conventional Crude Oil: Mixture mainly of pentane and heavier hydrocarbons recoverable at a well from an underground reservoir and liquid at atmospheric pressure and temperature. Unlike bitumen, it flows through a well without stimulation and through a pipeline without processing or dilution. In Canada, conventional crude oil includes light, medium and heavy crude oils, like those produced from the Western Canada Sedimentary Basin. Crude oils containing more than 0.5 percent of sulphur are considered "sour", crudes with less than 0.5 percent are "sweet".

Cracking: Process of breaking down the larger, heavier and more complex hydrocarbon molecules into simpler, lighter molecules.

Deasphalting: A family of processes that use light solvents to selectively reject highly aromatic or 'asphaltenic' fractions.

Diluent: see Condensate.

Dragline: Mining machine that drops a heavy, toothed bucket on a cable from the end of a boom into the oil sand, then drags the bucket through the deposit, scooping up the sand.

Ebullated Bed Process: A residue conversion process that employs hydrogen, and keeps the solid catalyst in a semi-fluid state to allow continual addition and removal without halting the process.
**Engineered Tails:** A terms used to describe a mixture of mature fine tails and coarse tails. Also referred to as ‘Consolidated Tails’.

**Established Recoverable Reserves:** Reserves recoverable under current technology and present and anticipated economic conditions, plus that portion of recoverable reserves that is interpreted to exist, based on geological, geophysical or similar information, with reasonable certainty.

**Extraction:** A process, unique to the oil sands industry, which separates the bitumen from the oil sand using hot water, steam and caustic soda.

**Fines:** Minute particles of solids such as clay or sand.

**Fine Tailings, Mature Fine Tailings:** A gel-like material resulting from the processing of clay fines contained within the oil sands.

**Fiscal Terms:** Royalty and tax terms under which the industry operates.

**Fraction:** Separate, identifiable part of crude oil, the product of refining or distillation.

**Froth Treatment:** The means to recover bitumen from the mixture of water, bitumen and solids “froth” produced in hot water extraction (in mining-based recovery).

**Gasification:** A process to partially oxidize any hydrocarbon, typically heavy residues, to a mixture of hydrogen and carbon monoxide. Can be used to produce hydrogen and various energy by-products.

**Greenhouse Gases:** Gases commonly believed to be connected to climate change and global warming. CO₂ is the most common, but include other light hydrocarbons (such as methane) and nitrous oxide.

**Gypsum:** Gypsum is a by-product of flue gas desulphurization units, and is also partly consumed in mining operations to help consolidate fine tailings.

**Heavy Crude Oil:** Oil with a gravity below 22 degrees API. Heavy crudes must be blended, or mixed, with condensate to be shipped by pipeline.

**Hot Water Extraction:** An extraction process whereby oil sand, hot water, steam and reagents are mixed to extract bitumen at a temperature of about 80°C.

**Hydrocarbons:** Organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products. Hydrocarbons may be liquid, solid or gaseous.

**Hydrocracking:** Refining process for reducing heavy hydrocarbons into lighter fractions, using hydrogen and a catalyst. Can also be used in upgrading of bitumen.

**Hydroprocessing:** An upgrading process for reducing heavy hydrocarbons into lighter fractions through the catalytic addition of hydrogen.

**Hydro-transport:** A slurry process which transports water and oil sands through a pipeline to primary separation vessels located in an extraction plant.

**Hydrotreater:** Unit that removes sulphur and nitrogen from the components of synthetic crude oil by the catalytic addition of hydrogen. A final stage in the upgrading process.

**In Situ:** In situ recovery refers to methods to extract the bitumen component of a deposit without removing the rock matrix from its bed. In situ deposits are buried too deeply to be mined by open pit techniques.

**Injection Well:** In enhanced recovery procedures, a well through which air or steam is injected to create heat and pressure necessary to force the oil to a wellbore.

**Lease:** A legal document with the Province of Alberta giving an operator the right to extract bitumen from the oil sand existing within the specified lease area. The land must be reclaimed and returned to the Crown at the end of operations.

**Light Crude Oil:** Liquid petroleum with a gravity of 28 degrees API or higher. A high quality light crude oil might have a gravity of about 40 degrees API. Upgraded crude oils from the oil sands run around 33-33 degrees API (compared to 32-34 for Light Arab and 37-40 for West Texas Intermediate).

**Medium Crude Oil:** Liquid petroleum with a gravity between 23 and 28 degrees API.

**Middlings:** Mixture of water, clay, sand and bitumen that remains between the bitumen froth at the surface and the sand at the bottom of a primary separation vessel at the end of the extraction stage. Further processing is required to maximize bitumen recovery.
Oil Sands: Bitumen-soaked sand, located in four geographic regions of Alberta: Athabasca, Wabasca, Cold Lake and Peace River. The Athabasca Deposit is the largest, encompassing more than 42,340 square kilometres. Total deposits of bitumen in Alberta are estimated at 1.7 to 2.5 trillion barrels.

Overburden: A layer of sand, gravel, and shale between the surface and the underlying oil sand. Must be removed before oil sands can be mined. Overburden underlies muskeg in many places.

Petroleum: A substance composed of a number of hydrocarbons in various combinations. Its most familiar form is crude oil.

Pilot Plant: Small model plant for testing processes under actual production conditions.

Pool: Natural underground reservoir containing an accumulation of oil and/or natural gas.

Process Gas: Gas produced from the upgrading process which is not distilled as a liquid. Usually burned as a fuel.

Proven Recoverable Reserves: Reserves that have been proven through production or testing to be recoverable with existing technology and under present economic conditions.

Reclamation: Returning disturbed land to a stable, biologically-productive state. Reclaimed property is returned to the Province of Alberta at the end of operations.

Remaining Established Reserves: Initial reserves less cumulative production.

Royalty: The Crown’s share of production or revenue. About three-quarters of Canadian crude oil is produced from lands, including the oil sands, on which the Crown holds mineral rights. The lease or permit between the developer and the Crown sets out the arrangements for sharing the risks and rewards.

Steam Assisted Gravity Drainage (SAGD): An In-Situ production process using two closely spaced horizontal wells, one for steam injection, the other for production of the bitumen/water emulsion.

Steam Methane Reforming: A process commonly used to convert natural gas to hydrogen for upgrading.

Synthetic Crude Oil: A high quality, light, sweet crude oil, manufactured by upgrading bitumen extracted from oil sands. Mixture mainly of pentane and heavier hydrocarbons derived from crude bitumen through the addition of hydrogen or the removal of carbon.

Surface Mining: Operations to recover oil sands by open pit mining, where overburden depth permits.

Tailings Settling Basin: The primary purpose of the tailings settling basin is to serve as a process vessel which allows time for tailings water to clarify, and silt and clay particles to settle, so the water can be reused in extraction. The settling basin also acts as a thickener, preparing mature fine tails for final reclamation.

Thermal Recovery: Any process by which heat energy is used to reduce the viscosity of bitumen in situ to facilitate recovery.

Truck and Shovel Mining: Large electric or hydraulic shovels are used to remove the oil sand and load very large trucks. The trucks haul the oil sand to dump pockets where the oil sand is conveyed or pipelined to the extraction plant. Trucks and shovels are more economical to operate than the bucket wheel reclaimers and draglines they have replaced at oil sands mines.

Unconventional Crude Oil: Crude oil which is not classified as conventional. An example would be bitumen and synthetic crude oil.

Upgraded Crude Oil: See Synthetic Crude Oil.

Upgrading: Conversion of bitumen into a lighter, sweeter, high-quality crude oil either through the removal of carbon (coking) or the addition of hydrogen (hydroconversion).

Viscosity: The ability of a liquid to flow. The lower the viscosity, the more easily the liquid will flow.

Visbreaking: A process designed to reduce residue viscosity by thermal means, but without appreciable coke formation.

Western Canada Sedimentary Basin (WCSB): The major land based sedimentary basin in Canada. The basin extends from British Columbia in the west, eastward through Alberta, Saskatchewan and Manitoba, and include portions of the Northwest and Yukon Territories. The WCSB covers approximately 580,000 square miles.