UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER PURSUANT TO RULE 13a-16 OR 15d-16 OF THE SECURITIES EXCHANGE ACT OF 1934

Month of April, 2003

P.E.
4-1-03

Western Oil Sands Inc.
(Exact name of registrant as specified in its charter)

2400 Ernst & Young Tower,
440 — 2nd Avenue S.W.
Calgary, Alberta, Canada T2P 5E9
(403) 233-1700
(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F [ ] Form 40-F [X]

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1). _X_

Note: Regulation S-T Rule 101(b)(1) only permits the submission in paper of a Form 6-K if submitted solely to provide an attached annual report to security holders.

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7). ____

Note: Regulation S-T Rule 101(b)(7) only permits the submission in paper of a Form 6-K if submitted to furnish a report or other document that the registrant foreign private issuer must furnish and make public under the laws of the jurisdiction in which the registrant is incorporated, domiciled or legally organized (the registrant's "home country"), or under the rules of the home country exchange on which the registrant's securities are traded, as long as the report or other document is not a press release, is not required to be and has not been distributed to the registrant's security holders, and, if discussing a material event, has already been the subject of a Form 6-K submission or other Commission filing on EDGAR.

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes [ ] No [X]

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-______.

Exhibit No.	Description
99.1	2002 Annual Report of Western Oil Sands Inc.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Western Oil Sands Inc.

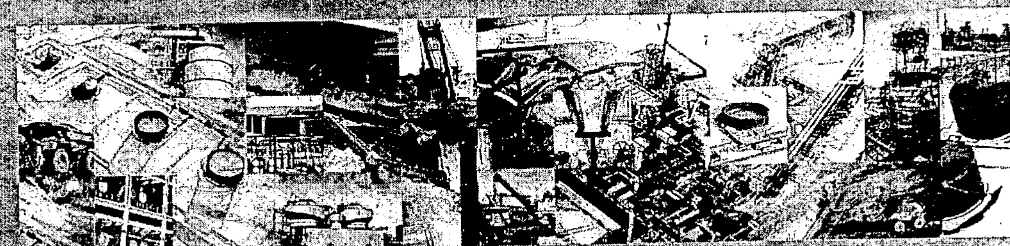
By: ____________________________
Name: David A. Dyck
Title: Vice President, Finance and
Chief Financial Officer

Date: April 10, 2003

EXHIBIT INDEX

Exhibit No.	Description
99.1	2002 Annual Report of Western Oil Sands Inc.

Western Oil Sands Annual Report 2002



Western Oil Sands

2400 Ernst & Young Tower,
440 2 Avenue SW Calgary, AB T2P 5E9

www.westernoilsands.com
TSX: WTO

WESTERN OIL SANDS INC. DEVELOPS OIL SANDS AND RELATED ENERGY RESOURCES, PROVIDING MANAGEMENT, DEVELOPMENT, OPERATING, MARKETING AND FINANCIAL EXPERTISE. THE COMPANY IS A 20 PER CENT PARTNER IN THE ATHABASCA OIL SANDS PROJECT, A MASSIVE UNDERTAKING BEING CONDUCTED WITHIN A JOINT VENTURE COMPRISED OF SHELL CANADA LIMITED (60 PER CENT), CHEVRON CANADA LIMITED (20 PER CENT) AND WESTERN OIL SANDS. THIS PARTNERSHIP BRINGS TOGETHER THE TECHNICAL AND OPERATIONAL EXCELLENCE OF THREE WORLD CLASS COMPANIES TO EXPLOIT AN ENORMOUS RESERVOIR OF OIL SANDS UNDERLYING LEASES IN NORTHEAST ALBERTA, WITH A TOTAL RESERVE POTENTIAL OF 8.8 BILLION BARRELS OF RECOVERABLE BITUMEN RESOURCES. THROUGH ITS INVOLVEMENT, WESTERN ADDS VALUE FOR ITS SHAREHOLDERS AND CREATES FOR ITSELF A COMPETITIVE ADVANTAGE.

During 2002 construction was concluded and commissioning was substantially completed on all processes at both the Muskeg River Mine and at the Scotford Upgrader. 2003 is the pivotal year that our systems will be tested and the efficiency of

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Printed in Canada

AS OF DECEMBER 2002, WESTERN OIL SANDS AND ITS PARTNERS HAD COMPLETED CONSTRUCTION OF THE $5.6 BILLION FIRST PHASE OF THE ATHABASCA OIL SANDS PROJECT (AOSP) WHICH INCLUDES THE CONSTRUCTION OF FACILITIES REQUIRED TO MINE, EXTRACT AND UPGRADE 1.7 BILLION BARRELS OF BITUMEN RESOURCES THAT ARE LOCATED WITHIN THE JOINT VENTURE'S LEASES. THESE RESERVES ARE SUFFICIENT FOR 30 YEARS OF NON-DECLINING BITUMEN PRODUCTION AT 155,000 BARRELS PER DAY. WESTERN EXPECTS TO PARTICIPATE IN PROJECT EXPANSIONS WHICH ARE NOW IN THE PLANNING AND REGULATORY APPROVAL STAGES. IN DUE COURSE, THE JOINT VENTURE EXPECTS TO DEVELOP ALL OF THE REMAINING 7.1 BILLION BARRELS OF RESOURCES UNDER THEIR CONTROL.

our processes proven.

Chairman's Message to Shareholders

THE BOARD OF DIRECTORS OF WESTERN OIL SANDS IS RESPONSIBLE TO AND REPRESENTS THE INTERESTS OF THE SHAREHOLDERS OF WESTERN, A COMPANY WHICH IS DEVELOPING A MAJOR, COMPLEX ENERGY PROJECT IN NORTHERN ALBERTA.

During 2002, the Board dealt primarily with four tasks:

1) To ensure the current, first stage of the Project was executed properly;
2) To plan for and foster development of the future stages of the Project which will ultimately allow production to more than triple to over 500,000 barrels per day;
3) To ensure that the Company was properly financed; and
4) To ensure that the corporate governance of the Company was of the highest standards.

The Chief Executive's report and the remainder of this Annual Report deal with the first three items. There have been significant challenges and we are pleased that the owners' interests in these areas have been actively protected and enhanced.

I would like to speak more directly with regard to corporate governance. In February of 2002, the Board separated the roles of the Chairman and the Chief Executive and clearly identified the Chairman as being directly responsible for the stewardship of the Board. We are pleased with our progress to date. All of the directors, other than the Chief Executive, are independent and most have a significant ownership position in the Company. The Board and the various committees have met frequently during the year and have provided active and constructive direction and guidance for the benefit of our shareholders.

Western's Board strives for excellence in corporate governance. Every Board meeting has a session consisting only of independent directors. There are no loans to management; options have never been re-priced; management compensation is fair and not excessive; and new directors are chosen by the independent directors. The Board truly is responsible for the Company and for representing the interests of the owners.

Western is a company with strong management who think like owners. And with an exceptional resource base, fine partners and dedicated managers and staff, we are positioned to produce excellent results. In our first two years as a public company, the market price of Western's stock has risen over 60 per cent. And this occurred against the backdrop of a major downward movement for North American equity markets.

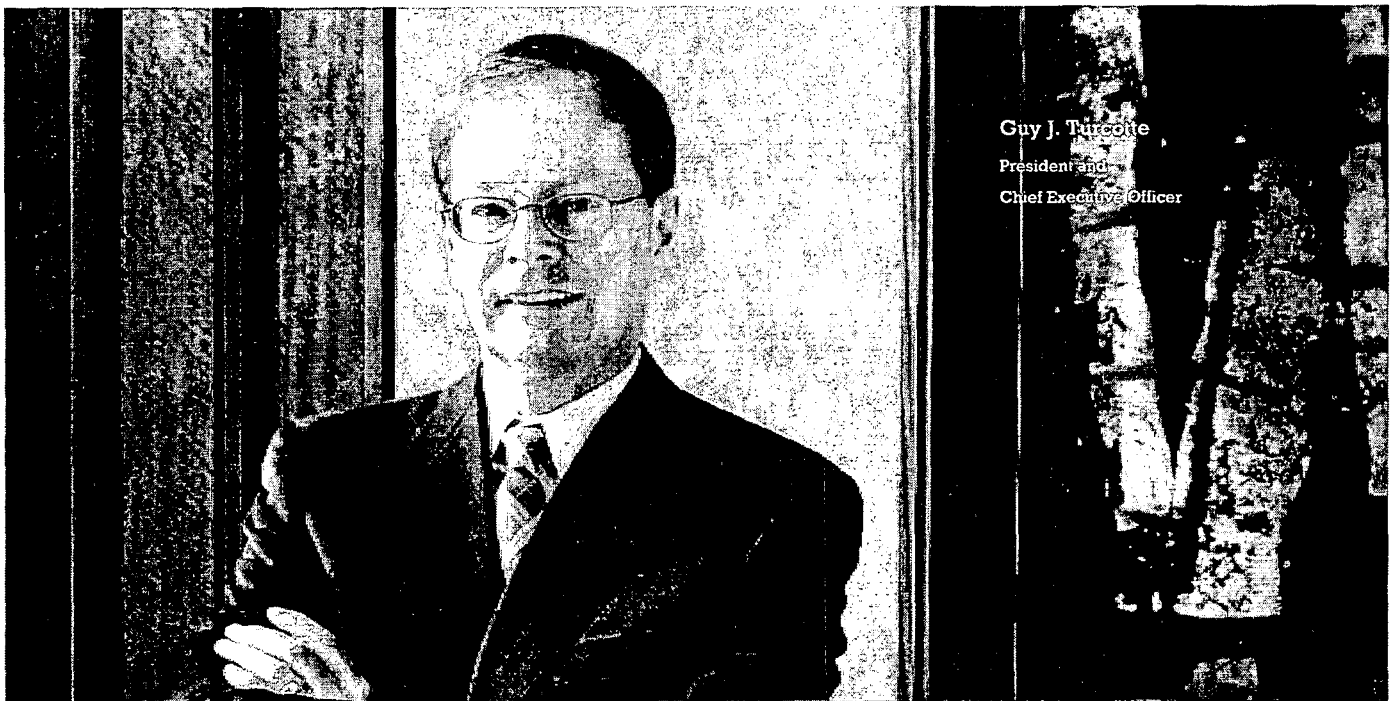
Not everything has gone perfectly but the Western Board, management and staff have worked hard to build a world-class, long-life energy mega-project and to do so in a way that everyone – the local community, staff, owners and ultimately users of energy – can be proud of.

I would like to sincerely thank my fellow directors for their commitment and advice. The entire Board would like to extend to the management and staff of Western our heartfelt thanks for your effort and dedication.

All of us look forward to the realisation of the full promise of this Company.

On behalf of the Board of Directors

Geoffrey A. Cumming
Chairman
March 24, 2003



Guy J. Turcotte
President and
Chief Executive Officer

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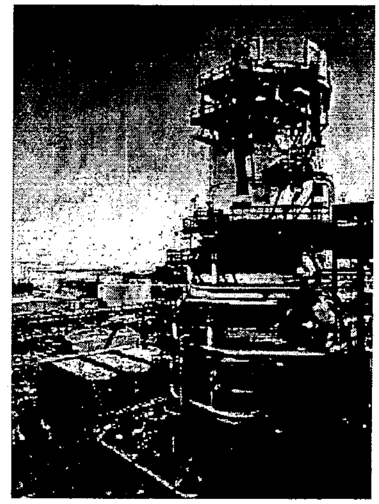
The Joint Venture partners –
Shell Canada, ChevronTexaco
and Western Oil Sands –
have come together in a
partnership that has a

Message to Shareholders



The 2002 year was a watershed year for Western Oil Sands. Over the 12-month period we marched steadily, inexorably towards our project completion target. And we made it. By year-end, the construction force was gone and we were mining oil sands, extracting bitumen, filling the pipelines, and shipping to the Upgrader. In a two-week period we were able to test our systems, quality check our processes and are very positive about the outcome. Clearly there are still corrective actions and start-up problems to work through. But we feel confident today that we will fulfill our mandate, of mining and sending 155,000 barrels per day of bitumen down the Corridor Pipeline to the Scotford Upgrader by the end of the third quarter of 2003.

long-term perspective.

As I look back on 2002, however, there are many more accomplishments of the Western team and its partners. First was our outstanding safety and environmental record. There were millions of man-hours of work invested in the construction of the Muskeg River Mine facilities and Scotford Upgrader over a three-year period. The majority of these man-hours were concentrated in 2002 as we intensified the construction effort to meet the deadlines. In this heightened construction state there were very few incidents, lost time injuries or environmental issues, which allows us to claim truly world-class safety and environmental performance. This impeccable record is, I believe, very rare in the global context of major construction projects. It points directly to the expertise of our people and their leadership in putting such a high priority on safety and environmental concerns.

The number of man-hours also tells a story of the enormous size of this project. In Alberta, we may become somewhat jaded at the description of a multi-billion dollar oil sands project, because we have several of them. In the context of Canada, this project was one of the largest construction projects in the country; in fact likely among the top ten projects in terms of size and complexity in the world. The impact of these projects is considerable. We created thousands of jobs for which Albertans and First Nation communities were preferentially selected for employment. We paid close to $1 billion to the federal government and roughly $300 million to the provincial government in personal income taxes. And these were the direct costs; the economic multiplier effect of our total capital investment in terms of salaries and spending in the economy is likely two to three times those numbers. I believe it is important to keep these numbers in mind when considering the implications of government policies, such as the proposed Kyoto Protocol, which depending on the nature of government guidelines for implementation, could serve to inhibit the viability of projects such as ours.

The total cost of this project is $5.6 billion, which represents an increase of 59 per cent over the original budget. The spectre of cost increases became apparent in 2001 as a result of labour shortages resulting from competing demand from other mega projects in the Fort McMurray area. Costs continued to rise in 2002 as a result of challenges to the expected levels of labour productivity. Western's 20 per cent share of the total cost is $1.12 billion. Forming part of our financing structure is a cost overrun insurance policy in the amount of $200 million that was put in place to insulate us from the possibility of construction costs exceeding the budget that was established for the Project. This amount has yet to be collected from our insurers and is being vigorously pursued.

A major accomplishment of our financial group was the expedient financing program they maintained through the construction phase, which allowed us to stay ahead of the curve in terms of our cash requirements. One of Western's key objectives from the outset was to establish an optimal financial structure; one that gave us access to capital as required but preserved the ability to provide maximum returns to our shareholders. For that reason, our financing strategy was to secure a minimum of equity financing and to pace our debt financings to meet Project capital requirements, with the objective of achieving strong terms that minimized our cost of capital and allows us to ultimately achieve investment grade debt ratings. Thanks to our small but skilled team, we have been able to accomplish these goals. In 2002, we placed US$450 million in 10-year bonds, which will allow the company to employ its cash flow to fund the debottlenecking and expansion phases of the Project.

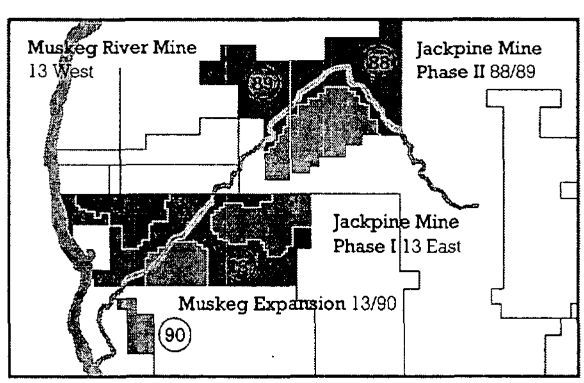
We completed an equity offering in February 2003 for $50.2 million. This financing was required as a result of significant delays in negotiations with our insurers on the collection of the $200 million insurance claim associated with the cost overrun. Western has submitted claims totalling more than $400 million associated with cost overruns and $70 million with respect to delays in start-up of operations. The total of these claims is well in excess of the policy limit designated in our insurance policy. We are frustrated that this process is taking so long, and intend on diligently pursuing full recovery of this claim.

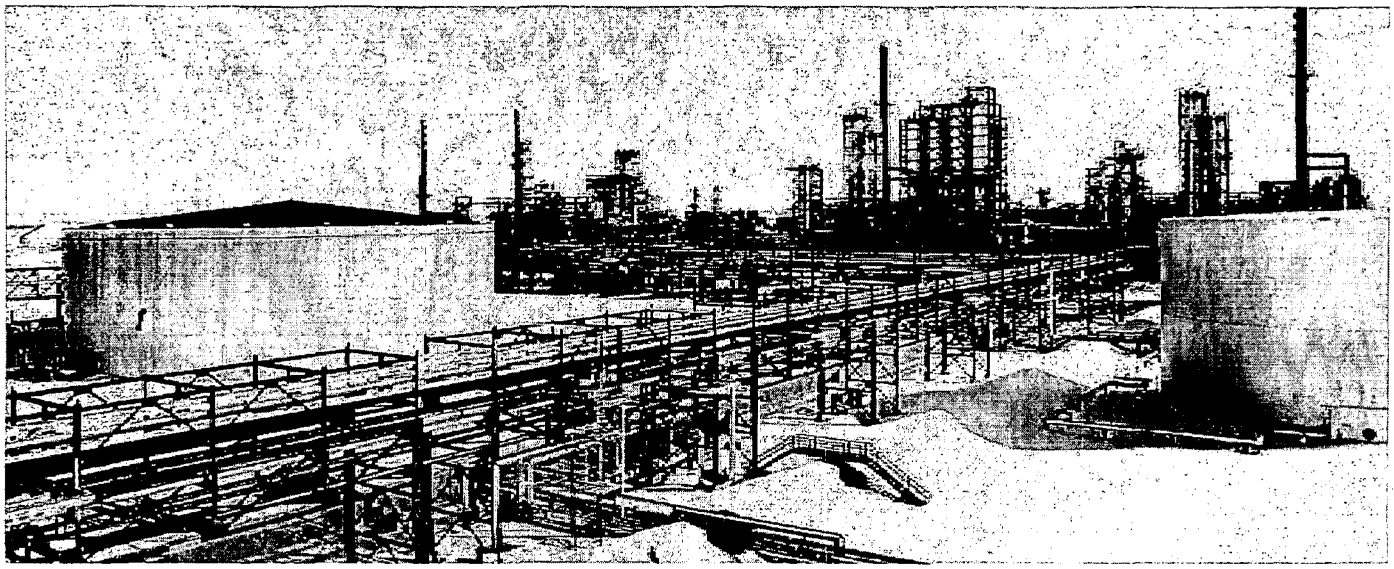
With 2002 behind us, we are facing 2003 with a sense of anticipation and excitement. It will be a pivotal year for Western Oil Sands and the Joint Venture, as we test the reliability of the extraction and upgrading processes and ramp up to full production by the third quarter of the year. As previously reported, the fire we experienced in January was a very unfortunate incident that happily did not injure our people, and had limited impact on the facility. We expect that repairs to the extraction plant will be completed allowing the Mine to be ready to supply bitumen to the Upgrader in preparation of first synthetic oil production by the end of the first quarter of 2003.

For Western, 2003 will be a year of transition as we move from a company focused on construction and financing to one that is managing the operations of the Mine and extraction facilities, monitoring the overall project operations, and marketing our portion of the synthetic crude production. We have established a marketing department, with a team of people skilled in marketing and moving crude oil into the North American and international marketplace.

Our focus in 2003 will also be aimed at the next phase of growth for the company. Once we have reached full production, the Joint Venture will enter a debottlenecking phase of our existing operations. At the same time, we are working on the expansion of the Muskeg River project. This program anticipates expanding our mining capability to reserves that lie beyond the existing permitted section of Lease 13, and south to Lease 90. The expansion project is planned to increase production to approximately 225,000 barrels per day and is scheduled for 2006-2007. We are also in the advanced stages of regulatory approval for a new project at the Jackpine Mine site. This is a two-phase project that will exploit reserves on Leases 13 East, 88 and 89. The application for approval has been submitted and we expect to receive regulatory approval to proceed to the next stage by the fourth quarter of 2003. Construction of the Jackpine facilities is roughly expected to begin in the 2007-2009 time period. These projects are expected to bring total production for the Joint Venture to 525,000 barrels per day within the next 10 years.

project expansions





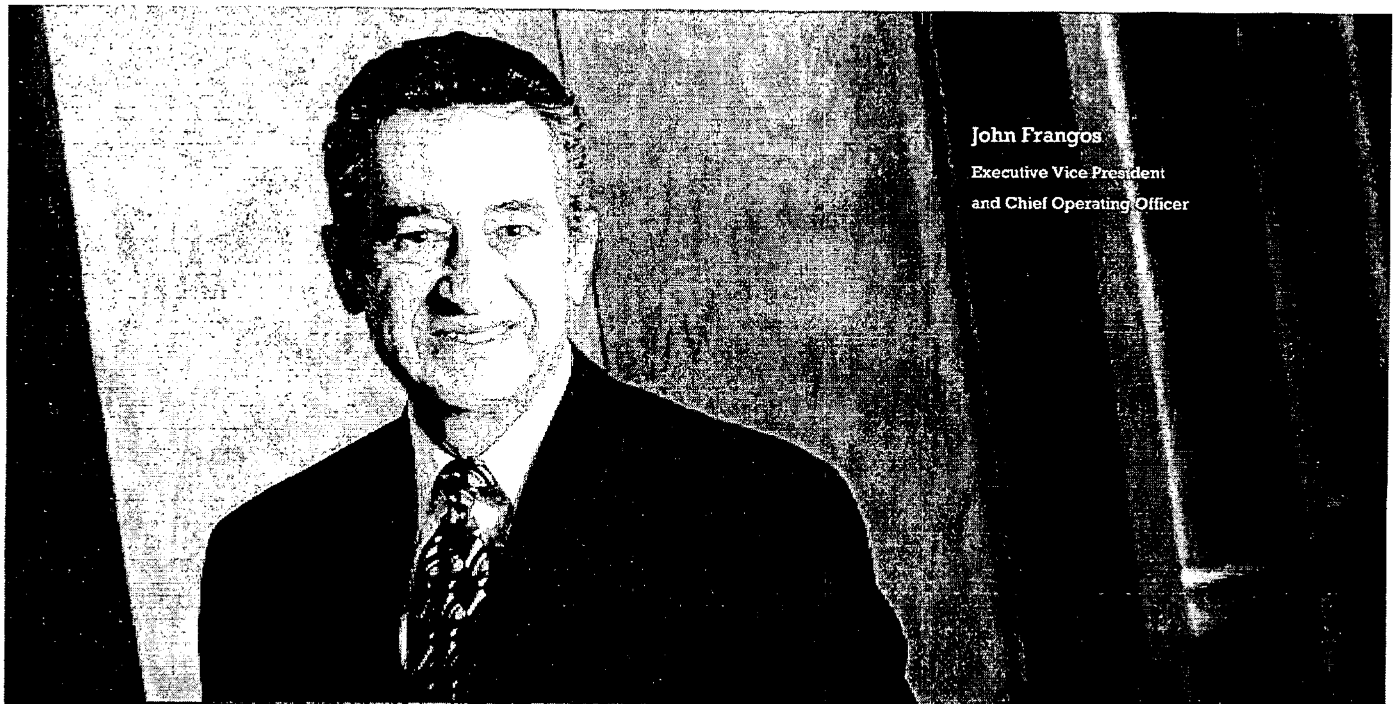
The lead-time required to develop these projects is very long, and the life of the resource base we have to work with is commensurately long. The Muskeg River project is accessing reserves estimated at 1.68 billion barrels of synthetic crude of which Western's share is 336 million barrels. The expansion projects including Jackpine will add 7.1 billion barrels to the total reserve base, bringing Western's total reserves to 1.76 billion barrels. Given these very long lead times, our ability as a company and as a Joint Venture to finance future projects is highly dependent on having a predictable economic and taxation environment within which we can model costs and build investment parameters with confidence. For that reason the implications of the Kyoto Protocol including the methodology of its implementation are critical to us. We are working today without detailed guidelines from the Government of Canada and require clarification in order to move forward confidently. Indications to date are that the implications on Western and its partners are both predictable and manageable. From the outset, Western and its partners were acutely aware of the pristine qualities of the environment in which our project was based and the extreme importance of minimizing our impact on that environment. The mining plan for leases 13, 88, 89 and 90 includes a detailed reclamation and reforestation plan that anticipates areas will be reclaimed on an ongoing basis as the Mine expands. Our plan for greenhouse gas emission reductions was presented as part of our original investor presentations in 1999. As it stands today, the project will be starting up with emissions that are 27 per cent lower than the original case that was approved by the AEUB. We have achieved this through the addition of cogeneration units, the use of waste hydrogen from a neighbouring facility and a variety of process improvements. Our goal is to further reduce emissions by another 50 per cent by 2010 through a combination of energy efficiency projects.

As we move forward into expansion projects, we are critically aware of the value of the learnings we have experienced in this first construction project. This enormous project was carried off with an impeccable safety and environmental record; the pre-commissioning phase was smooth as the construction team handed over the project to the operations group and start-up began. Hours and hours of work went into making sure this would happen, but we also recognize that this knowledge needs to be captured, and lessons learned about where we can improve on this record. We hope to take advantage of the knowledge gained for the benefit of subsequent projects, with the primary objective of successfully delivering the expansion projects.

Three years ago, Western Oil Sands was in its embryonic development phase. Today we are an organization with a market capitalization of $1.2 billion, part of a Joint Venture with world-class partners operating a $5.6 billion project and will be producing and selling 190,000 barrels per day of synthetic crude oil into the North American and international marketplace. Given our light speed growth, it isn't surprising that we are not yet well known, to investors, to refiners, to people in our communities. Our communication focus over the coming years will be directed at broadening the exposure to and understanding of our company. We believe companies today are known, not simply for the investment value they create, but more importantly for the human values they bring to the people and communities in which they operate. For Western as an organization, it is very important that we be known as responsible; a company that respects the environment, the safety of its work force, cares about how it treats people and learns from past experiences. We want to be seen as a valued, responsible contributor to our Joint Venture, and a secure source of high quality synthetic crude to our customers. And we also want to be seen as financially prudent and focused on creating strong, stable and predictable value for shareholders. These are the values of our management team, our employees, and our organization.

There have been many people who made significant contributions to this project and I want to sincerely thank them for their efforts – our employees, our advisors, our Board of Directors, our partners, and you, our shareholders. We are transitioning from construction to operations and production and I believe we have established a very strong foundation for Western in three short and very busy years. I look forward to the challenge and opportunity of guiding Western as it grows and thrives in the future.

Guy J. Turcotte
President and Chief Executive Officer
March 24, 2003



John Frangos
Executive Vice President
and Chief Operating Officer

"The entire process and each individual component of this massive, complex project has been thoroughly tested and we are delighted with the results; confident that we made the right decisions in selecting the best technology. We are now at the pivotal point of driving towards

Operations

Western Oil Sands is ready. After three years of construction and an intense period of testing, we are ready for production to flow and full operations to commence. The 2002 year was a period of focused construction to meet deadlines along with concurrent pre-commissioning, commissioning and start-up. Through this transition, we tested all aspects of Mine and Upgrader operations to our complete satisfaction. Initial bitumen recovery and quality achieved design targets and met all required upgrading specifications. Deliveries of diluted bitumen into the Corridor Pipeline system commenced before year-end, enroute to the Scotford Upgrader. At the Upgrader, the primary distillation units were successfully tested during the fourth quarter and commissioning and testing of the synthetic crude units was well underway at year-end and prior to the end of the first quarter of 2003 we produced our first synthetic crude oil. 2003 will be the pivotal year for us as we ramp up production levels to design capacity. The final push to full-scale production is now underway. The Mine and extraction plant are expected to be operating at design capacity of 155,000 barrels per day of bitumen coincident with full-scale production of synthetic crude oil from the Upgrader by the third quarter of 2003.

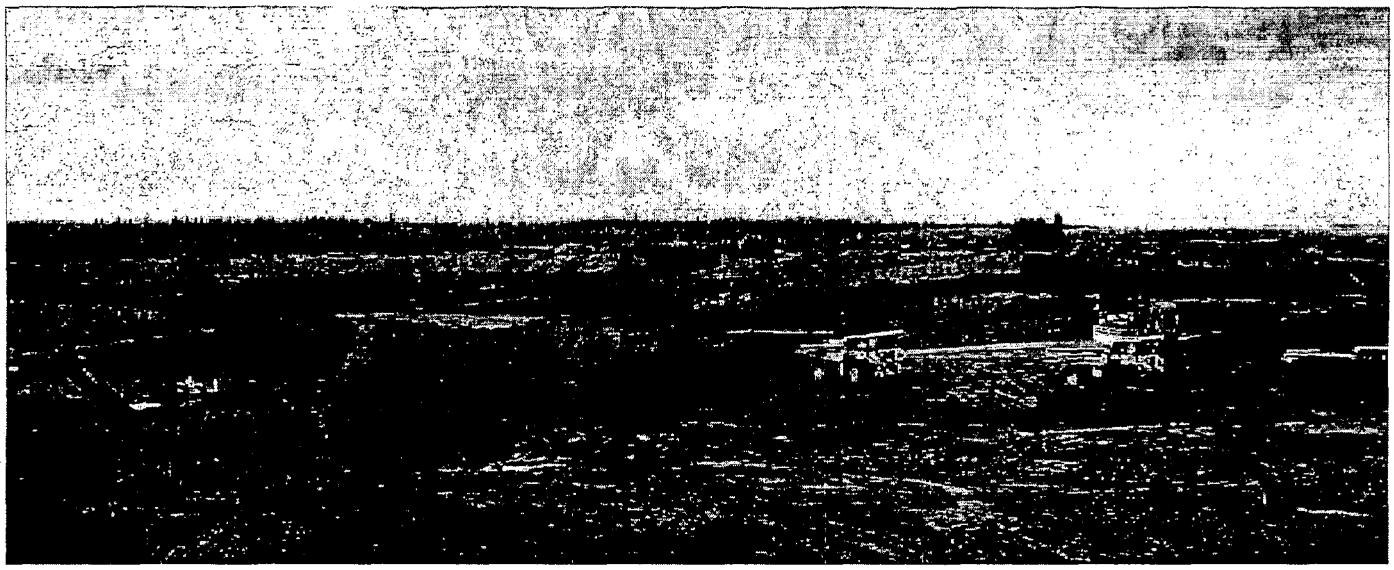
full-scale production.

We look back over the past three years with a great deal of satisfaction over what has been accomplished. We know today that the technology decisions were good decisions; the significance of this cannot be underestimated. Selecting appropriate technology for a project of this size and complexity has enormous implications on the timing of completion and ultimately on operating costs. I believe we made specific choices that will have significant benefits for the operation of the project over the long term. For example, the close coupling of the hydro-treater and hydro-converter at the Upgrader in order to streamline the primary processing units (PPU) flow sheet is a first for the industry and is an unqualified success. There were several other technological "firsts" that I believe we can celebrate. The counter-current decantation circuit at the Mine site – which ensures an ultra-clean bitumen free of impurities for upgrading to synthetic crude in the PPU – is a 500 to 1 scale-up from the Joint Venture's pilot plant and is performing as designed as the technical fundamentals have now been proven in full scale operation. These are but two of the many design improvements we have implemented in this Project that further advances the cost reduction efforts of this industry, so successfully pioneered by Suncor and Syncrude for many years. I believe we owe much of this success to the technology sharing agreements with Syncrude, Suncor, LC Fining and Shell Global Solutions, to name a few. Many other decisions were made with costs savings in mind, such as the sharing of services and facilities with Shell's Scotford Refinery, which helped reduce capital costs and minimize construction cost exposure. These decisions have been implemented and are successfully serving the needs of the Upgrader as planned.

We can also look back on the construction phase with pride for the records set and targets met in the face of extreme challenges. Alberta experienced an unprecedented demand for labour over the past two years and yet these pressures, although costly, had limited impact on the schedule. Scope changes can be significant for a project of this size and complexity, yet we experienced few changes from our original plans which is the result of the discipline applied during the engineering phase of the Project. Noteworthy is the success of our procurement program where early and skillful procurement resulted in major equipment purchases, essentially on budget.

A significant achievement was the world-class safety record achieved by the entire Project. At the peak of construction, over 15,000 staff and contractors were at work on the Project. Yet lost-time incidents were maintained at a level well below both the rate for Canada's industry average, and the average

Steve Reynish
President and Chief
Operating Officer
Albian Sands Energy Inc.



for the oil and gas industry. In 2002 alone, over 30 million man-hours were dedicated to the Project, and the Joint Venture's employees and contractors achieved or exceeded world-class targets. Several provincial safety records were established as we celebrated construction hours without a lost time accident many times at the multi-million manhour level; the highest being over 12 million hours worked.

Throughout the construction phase, we maintained strong and successful relations with our workforce, with no strikes or disruptions, notwithstanding peak manpower of over 15,000 people. This underscores the strong support and cooperation from the province's unions; all 27 unions negotiated contracts in good faith in 2000, leading to a work place agreement mid-year 2000 that was honoured through to construction completion at year end 2002. The leadership of each of these unions, with the strong, continuous, active participation of the leadership at the Alberta Building Trades deserve our gratitude for their unyielding commitment to the success of this Project.

We also owe a vote of thanks to our third party partners who operate several key facilities for the Project. In planning the Project, we identified an opportunity to partner with companies who were experts in the construction and operation of liquid and gas pipelines and cogeneration facilities. On Project completion we can now conclude this to be a wise decision as we move to the operating phase and are now benefiting from facilities that have been construction successes and are operating according to expectations.

The final construction phase in 2002 required tremendous discipline and cooperation from the construction work force and operations personnel, who worked in parallel to systematically hand over components of the Project from construction to operations upon completion to allow for the pre-commissioning of each of these components at the earliest possible time. This cooperative effort was critical to achieving the Project's milestones, and helped increase operational preparedness.

While facilities were being completed during 2002, operational teams were being assembled throughout the year and trained systematically in preparation for start-up using a variety of training tools including plant simulators at both the Mine and Upgrader sites. We cannot understate the experience and skill of our start-up teams at successfully bringing each of the highly complex components of this project through commissioning and into the operating phase. This process has been an intense effort involving highly trained operations personnel as well as specialists recruited from our partners in their other operations around the world. Critical support functions were also introduced at the Mine and

Upgrader sites. These included maintenance capabilities, purchasing and warehousing management, health, safety, security and environmental management; and support functions such as accounting, finance and human resources. With all of these systems in place, we are well positioned to complete the transition to full-scale operations.

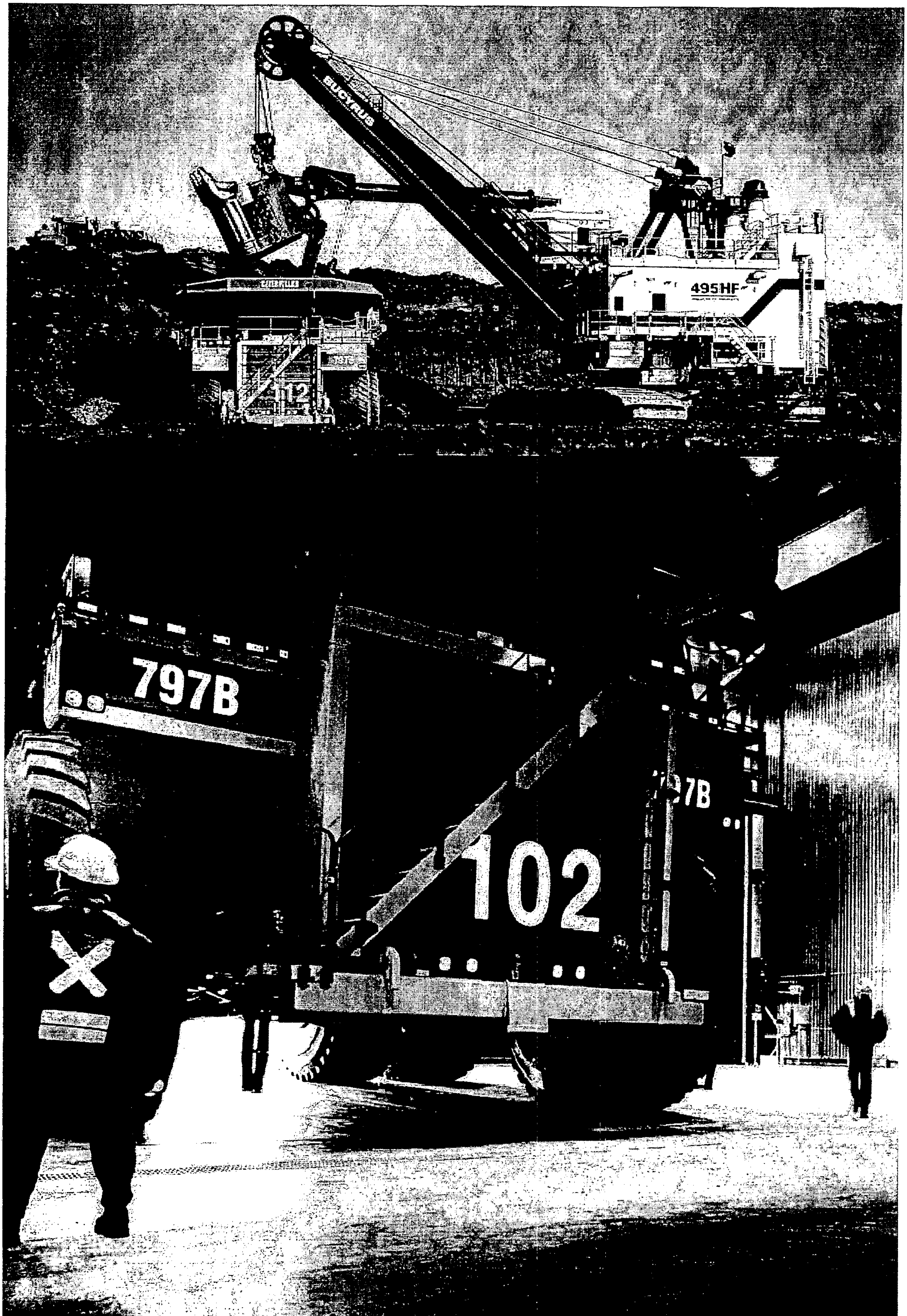
In January 2003, we experienced a fire at the Muskeg River Mine extraction plant that was caused by a leak in the hydrocarbon circuit arising from the failure of a piping connection. There were no injuries and the fire was quickly extinguished. We expect that our insurance policies will cover the cost of repairs as well as any resulting delays to the start-up schedule. After giving effect to insurance coverage provided under our Joint Venture construction policies, this incident is not expected to have a material impact to the Project in terms of costs or delays.

Once full production is achieved, our focus will turn to opportunities to increase production through debottlenecking and expansion. Beginning in late 2003, the entire system will undergo a program of debottlenecking to pinpoint systems and components with underutilized capacity and to investigate ways to optimize performance. This is a process that could take several years and will have a positive incremental impact on production volumes and operating efficiencies. As a further value addition, evaluation is underway to determine the feasibility of adding technology enhancements to the Scotford Upgrader to process heavier carbons which are not converted in the current upgrading process in order to fully optimize the value of the output streams from the Upgrader.

We also look forward to expansion opportunities that will capture the value of the resources underlying our leases. Plans for the expansion of the Muskeg River project are now underway; this expansion will access oil sands resources beyond the existing site on Lease 13 and south to Lease 90. This expansion project is scheduled for 2006-2007. Upon completion of the debottlenecking and expansion, production is expected to significantly increase by 50 per cent to approximately 225,000 barrels per day.

We are also in the advanced regulatory approval stage for a new project at the Jackpine Mine site. This two-phase project will exploit reserves on Leases 13 East, 88 and 89. We expect to receive approval to proceed to the next stage by the third quarter of 2003. Construction of the initial Jackpine facilities is roughly expected to occur in 2007-2009. These projects are expected to bring total production for the Joint Venture to 525,000 barrels per day within the next 10 years.

As we enter the pivotal year of commencing operations, we are entering a new phase as a revenue-generating entity. Our expertise in mining and extraction combined with the proven ability to fund such a massive project, are now matched by a substantial base of knowledge to leverage into further projects to capitalize on the huge resources of the Joint Venture's oil sands leases.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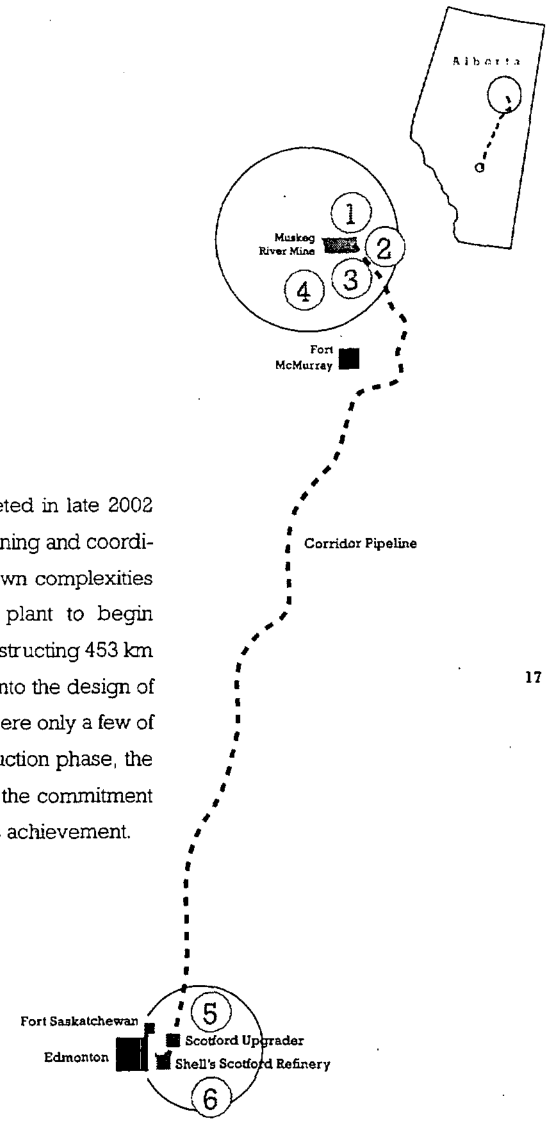
Stages of Production

	Process	Location
1.	Ore Preparation	Muskeg River Mine
2.	Extraction	Muskeg River Mine
3.	Froth Treatment	Muskeg River Mine
4.	Storage and Pipeline	Muskeg River Mine/Corridor Pipeline
5.	Upgrading	Scotford Upgrader
6.	Blending and Marketing	Scotford Upgrader

The Athabasca Oil Sands Project is one of the world's largest construction projects in terms of size and complexity. Behind that effort was Western and its partners and their combined



Construction of the Athabasca Oil Sands Project was completed in late 2002 bringing to fruition a massive feat in engineering, design, planning and coordination. Each component of the mega-project introduced its own complexities and challenges: developing a Mine site and extraction plant to begin processing of one of the world's largest bitumen reserves; constructing 453 km of dedicated pipeline; and incorporating leading technology into the design of an Upgrader to produce high quality synthetic crude. Those were only a few of the monumental tasks involved. Throughout the entire construction phase, the Project maintained a world-class safety record – testament to the commitment of thousands of people who participated in such a momentous achievement.

world-class expertise.

Left to right:

Neil Camarta

Senior Vice President, Oil Sands
Shell Canada Limited

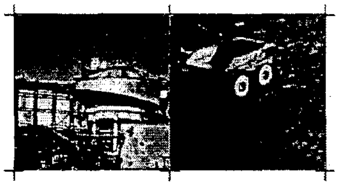
Paul Rogers

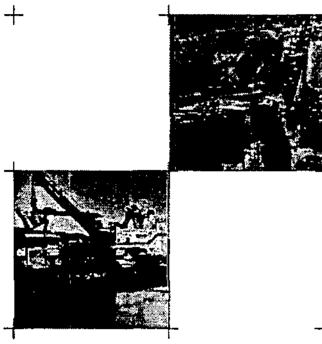
Manager, Oil Sands
Chevron Canada Limited

John Frangos

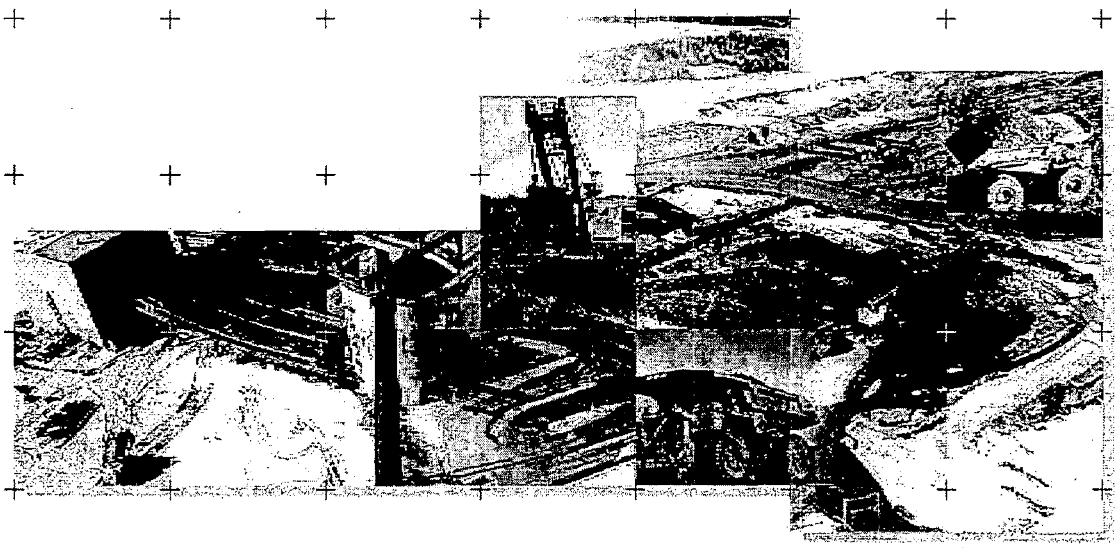
Executive Vice President and
Chief Operating Officer
Western Oil Sands Inc.

Mine site to market



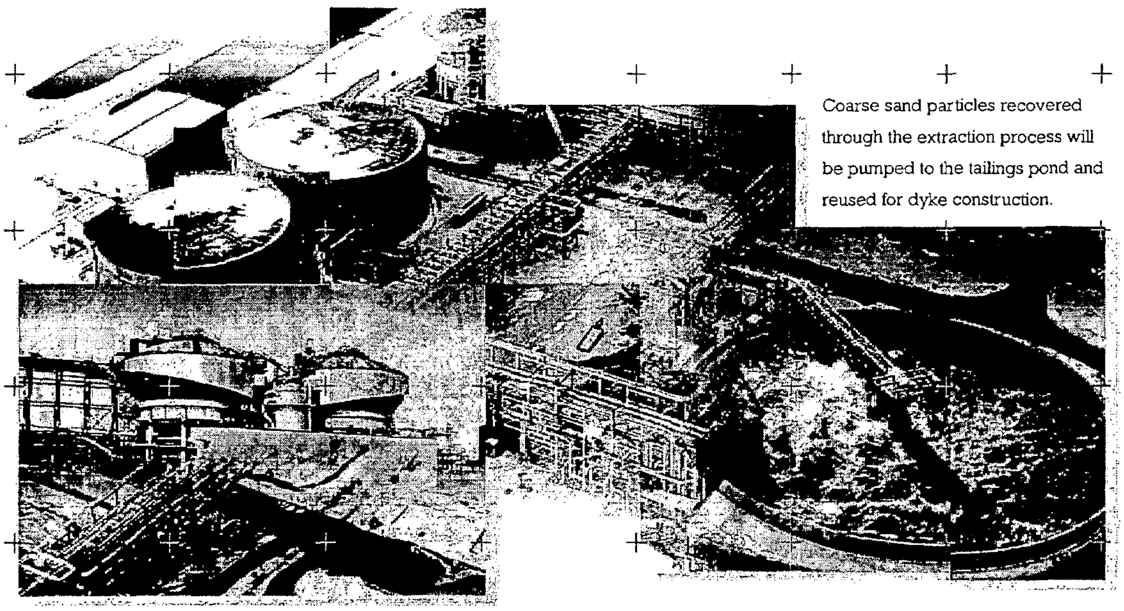


The mining fleet will consist of five electric shovels supported by twenty-three 400-tonne haul trucks as well as numerous graders, dozers and other support equipment.



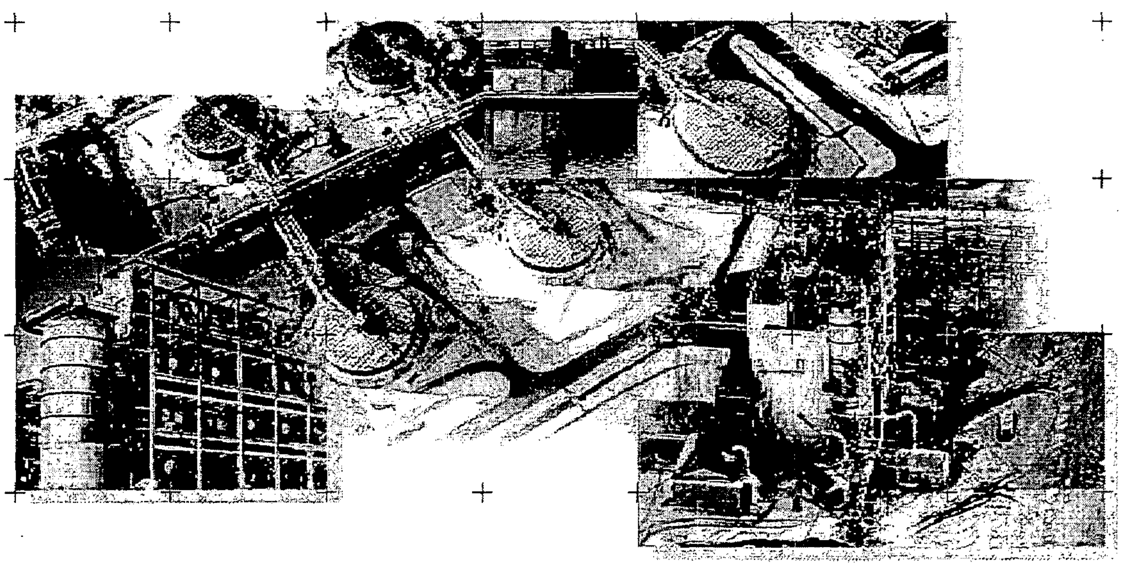
Ore is mined using traditional truck and shovel mining techniques. Two tonnes of oil sands ore are required to create one barrel of bitumen and one barrel of bitumen will create one barrel of synthetic crude. The mined ore passes through primary crushers, reducing the ore to chunks smaller than 16 inches and then sent to rotary breakers, which break the ore further into particles two inches in size or smaller using hot water. This creates a slurry, which conditions the ore and starts the separation process as it travels along a two-kilometre pipeline to primary extraction.

Extraction The rock/bitumen slurry moves through a pipeline to the extraction plant where sand, clay and other particles are separated from the bitumen. Air is introduced to the slurry as it enters two large primary separation vessels. The bitumen attaches to the air bubbles and rises to the surface as a bitumen-rich froth. The remaining sand and clay particles settle to the bottom and are pumped to tailings ponds. The addition of steam in a separate process removes the air bubbles and the bitumen is sent to two large storage tanks.



Coarse sand particles recovered through the extraction process will be pumped to the tailings pond and reused for dyke construction.

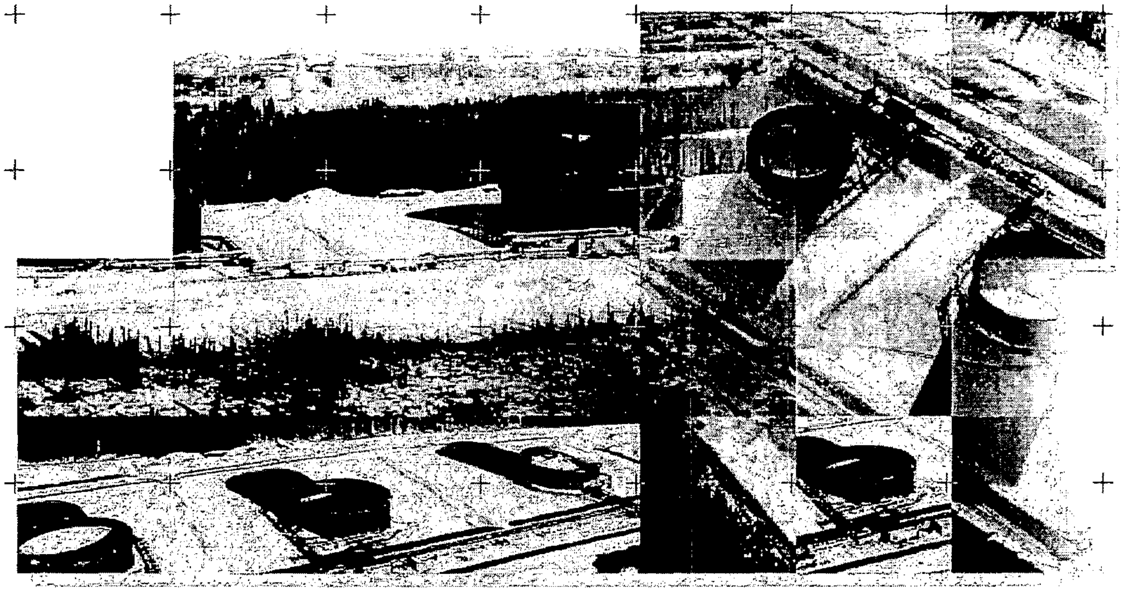
Solvent is recovered from the tailings and reused which, combined with solvent recovery from diluted bitumen (dilbit) delivered to the Upgrader via the Corridor pipeline system, achieves close to 100 per cent solvent containment within the process.

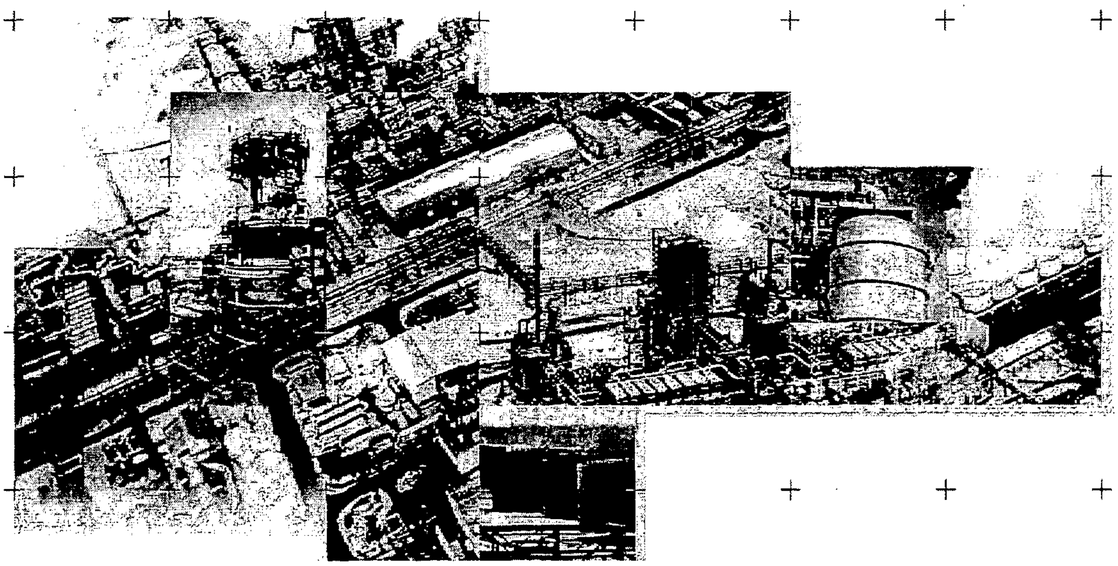


[illegible] The froth treatment process uses a counter-current decantation (CCD), solvent extraction process that is a unique application to oil sands, although it has been used extensively in other minerals extraction processes for many years. The bitumen froth is drawn from storage and solvent is added within this CCD circuit to separate out the remaining solids, water and heavy asphaltenes. The solvent washes the sand and ultimately recovers about 99 per cent of the bitumen and removes all of the sand, producing a very clean bitumen that is required in order for the Upgrader to run efficiently. The process yields a mixture of solvent and bitumen that is ready to be stored and transported to the Upgrader. The remaining non-bitumen solids are directed to the tailings stream once it passes through a solvent recovery process.

4 Storage and Pipeline Two large storage vessels at each end of the Corridor Pipeline store the dilbit and ensure a constant supply of dilbit is available to the Upgrader. These vessels each hold 300,000 barrels; in aggregate enough to keep the Upgrader in operation for eight days. Transportation of dilbit to the Scotford Upgrader is via a 453-kilometre, 24-inch pipeline. The solvent is removed at the Upgrader and transported via a parallel 12-inch pipeline back to the Mine site for re-use.

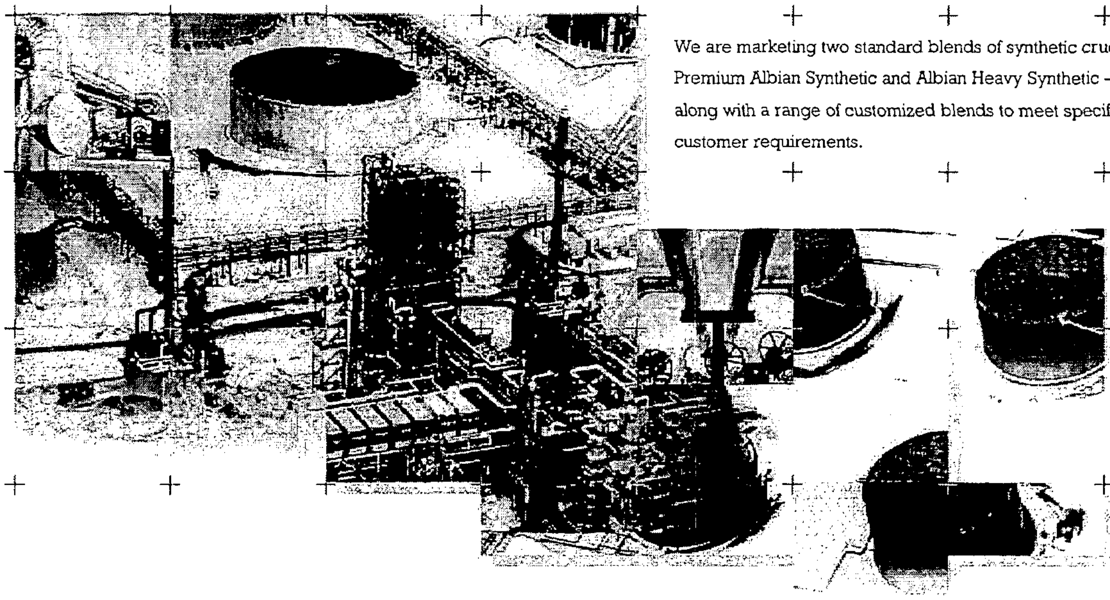
At design capacity of 155,000 barrels per day of bitumen, the pipeline will carry 228,000 barrels per day of diluted bitumen and approximately 73,000 barrels per day of diluent in the return line.



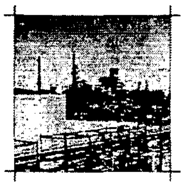


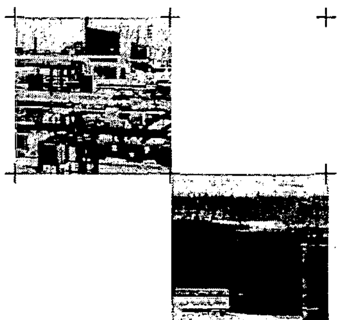
Upgrading In its raw form, bitumen is too high in carbon and sulphur to be of optimal value in the marketplace. The bitumen at the Scotford Upgrader is upgraded using both hydro-treating and hydro-conversion processes which remove sulphur, add hydrogen and break the heavy carbon molecules, and with the addition of non-bitumen feedstocks, yield 130,000 barrels per day of synthetic crude oil and 60,000 barrels per day of heavier vacuum gas oil. The hydrogen addition process increases the bitumen volume by about three per cent with no waste products. In addition, other feedstock is subsequently added to create different blends of crude.

5 Marketing We will market our share of volumes to refineries in North America and internationally. To maximize pricing, we will act as an independent, full-service marketer, providing customers with a stable, long-term supply of high quality crude, technical support, customized blends and pipeline transportation, as required.



We are marketing two standard blends of synthetic crude – Premium Albian Synthetic and Albian Heavy Synthetic – along with a range of customized blends to meet specific customer requirements.





Hydrogen conversion technology is an environmentally friendly upgrading process producing lower levels of sulphur dioxide and eliminating any waste coke by-products.

Gerry Luft

Vice President, Marketing

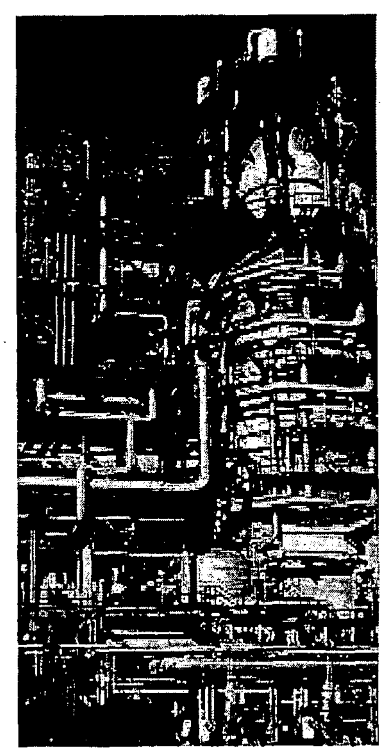
We are focused on evolving into an independent full-service marketer, and are building long-term relationships with refiners in North America and internationally, to supply them with our high quality

Marketing

Entering 2003, we have moved past the construction phase of the Project into a marketing and operating environment. High priority is being given to the development of our marketing profile as synthetic crude oil production commenced in the first quarter of 2003. An aggressive strategy to market our share of production will be supported by assisting refining customers with their displaced volumes through the marketing and brokering of crude oil to third parties. This will position us as one of a handful of independent crude oil brokers in Canada and in a strong position to market our own synthetic crude production.

Our marketing strategy is based on maximizing the price received for our synthetic crude, while building long-term relationships and industry presence among the refining community in the North American and in the international marketplace. Our ability to create strong customer relationships is of particular significance, considering the large production volume increases expected from the Joint Venture's planned project expansions.

Our share of crude oil available for sale out of the Upgrader is expected to be approximately 38,000 barrels per day including feedstocks by the third quarter of 2003. Over the next few years, debottlenecking and expansion could increase our share of crude oil available for sale to about 55,000 barrels per day including feedstocks. Development of a second stand-alone mine, the Jackpine Mine, is a longer term project that, over the next 10 years,



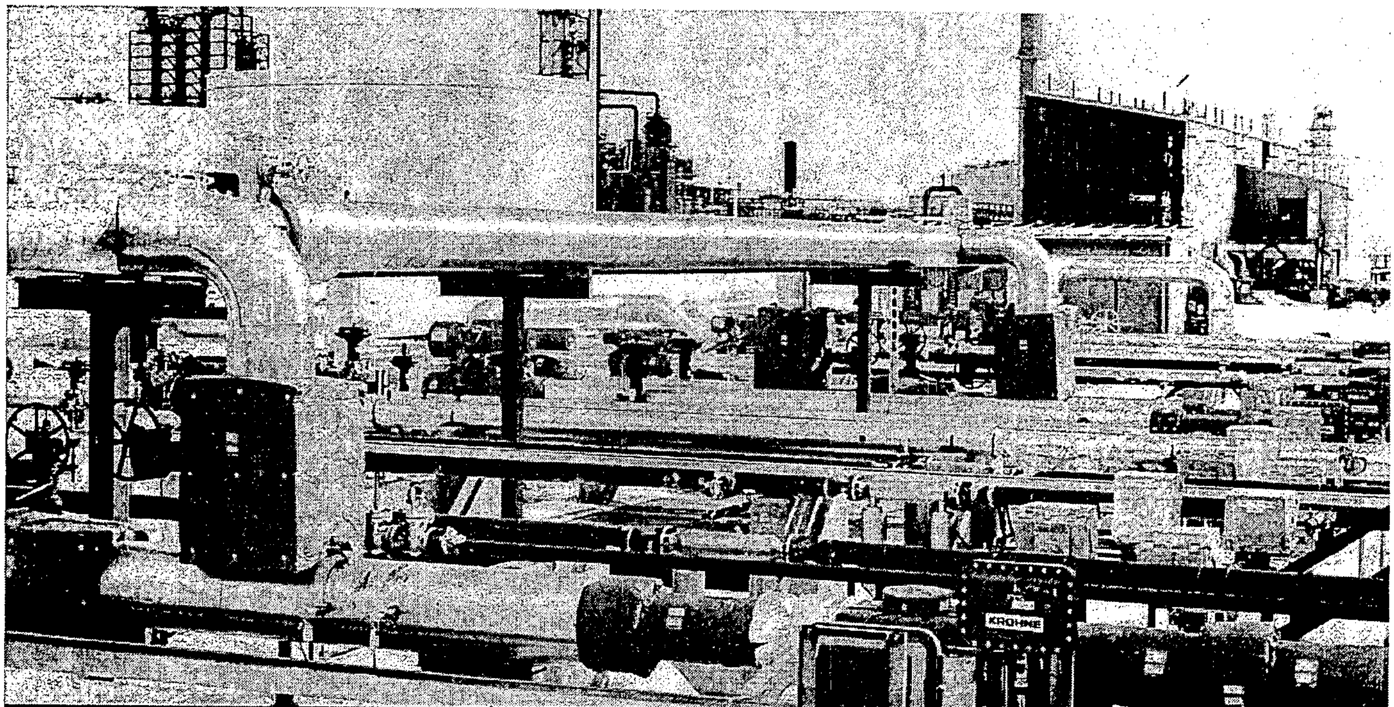
synthetic crude.

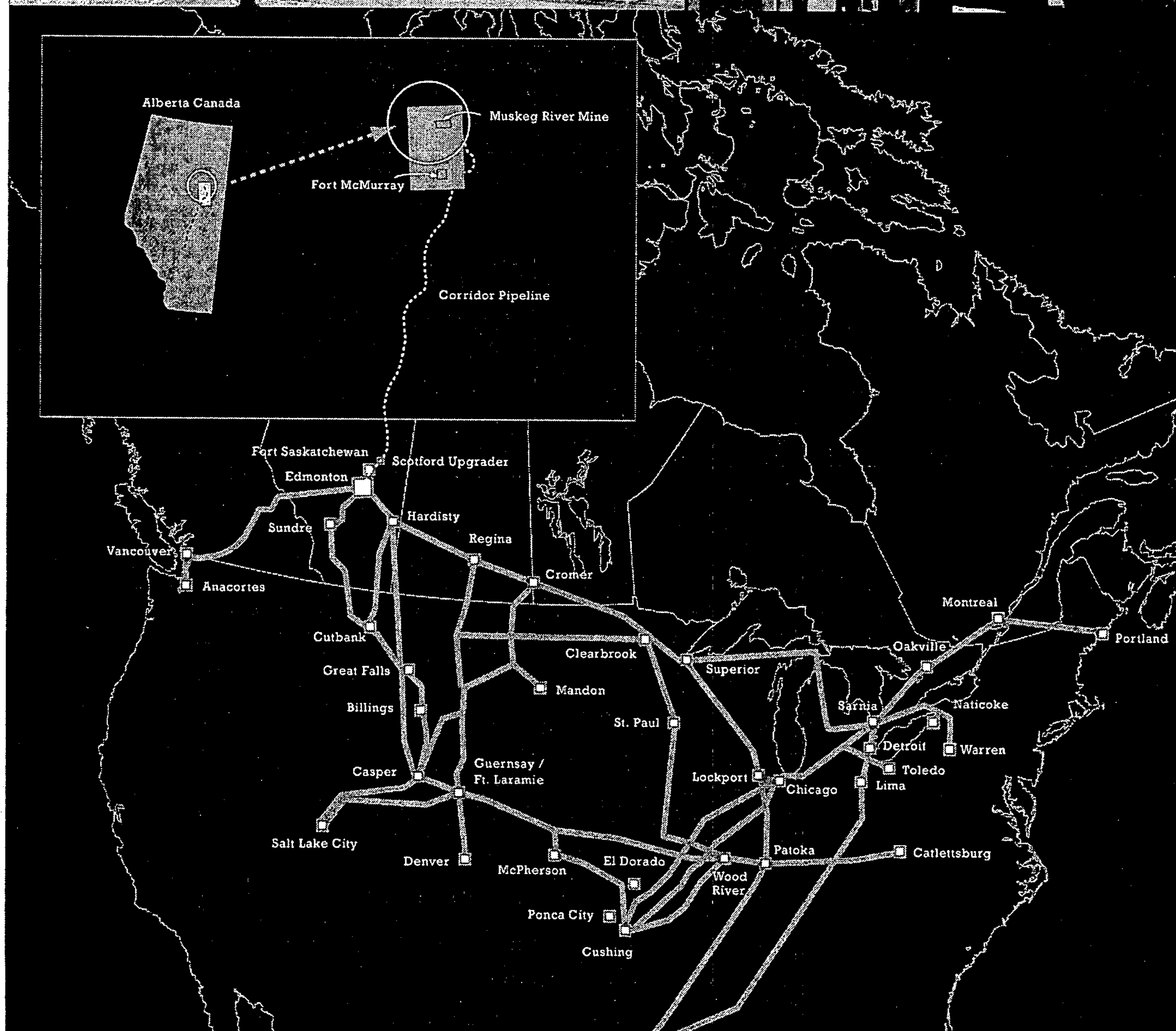
will augment total project production to 525,000 barrels per day of bitumen. By this time we expect to be producing and marketing our share of crude oil available for sale which will be close to 125,000 barrels per day of high quality synthetic crude, including feedstocks, in addition to marketing and brokering displaced refinery volumes. The long life nature of oil sands reserves will provide our customers with a secure long-term supply of feedstock for their refinery operations.

As we move to being an aggressive full-service marketer we are able to capitalize on a number of key competitive advantages:

- We are operating as an independent producer; we are not affiliated with any single refinery. This means that we have the flexibility to focus on every customer and provide specific services to meet their needs – from brokering or swapping volumes to acquiring pipeline transportation.
- While our independence sets us apart from our partners, it is our association with Shell and ChevronTexaco that provides considerable refining expertise and access to technical support for our customers.
- Our ultimate advantage is the high quality of our synthetic crude and the value-added advantages for the refining industry. By the third quarter of 2003, our share of crude oil available for sale will include:
  - 26,000 barrels per day of a combination of light synthetic crude, which is branded as Premium Albian Synthetic, and a heavier crude, known as Albian Heavy Synthetic, which is well suited to heavy crude coking refineries; and
  - 12,000 barrels per day of vacuum gas oil, which will be sold to Shell under a long-term contract.
- We will be able to respond to our customers' needs by adjusting and customizing the characteristics of crude being blended for shipment at the Scotford Upgrader.
- Beyond customizing blends, we will be able to identify and respond to specific requirements of the refining industry by developing customized solutions.
- As a result of specific technological features of our upgrading processes, our synthetic crude offers customers superior qualities for processing, blending and customizing products. This flexibility can be particularly attractive to improving refinery efficiencies.
- The low sulphur content of our synthetic crude is of particular benefit to refineries which are required to meet low sulphur fuel specifications.
- Our synthetic oil has the advantage of higher cetane and a higher jet smoke point versus other synthetic crudes.
- The bitumen/diluent flows through the Corridor Pipeline to the Scotford Upgrader and, following upgrading, the synthetic crude is transported through another dedicated pipeline to the crude oil terminals near Edmonton. This allows us to maintain the integrity and ultimately the quality of our synthetic crude.

Through direct sales to refineries and the full-service capacity to market volumes for refineries and/or producers of crude oil, we are positioned to build strong market presence and long-term relationships, thereby realizing maximum value for our high quality synthetic crude.

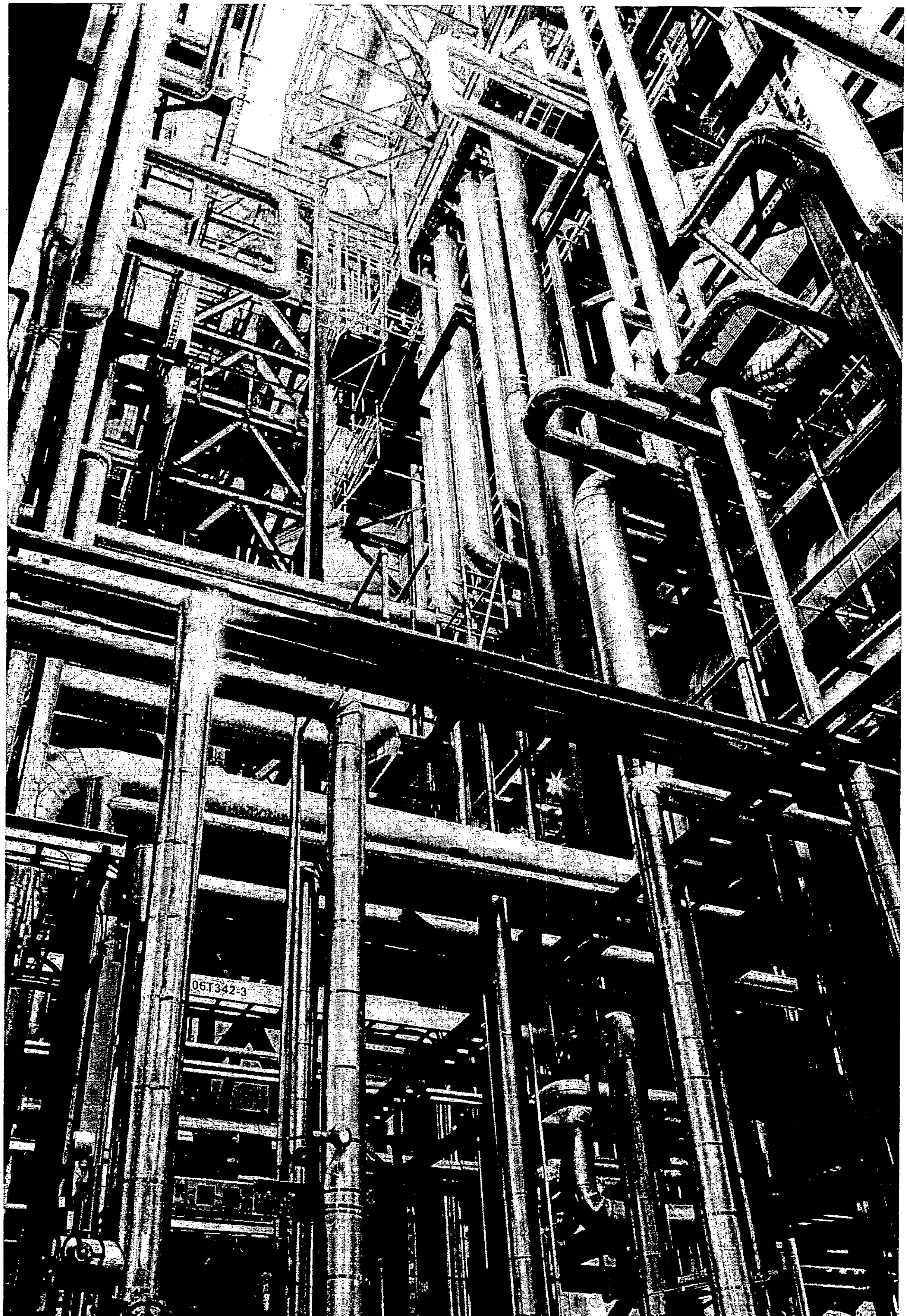




Pipeline Delivery System

Major Common Carrier Oil Pipelines

Cities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Sustainable Development

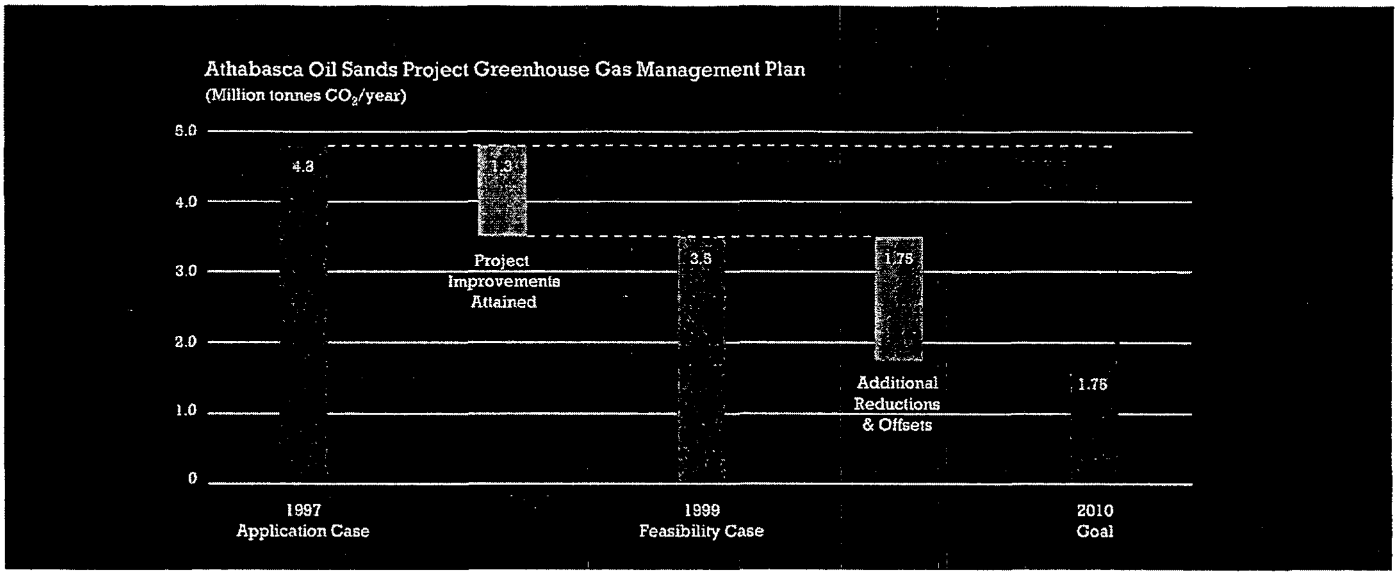
The Athabasca Oil Sands Project has been designed and constructed around the principles of delivering profitability within the directive of sustainable development. In the view of Western and its partners, sustainable development involves the integration of environmental, social and economic considerations in the decision-making and execution process. Ultimately, a commitment to sustainable development and corporate responsibility is critical to sound operations, and to expansion in the future.

A crucial element of sustainable development has been the Project partners' strategy of extensive and open dialogues with key stakeholders: local communities, First Nations, governments and individuals, among others. This commitment includes training of the Project's employees to enhance knowledge and the application of sustainable development practices. This open communication process has led to significant investments to ensure the continuation of sustainable development. First Nations' involvement in construction and now operations continues to be win-win. Community support through our community relations program continues to grow as both the Mine and the Upgrader become welcome and established partners in their respective communities.

One area of emphasis has been to balance the economic benefits of the Project with the needs of the local community in a meaningful and sustainable way. The Project employed over 15,000 staff and contractors at its peak of construction. A key thrust has been to help expand the scope and capacity of local business, while providing employment to local communities and Aboriginal businesses. The Project has yielded $50 million in contracts to Aboriginal businesses, half of which went to businesses near Fort McKay, the closest Aboriginal community. As one example of the focus on sustainability, the Fort McKay Group of Companies had expanded its capabilities and services from brush clearing to becoming a low-cost mining contractor and has entered into a longer-term alliance with Albian Sands Energy, the company formed to operate the Mine north of Fort McMurray. This commitment to working with local communities to provide social and economic benefits is critical to ongoing operations and to expansions in the future.

Environmental considerations have been fundamental to the Project's design and development. This dedication includes minimizing impacts on wildlife and the landscape, including sensitivity to biodiversity, water, air and the people living and working near the Project.

In developing the Mine site, land disturbance was minimized with the benefit of leading technology and land-use practices. To ensure minimal impacts to the health of people and crops in the area, the Project has invested in programs to test for levels of organic compounds, nitrogen oxides and ground level ozone. As one example of stakeholder communication, we and our partners are continuing to build



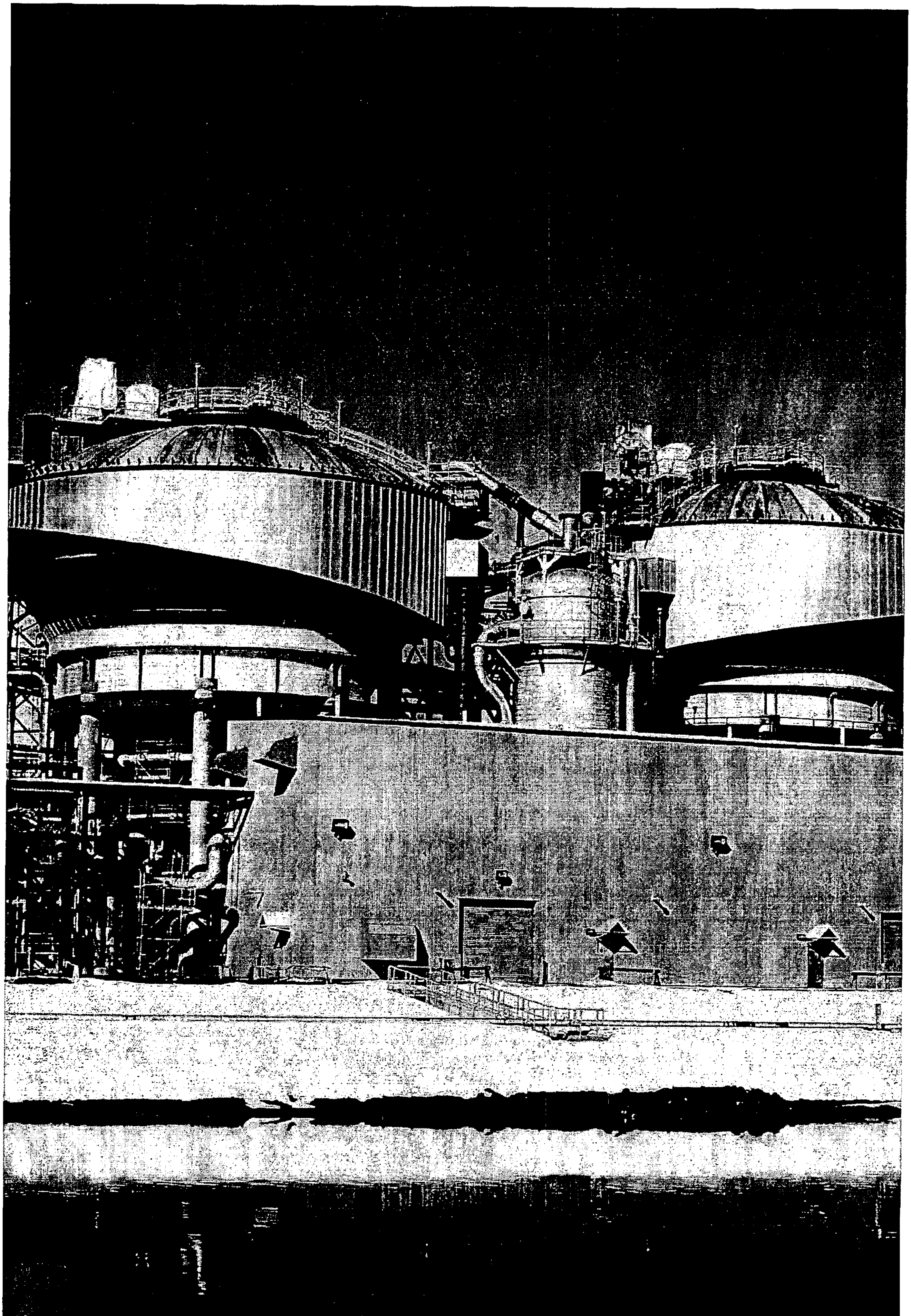
on their commitment to the Cumulative Environmental Management Association, a regional multi-stakeholder program to assess and manage the combined effects of industry on the environmental capacity of the Wood Buffalo area ecosystems.

With a longer-term view, Albian Sands Energy is working with a number of local stakeholders' groups on a final reclamation plan for the Muskeg River Mine. Working in partnership with stakeholders is providing the opportunity to integrate Traditional Environmental Knowledge, an understanding of how past generations lived off the land. The establishment of this important dialogue is designed to create a mutually beneficial process that will lead to a reclamation plan that will meet the end-use needs of stakeholders.

Air quality is of particular importance to the project, and has taken on greater significance with the federal government's ratification of the Kyoto agreement. As part of a Voluntary Climate Change Action Plan, the Joint Venture has substantially reduced emission targets for the Project. As it stands today, the Project will be starting up with emission that are 27 per cent lower than the original case that was approved by the AEUB. We have achieved this through the addition of cogeneration units, the use of waste hydrogen from a neighbouring facility and a variety of process improvements. Our goal is to further reduce emission by another 50 per cent by 2010 through a combination of energy efficiency projects.

To achieve this goal, the partners are pursuing a multi-faceted plan, which will include energy efficiency projects, investigation of cleaner technology, the purchase of domestic and international offsets and tree-planting offset programs. In one offset project completed in 2001, funding was provided for the planting of 160,000 trees in Strathcona County, the site of the Scotford Upgrader. The planting program is estimated to yield a CO_2 offset of more than 100,000 tonnes over the trees' lifetime. In 2003, a series of on-site workshops will be conducted to help define process improvements and emission reduction opportunities, which can be incorporated as debottlenecking and expansion activities are undertaken.

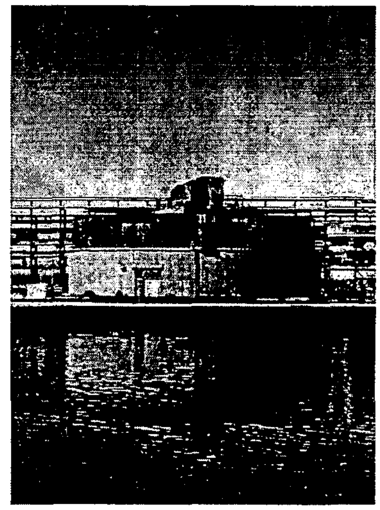
Sustainable development will continue to be a guiding principle in future expansions and mine development. Western and its partners are capitalizing on the experience and knowledge gained during the consultation and regulatory process for development of the current mine and upgrader. As future development proceeds, Western and its partners will be guided by the corporate responsibility inherent in sustainable development, and the commitment to communication and remaining a positive force for all stakeholders.



David A. Dyck
Vice President Finance
and Chief Financial Officer

2003 will be a significant
as we shift from construction
and development to generating
revenue and cash flow.
Our 2003 results will provide
comparable data for

Management's Discussion & Analysis



The following discussion of financial condition and results of operations should be read in conjunction with the Consolidated Financial Statements and Notes. It offers Management's analysis of our financial and operating results and provides estimates, where possible, of our future financial and operating performance based on information currently available. Actual results may vary from estimates and the variances may be significant.

Overview

Western Oil Sands Inc. is a Canadian oil sands corporation which holds a 20 per cent undivided ownership interest in a multibillion dollar Joint Venture to exploit the recoverable bitumen reserves and resources found in certain oil sands deposits in the Athabasca region of Alberta (the "Project") and to pursue other oil sands opportunities. Shell Canada Limited ("Shell") and Chevron Canada Limited ("ChevronTexaco") hold the remaining 60 per cent and 20 per cent undivided ownership interests in the Joint Venture, respectively. The Project, which includes facilities owned by the Joint Venture and third parties,

measurable performance.

will use established processes to mine oil sands deposits, extract, and upgrade the bitumen into synthetic crude oil and vacuum gas oil, or VGO.

The Joint Venture will develop the western portion of Lease 13, a large oil sands lease in the Athabasca region of northeastern Alberta, Canada, held by the owners and granted by the Government of Alberta. The western portion of Lease 13 contains approximately 1.7 billion barrels of proved and probable reserves and is sufficient for 30 years of non-declining bitumen production at a rate of 155,000 barrels per day. Western is entitled to participate in future expansion opportunities, including in respect of Lease 13 and on three other nearby oil sands leases owned by Shell, referred to as leases 88, 89 and 90.

Our main role is to provide construction and operating expertise for the Mine and extraction plant. Our personnel includes 14 mining professionals who have accumulated over 350 man years of experience derived from a variety of global mining and resource extraction projects, who provide the management of the Mine and extraction facilities and who have the expertise to develop growth opportunities on the remaining leases. We have employed the same proven technologies and processes in the Athabasca Oil Sands Project that have been used successfully in other resource extraction projects around the world.

Shell has extensive refining experience and its organization is primarily responsible for the construction and operation of the Scotford Upgrader, as well as providing the overall Project administration and accounting functions.

ChevronTexaco provides a key management support role at both the Mine and the Upgrader sites. ChevronTexaco is a recognized world-leader in catalyst and hydro-treatment technologies, which are key elements in the successful upgrading of the mined bitumen.

Highlights

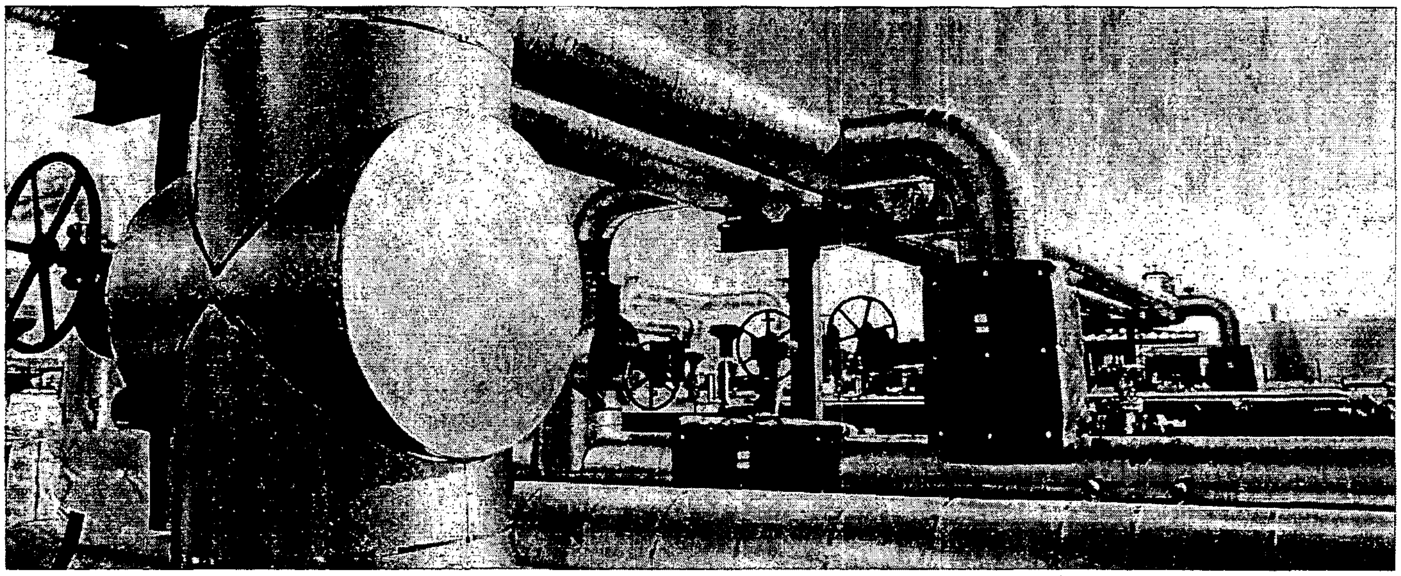
- We incurred $527.5 million of capital expenditures during 2002, $519.9 million of which were direct Project costs with the balance comprised of corporate assets.
- During the year we issued US$450 million of corporate bonds and established new bank credit facilities totalling $150 million.
- We raised $50.2 million in additional equity capital in February 2003, as a direct result of not having received any of the insurance proceeds from our $200 million cost overrun insurance policy.
- Construction of the Project was completed in 2002 and both the Muskeg River Mine and the Scotford Upgrader were commissioned for start-up.
- Mining operations commenced prior to year-end 2002 following which diluted bitumen was delivered into the Corridor Pipeline system en route to the Scotford Upgrader.

Operations

Project Update

Construction of the Project was completed in 2002 and all the major milestones have been met, despite the challenges of the lack of skilled labour and the management of related productivity issues that were experienced throughout the year.

Northern Alberta experienced an unprecedented demand for labour in the second half of 2001, largely as a result of other industry projects experiencing delays in completion and continuing to utilize craft labour that was expected to be available earlier for our Project. The restricted availability of skilled craftsmen had an adverse impact on productivity at our project beginning in 2001. Labour productivity continued to be lower than expected throughout 2002 and this applied significant cost pressure to the Project throughout the year. A combination of these and other factors led to a 59 per cent increase in the forecasted cost of the Project from the original budget of $3.5 billion (our share $709 million), to $5.6 billion (our share $1.12 billion).



All units at both the Muskeg River Mine and the Scotford Upgrader have been turned over to operations for commissioning and start-up. The first production of synthetic crude out of the Upgrader was achieved by the end of the first quarter of 2003.

Key Project milestones achieved in the year include:

- The ATCO Gas Pipeline supplying gas to the upstream cogeneration plant was completed during the year. Line fill with natural gas occurred in January 2002.
- The Corridor Pipeline was completed and first diluent line fill was injected in April 2002.
- In August 2002, first ore was mined and processed through the primary extraction facilities producing bitumen froth at the Muskeg River Mine.
- In August 2002, the Project took delivery of the first mining truck and electric shovel that will be used in the mining operations. The Project will ultimately have a mining fleet consisting of twenty-three 400-ton mining trucks and five electric shovels.
- Construction, testing and commissioning of the ATCO Cogeneration Facilities at both the Muskeg River Mine and the Scotford Upgrader were completed by the fourth quarter of 2002.
- By November 30, 2002, mechanical completion was achieved for all aspects of the Project, both at the extraction plant and the Scotford Upgrader.
- First bitumen production at the Muskeg River Mine started on December 29, 2002, followed immediately with the shipment of diluted bitumen into the Corridor Pipeline system for delivery to the Scotford Upgrader.

On January 6, 2003, a fire occurred in the froth treatment area at the Muskeg River Mine, caused by a hydrocarbon leak arising from the failure of a piping connection. The fire did not cause significant damage to major process equipment or piping systems. Damage was mainly limited to electrical cables, instrumentation and insulation in the solvent recovery area of the froth treatment plant and subsequent damage to pipes as a result of freezing. The original estimate of repair costs for the fire was in the order of $75 million ($15 million our share). Although not yet determined, the final costs will be higher than the original estimate and will include additional costs to repair the freeze damage. We expect that repairs will be completed and production of bitumen will resume with first synthetic crude oil production from the Scotford Upgrader scheduled by the end of the first quarter of 2003. We expect to draw on extensive project insurance coverage to recover repair costs.

Capital Expenditures

Construction activities have been conducted under a Joint Venture agreement whereby we participate in the operations of the Project to our 20 per cent working interest and are responsible for 20 per cent of the costs. During 2002, our share of Project capital expenditures totalled $519.9 million compared to $432.8 million for 2001. These expenditures included construction costs of the Project at the Muskeg River Mine and the Scotford Upgrader as well as direct capitalized finance and other costs of $55.3 million in 2002, up from $10.7 million capitalized in 2001. The capitalized costs consist primarily of bond and bank interest and stand-by fees that are being capitalized during the construction period as is consistent with industry practice and our policy.

In 2002 we also spent $7.6 million on corporate assets and certain other capitalized costs not related to the Project.

We capitalized a further $15.7 million in 2002 related to our share of the costs for construction of the Hydrogen Manufacturing Unit (HMU) at the Scotford Upgrader, up from $17.8 million in 2001. The HMU costs are being financed by a capital lease. An amount of $2.0 million related to other accrued finance costs was also capitalized.

Capital Assets

($millions)	2002	2001	2000	1999	Since inception
Expenditures					
Muskeg River Mine	**219.0**	212.1	66.7	3.9	501.7
Scotford Upgrader	**245.6**	210.0	118.0	5.5	579.1
Capitalized finance costs	**53.0**	9.5	6.4	–	68.9
Entry fee	**(0.4)**	1.2	–	34.2	35.0
Shell interest [1]	**2.7**	–	–	–	2.7
Project expenditures	**519.9**	432.8	191.1	43.6	1,187.4
Corporate assets	**7.6**	0.8	1.0	3.1	12.5
Cash expenditures	**527.5**	433.6	192.1	46.7	1,199.9
Non cash capitalized costs					
Shell Fees and interest [1]	–	6.4	7.3	40.0	53.7
HMU	**15.7**	17.8	17.3	–	50.8
Capitalized finance costs	**2.0**	–	–	–	2.0
Corporate assets	–	–	–	1.1	1.1
Total	**545.2**	457.8	216.7	87.8	1,307.5

[1] Shell fees and accrued interest liability were repaid in full in April 2002 out of proceeds of the Senior Secured Notes offering.

The forecast cost of the Project is $5.6 billion (our share $1.12 billion), up from $4.8 billion ($957 million our share) that was forecast at December 31, 2001. The impact of this cost increase is to increase our proved plus probable reserve development cost from $2.85 to $3.35 per barrel. On the basis of this level of expenditures, we have funding arrangements that are sufficient to cover our share of commitments. In addition we believe that a portion of these increased Project costs fall within the scope and coverage of our Cost Overrun Insurance policy. (See discussion in Financial Risks.)

Capital expenditures are expected to be lower in 2003 as construction of the Project was completed in 2002 and we are in the commissioning and start-up phase of the Project. Capital expenditures for 2003 are estimated at $65 million and represent deferred operating expenses during commissioning and start-up, as well as maintenance capital expenditures throughout the year.

Reserves

Gilbert Laustsen Jung Associates Ltd. (GLJ), an independent engineering firm located in Calgary, evaluates our reserves. The following table summarizes the Project reserves and our share of those reserves as at January 1, 2003, based on GLJ's forecast of escalating prices and costs:

	Gross Project Reserves (MMbbls)	Ownership Interest Reserves (MMbbls)	Net After Royalty (MMbbls)	Present Values of Estimated Future Net Cash Flow Before Income Taxes 0%	10%	15%	20%
				($ million)			
Proved	1,111	222	202	2,960	1,302	972	766
Probable	570	114	96	1,956	340	195	134
Risked probable (50%)	285	57	48	978	170	97	67
Proved plus 50% probable	1,396	279	250	3,938	1,472	1,069	833
Proved plus probable	1,681	336	298	4,916	1,642	1,167	900

This analysis by GLJ includes only those reserves from the western portion of Lease 13, which is the initial area being mined by the Joint Venture. These reserves will provide a reserve life of approximately 30 years based on anticipated bitumen production rates of 155,000 barrels per day (our share 31,000 barrels per day).

In addition, we are entitled to participate in expansion opportunities with the Owners, on the remainder of Lease 13 and on three nearby oil sands leases owned by Shell, namely Leases 88, 89 and 90. The following table outlines the potential resources available under these expansion opportunities:

Area	Total Resources (MMbbls)	Western's Share (MMbbls)
Remainder of Lease 13 and Lease 90	3,200	640
Leases 88 and 89	3,900	780
	7,100	1,420

Financial Results

Apart from our interest in the Athabasca Oil Sands Project, we have no other assets nor do we have any other on-going operations. Our operating activities commenced with Project start-up, which occurred at the Muskeg River Mine in December 2002. We expect to be moving into commercial production in the second quarter of 2003 following production of synthetic crude oil which occurred in the first quarter of 2003 and will be reporting operating results for the balance of 2003 in our quarterly interim reports.

General and Administrative Expenses

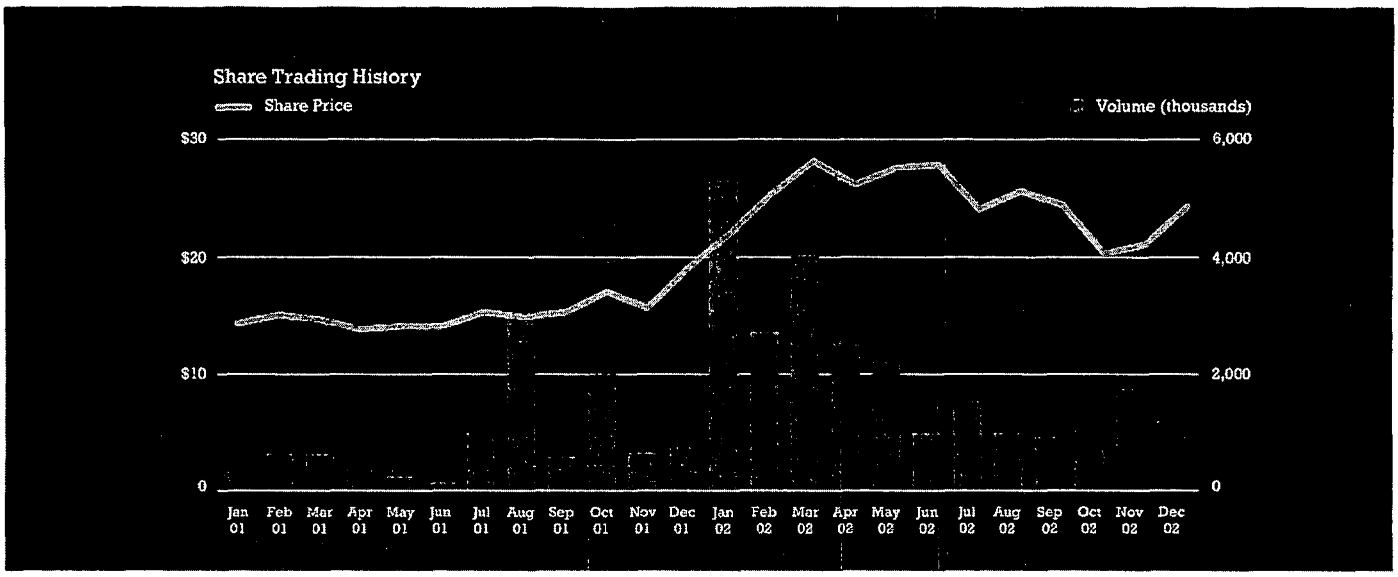
General and administrative expenses for 2002 totalled $5.7 million (2001 - $5.3 million). The increase is primarily due to the addition of marketing and administrative personnel as we prepare to enter our operating phase. General and administrative expenses are expected to increase modestly in 2003 commensurate with additional staff or consultants that may be required throughout the year.

Royalties

The current royalty system for oil sands consists of an initial royalty of one per cent of the gross revenue on the bitumen produced (based on its value prior to upgrading) until we have recovered our share of all the capital costs associated with the Muskeg River Mine and Extraction plant, together with a return on capital equal to the Canadian federal long-term bond rate. After full capital cost recovery, the royalty shall be the greater of one per cent of the gross revenue on the bitumen produced and 25 per cent of net revenue on the bitumen produced. We will be paying royalties at the one per cent rate once we start producing. We estimate that payout will not be achieved for several years, after which we will be paying royalties at the higher rates. The timing of this will depend in part on the prices we receive for our production as well any additional capital costs incurred through expansion activities.

Interest Expense

During 2002 we incurred $48.1 million in interest expense on our debt obligations (2001 - $11.0 million). These included the long-term bonds, the bridge facility, our other bank facilities and the Shell fees loan. This debt has been used to finance construction costs and, accordingly, all interest is being capitalized until the Project reaches commercial production, which we expect by the second quarter of 2003. (See Capital Assets.) Capitalized interest will be written off over the term of the Project. Once commercial production is attained, interest costs will be expensed in the period to which it relates.



Income Taxes

Large Corporations Tax increased to $2.9 million from $1.5 million last year as a direct result of the expansion of our capital base.

As we have not had any operating revenues to date, we have not yet earned taxable net income. At December 31, 2002, we had approximately $1.2 billion of loss carry forwards and tax pools. In addition, we had $8.7 million of financing issue costs, which can be used to offset future taxable income. The potential future benefit relating to the loss carry forwards and share issue costs has been recorded in the financial statements, resulting in a future income tax recovery of $22.5 million. This asset is offset by a future income tax liability of $23.0 million arising from the renunciation of deductions for flow-through shares, resulting in a net future tax liability of $0.5 million, with share capital being reduced by the $23.0 million tax effect of the renunciations.

Tax Pools

($ thousands)	December 31 2002
Canadian Exploration Expense	$ 45,214
Canadian Development Expense	15,993
Canadian Exploration and Development Overhead Expense	2,704
Cumulative Eligible Capital	4,039
Capital Cost Allowance	25,632
Accelerated Capital Cost Allowance	1,031,616
Total	$ 1,125,198

Net Loss

Corporate expenses totalled $28.6 million for 2002 and included an amount of $22.8 million representing the one-time write-off of deferred financing costs related to credit facilities that were replaced by the US$450 million Senior Secured Notes offering in April 2002. Excluding the write-off, we incurred expenses of $5.9 million, compared to $5.5 million in 2001, an increase that reflects the expected growth in corporate activities as we move towards start-up. As we do not yet have revenues from on-going operations to offset these costs, our net loss was comprised primarily of the corporate expenses net of a future income tax recovery arising from the recognition of the tax benefit relating to loss carry forwards. The net loss attributable to Common Shareholders for 2002 was $10.3 million ($0.21 per share) compared to $7.0 million ($0.17 per share) for the year ended December 31, 2001.

Quarterly Information

($millions, except per share amounts)	2002 Q1	2002 Q2	2002 Q3	2002 Q4	Total
Capital Expenditures	$ 110.0	$ 133.2	$ 145.3	$ 139.0	527.5
Long-term Debt	418.5	683.4	713.6	775.8	775.8
Cash Flow from Operations	(1.7)	(1.9)	(1.8)	(3.2)	(8.6)
Cash Flow per Share	(0.03)	(0.04)	(0.04)	(0.07)	(0.18)
Loss Attributable to Common Shareholders	(1.8)	(24.7)	(1.8)	18.0	(10.3)
Loss per Share	$ (0.04)	$ (0.51)	$ (0.04)	$ 0.38	(0.21)

($millions, except per share amounts)	2001 Q1	2001 Q2	2001 Q3	2001 Q4	Total
Capital Expenditures	$ 77.9	$ 117.4	$ 117.4	$ 120.9	433.6
Long-term Debt	–	110.8	197.8	279.5	279.5
Cash Flow from Operations	(1.2)	(1.3)	(1.6)	(2.7)	(6.8)
Cash Flow per Share	(0.03)	(0.03)	(0.04)	(0.06)	(0.16)
Loss Attributable to Common Shareholders	(1.3)	(1.3)	(1.6)	(2.8)	(7.0)
Loss per Share	$ (0.03)	$ (0.03)	$ (0.04)	$ (0.07)	(0.17)

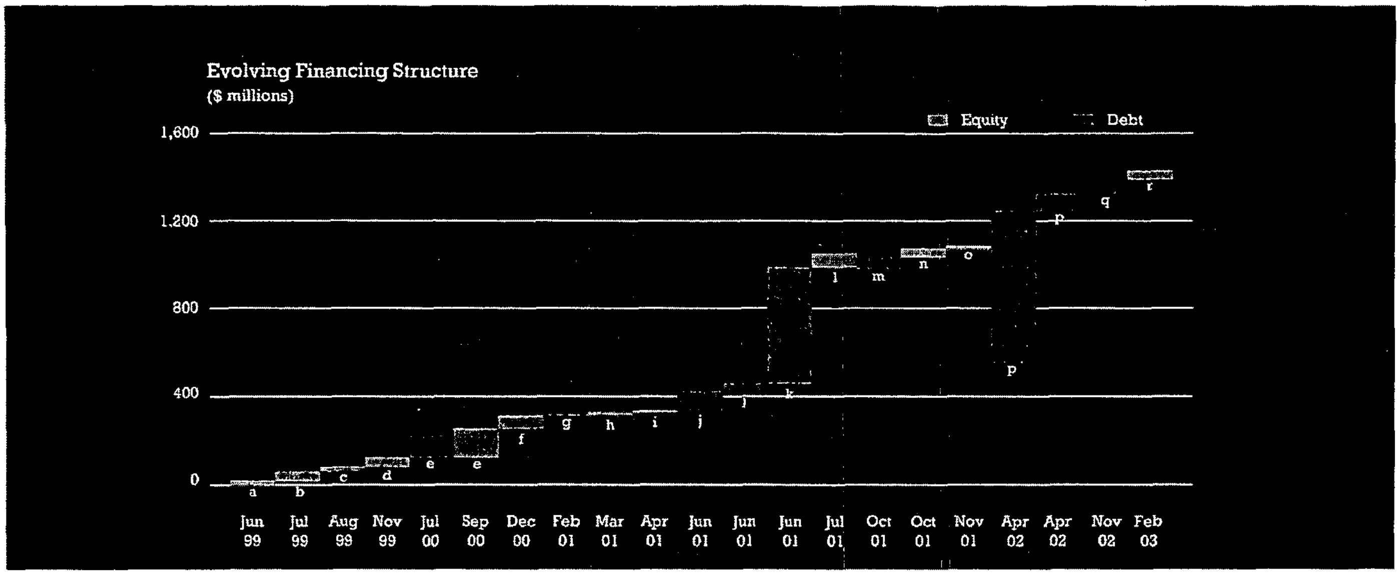
Financial Position

It was our stated intention at the start of the year to replace our senior credit facility with long-term debt financing. In the second quarter of 2002 we met this objective with the issuance of US$450 million of Senior Secured Notes, bearing interest at 8.375%, and maturing on May 1, 2012. The net proceeds of this offering were used to repay all amounts outstanding under our existing $535 million Senior Credit Facility, repay all amounts due to Shell and to fund our share of remaining construction costs for the Project. The $535 million Senior Credit Facility was cancelled upon repayment.

In conjunction with the offering, we established a new $100 million senior credit facility with a syndicate of chartered banks; $75 million of which will primarily be used to fund the first year's debt service under the offering as well as construction completion costs; the remaining $25 million is for working capital and letter of credit requirements. At December 31, 2002, $45.0 million had been drawn under this facility, with letters of credit issued in the amount of $15.4 million.

We maintain our $88 million bridge note purchase facility, due October 2003, with a Canadian chartered bank. At December 31, 2002 the full $88 million was drawn and outstanding on this facility (2001 – $NIL). The amounts drawn under this facility are deemed to consist of both an equity and a liability component, recognized as convertible notes in the financial statements. The initial carrying amount of the equity component is adjusted for accretion to bring it up to the stated principal amount of the facility at maturity. This accretion is charged to the deficit.

In November 2002, we established a new $50 million working capital facility with a syndicate of Canadian chartered banks, primarily to fund our working capital requirements during start-up of the Project. At December 31, 2002, $20 million had been drawn under this facility. This working capital facility was increased to $75 million in January 2003 with the addition of another bank to the syndicate.



Equity Financing

In February 2003, we issued 2,050,000 Common Shares at a price of $24.50 per share for gross proceeds of approximately $50.2 million. The Common Shares were offered to the public on a bought-deal basis through a syndicate of underwriters led by TD Securities Inc. Net proceeds from the issue were used to fund remaining costs for the Project and related expenses, for general corporate purposes and to reduce some of our short-term borrowings.

Over the past three years one of our primary objectives has been to fund our share of construction costs and to ensure that the timing of proceeds from financings coincides with the funding requirements for the Project. We have consciously structured our financing activities to maximize the value for our shareholders by minimizing the amount of equity issued and to issue equity at successively higher prices. These activities have resulted in 22 separate financing transactions over the past three years totalling $2.2 billion of gross proceeds and $1.5 billion net of re-financings. The chart above and accompanying notes provide a snapshot of the debt and equity transactions that have allowed us to participate in this exciting Project.

a. In June 1999, we issued 11 common shares at nominal value to incorporate the Company and arranged a private placement of 6,096,343 Non-voting Convertible Equity Shares, 279,950 Class A Warrants and 823,707 Class B Special Warrants for aggregate gross proceeds of $21.0 million.

b. In July 1999, we arranged a private placement of 8,330,000 Units, each Unit consisting of one Non-voting Convertible Equity Share and three call obligations, for gross proceeds of $41.7 million. In conjunction with this offering, the agent for the placement received a commission of 138,071 Non-voting Convertible Equity Shares valued at $1.6 million and a fee for services in connection with the acquisition of our ownership interest in the Project was paid to the agent through the issuance of a further 200,000 Non-voting Convertible Equity Shares.

c. In August 1999, we arranged a private placement of 2,750,000 Units, each Unit consisting of one Non-voting Convertible Equity Share and 4.5 call obligations, for gross proceeds of $20.6 million.

d. In November 1999, we arranged a private placement of 4,705,882 Non-voting Convertible Equity Shares at a price of $8.50 per share for proceeds of $40.0 million.

These first four equity transactions were completed in December 1999.

e. In July 2000, we established a $100 million bridge facility with a Canadian Chartered Bank. This bridge facility was in place until September 28, 2000, when we completed an equity offering of 10,709,076 Non-voting Convertible Equity Shares, of which 1,491,084 were issued on a flow-through basis, for aggregate gross proceeds of $130.0 million. At this time the bridge facility was cancelled.

f. In December 2000, we completed our Initial Public Offering on to the Toronto Stock Exchange, which involved the issuance of 4,000,000 Common Shares for gross proceeds of $60.0 million.

g. On February 1, 2001, we filed two prospectuses qualifying the issuance of an aggregate of 34,033,029 Common Shares, 494,224 Class A Warrants and 465,188 Class B Warrants issuable upon the conversion or exercise, as the case may be, of the Non-voting Convertible Equity Shares, Class A Special Warrants, Class B Special Warrants and Warrant Options issued in prior years by the Corporation. Subsequently, in February and March 2001, the 465,188 Class B Warrants were exercised into Common Shares for aggregate gross proceeds of $3.7 million.

h. On March 14, 2001, we completed a private placement of 666,667 Class D Preferred Shares, Series A, for gross proceeds of $12 million. Each Class D Preferred Share is convertible into one Common Share prior to redemption, which is at our option at any time at a price equal to their issue price plus a cumulative dividend of 12 per cent per year compounded semi-annually until January 1, 2007, increasing by 3 per cent per quarter thereafter to a maximum of 24 per cent per year.

i. On April 27, 2001, we completed a private placement of 625,000 Common Shares at $16.00 per share issued on a flow-through basis, for gross proceeds of $10.0 million.

j. We entered into a bridge financing arrangement in March 2001 for up to $90 million, and a second bridge financing arrangement in June 2001 for $30 million, both of which were considered as equity for purposes of the Senior Credit Facility. These two bridge facilities totalling $120 million were required to be repaid by October 31, 2001.

k. We satisfied the conditions precedent on our $535 million Senior Credit Facility in June 2001 and commenced drawdowns under this facility to meet our ongoing commitments to the construction of the Project. The conditions precedent that were required were customary for facilities of this nature, and included a requirement that an aggregate of $400 million of our equity capital be expended on the Athabasca Oil Sands Project. The Senior Credit Facility was available for funding the budgeted construction costs of the Project of up to $485 million. Additionally, the Senior Credit Facility was available for pre-completion debt servicing, which included interest costs and fees under the Senior Credit Facility, of up to $50 million. Under the terms of the Senior Credit Facility, we were obligated to obtain, and continue to maintain, $200 million of cost overrun insurance. The Senior Credit Facility was repaid in full and cancelled upon completion of the US$450 million Senior Secured Notes offering in April 2002.

l. On July 25, 2001, we completed an equity private placement to certain of our existing shareholders of 3,404,729 Non-voting Convertible Equity Shares at $13.00 and $14.00 per share, together with 725,589 Non-voting Convertible Equity Shares issued on a flow-through basis at $15.60 per share, for aggregate gross proceeds of $57.9 million. In conjunction with this offering, 2,589,641 Call Obligations were issued to certain subscribers, whereby each Call Obligation is exercisable into one Non-voting Convertible Equity Share and one Warrant to purchase Non-voting Convertible Equity Share upon the payment of $13.00 per Call Obligation. These call obligations are exercisable until March 31, 2003 at our discretion and the underlying warrant is exercisable, at the market price on the day we exercise our rights under the call obligations, for a period of four years after the call obligation exercise. There is a requirement imposed by the TSE to undertake a rights offering prior to exercising any of these Call Obligations. At this time, certain shareholders also undertook to subscribe for 725,590 Non-voting Convertible Equity Shares on a flow-through basis at $15.60 per share, which were subscribed for and issued in November 2001.

m. On October 25, 2001, we established a new $88 million two-year bridge note purchase facility ("Bridge Facility") with a Canadian Chartered Bank. The notes issuable pursuant to draws on the Bridge Facility are convertible, at maturity at our option, and in the event of a default at the option of the bank into Common Shares. This Bridge Facility replaced the existing $90 million and $30 million bridge facilities and was required in order to satisfy the sufficiency of funding criteria of the Senior Credit Facility, in order to demonstrate that we can meet our funding obligations to the Project. This Bridge Facility was fully drawn upon as at December 31, 2002.

n. On October 25, 2001, we completed a rights offering to existing shareholders of 3,384,835 Common Shares at a price of $14.00 per share for gross proceeds of $47.4 million.

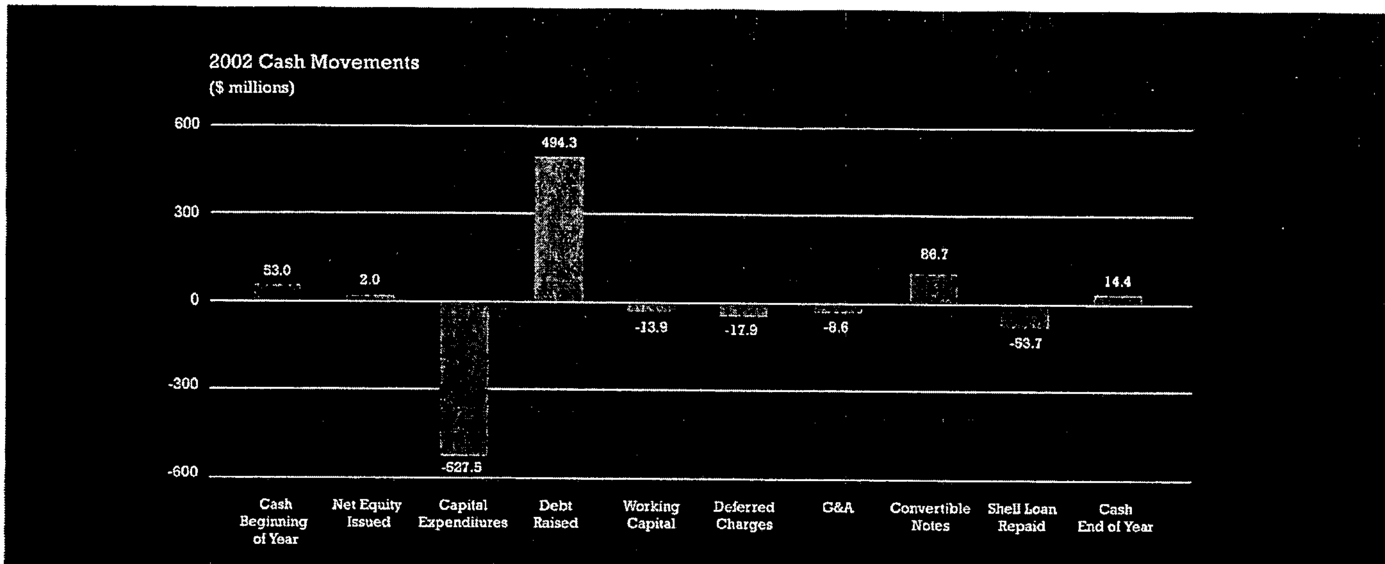
o. In November 2001, we completed a private placement of 150,000 Non-voting Convertible Equity Shares issued on a flow-through basis at $17.30 per share for gross proceeds of $2.6 million. At this time, the undertakings for 725,590 Non-voting Convertible Equity Shares on a flow-through basis from July were also subscribed to, for gross proceeds of $11.3 million. In addition to the new equity raised, another prospectus was filed on November 27, 2001, which qualified for issuance an aggregate of 5,005,908 Common Shares issuable upon conversion of all the Non-voting Convertible Equity Shares that were issued in 2001.

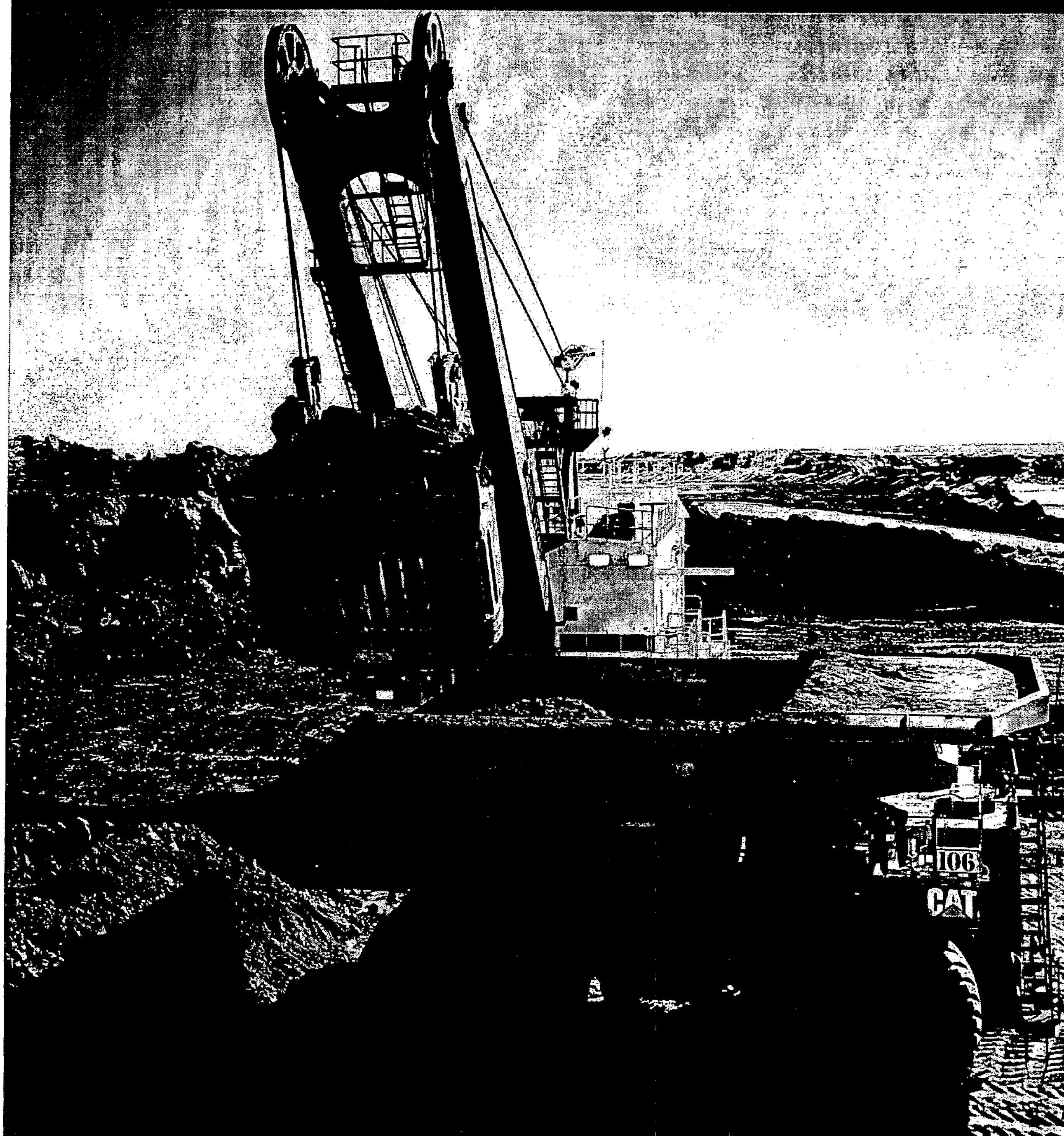
p. In April 2002, we completed the issuance of US$450 million of Senior Secured Notes, bearing interest fixed at 8.375%, and maturing on May 1, 2012 The net proceeds of the offering were used to repay all amounts outstanding under the existing Senior Credit Facility and repay all amounts due to Shell Canada Limited, with the balance of the proceeds placed in a trust account, which were used for funding the Company's share of remaining construction costs for the oil sands project. The Senior Credit Facility was cancelled upon repayment.

In conjunction with the offering, we established a new $100 million credit facility with a syndicate of chartered banks; $75 million of which will primarily be used to fund the first year's debt service under the offering as well as construction completion costs; the remaining $25 million is for working capital and letter of credit requirements. At December 31, 2002, $45.0 million had been drawn under this facility, with letters of credit also issued for $15.4 million.

q. In November 2002, we established a new $50 million Working Capital Facility with a syndicate of Canadian chartered banks, primarily to fund our working capital requirements during start-up of the Project. This facility was increased to $75 million in January 2003 with the addition of another bank to the syndicate.

r. Subsequent to year-end, we completed the issuance of 2,050,000 Common Shares at a price of $24.50 per share for gross proceeds of approximately $50.2 million. The Common Shares were offered to the public on a bought-deal basis through a syndicate of underwriters led by TD Securities Inc. Net proceeds from the issue will be used to fund remaining costs for the Project and related expenses, for general corporate purposes and may be used to reduce some of our short-term borrowings.


2002 Cash Movements
($ millions)
600
300
0
-300
-600
53.0
2.0
-527.5
494.3
-13.9
-17.9
-8.6
86.7
-53.7
14.4
Cash Beginning of Year
Net Equity Issued
Capital Expenditures
Debt Raised
Working Capital
Deferred Charges
G&A
Convertible Notes
Shell Loan Repaid
Cash End of Year



At December 31, 2002, our equity capital consisted of:

Issued and Outstanding:	
Common Shares	47,742,471
Class D Preferred Shares, Series A	666,667
	48,409,138
Outstanding:	
Class A Warrants	494,224
Stock Options	1,329,000
Fully diluted number of shares	50,232,362

Analysis of Cash Resources

We have been financing Project costs out of equity and debt proceeds throughout 2002. Our cash balances decreased by $38.6 million during 2002 from $53.0 million at December 31, 2001 to $14.4 million at December 31, 2002. Cash inflows were comprised of $494.3 million of long-term debt issued during the year (net of repayments), $86.7 million of convertible debt issued in the year (net of interest paid) and $2.0 million of equity capital (net of issue costs) raised throughout the year. Cash outflows included capital expenditures of $527.5 million, debt issue costs and deferred charges of $17.9 million, a $13.9 million increase in working capital throughout the year and cash corporate expenses of $8.6 million. In addition, we repaid a liability owed to Shell Canada Limited of $53.7 million.

Risk and Success Factors Relating to Oil Sands

We face a number of risks that we need to manage in conducting our business affairs. The following discussion identifies some of the key areas of exposure for us and, where applicable, sets forth measures undertaken to reduce or mitigate these exposures. A complete discussion of risk factors that may impact our business is provided in our Annual Information Form.

Business Risks

We are currently a single purpose company, our only asset being our investment in oil sands through the Project. As such, all capital expenditures are directly or indirectly related to oil sands construction and development and 100 per cent of revenues will be derived from oil sands operations.

At this stage, the main risks to the Project execution include the potential for reduced productivity and increased costs that can be associated with weather or unforeseen disruptions in the supply of labour. While the design of the Project facilities mainly utilizes established technologies, the commissioning and start-up of the new facilities could result in delays in achieving the targeted production capacity of 155,000 barrels per day by the third quarter of 2003.

We may be faced with competition from other industry participants in the oil sands business. This could take the form of competition for skilled people, increased demands on the Fort McMurray infrastructure (housing, roads, schools, etc.), or higher prices for the products and services required to operate and maintain the plant.

Our relationship with our employees and provincial building trade unions is important to our future success because poor productivity and work disruptions have the potential to adversely affect the Project, whether in construction or in operations. New labour agreements with the building trades were ratified in August 2001. While we are not a direct party to these agreements, they impact us as these trades have supplied the labour during the construction phase of the Project. Although we are now entering an operating phase we have significant plans for expansion and the strong working relationship the Project's management has developed with the trade unions will be an important factor in our future activities.

The Project depends upon successful operation of facilities owned and operated by third parties. The Joint Venture partners are party to certain agreements with third parties to provide for, among other things, the following services and utilities:

- pipeline transportation to be provided through the Corridor Pipeline;
- electricity and steam to be provided to the Mine and the extraction plant from the Muskeg River cogeneration facility;
- transportation of natural gas to the Muskeg River cogeneration facility by the ATCO pipeline;
- hydrogen to be provided to the Upgrader from the HMU and Dow Chemicals Canada Inc., or Dow; and
- electricity and steam to be provided to the Upgrader from the Upgrader cogeneration facility.

All of these third party arrangements are critical for the successful start-up and operation of the Project. Disruptions in respect of these facilities could have an adverse impact on future financial results.

Once the Project is operational, we will be subject to the operational risks inherent in the oil sands business. We intend to sell our share of synthetic crude oil production to refineries in North America. These sales will compete with the sales of both synthetic and conventional crude oil. There exist other suppliers of synthetic crude oil and there are several additional projects being contemplated. If undertaken and completed, these projects will result in a significant increase in the supply of synthetic crude oil to the market. In addition, not all refineries are able to process or refine synthetic crude oil. There can be no assurance that sufficient market demand will exist at all times to absorb our share of the Project's light synthetic crude oil production.

As a partner in the Athabasca Oil Sands Joint Venture, we actively participate in operational risk management programs implemented by the Joint Venture to mitigate the above risks. Our exposure to operational risks is also managed by maintaining appropriate levels of insurance.

Financial Risks

We must finance our share of the construction costs of the Project in the face of uncertain debt and equity capital markets and in a volatile commodity-pricing environment. Should the costs of the Project exceed the available financial resources and we are unable to establish sufficient funding to complete the Project under the current debt arrangements, additional financing may be required.

On the basis of the current estimate of costs for construction of the Project, we have funding arrangements that are sufficient to cover our share of costs. An increase in the costs for completion of the Project beyond the current estimate may result in us raising additional equity or debt in order to meet our share of cost commitments.

As part of our financing plan, we established a cost overrun/project delay insurance policy in the amount of $200 million. This insurance policy covers certain costs, expenses and losses of revenue through the construction period arising from causes beyond our control and including: (i) costs and expenses or loss of revenues arising from a delay in achieving a guaranteed production level; (ii) costs and expenses incurred in connection with the modification, repair or replacement of equipment or material, which are directly related to achieving guaranteed production levels; and (iii) escalation in Project costs beyond the budgeted Project costs, which are directly related to achieving guaranteed production levels. In effect, the program provides coverage for increased costs for the project of up to $200 million to the extent the increased costs are incurred to meet bitumen production levels of 155,000 barrels per day as contemplated in the initial design of the project.

This insurance policy will mitigate a portion of the cost increases for the project beyond the initial project budget of $709 million (our share). We engaged claims consultants in the first quarter of 2002, and by year-end we had filed interim claims for cost overruns totalling $435 million and interim claims for loss of revenues arising from delays in production totalling $9.3 million. The forecasted total claim for loss of revenues, to be submitted prior to achieving commercial production in the second quarter of 2003, is expected to be in excess of $100 million. To date, we have not received any proceeds from the insurance policy and no amounts have been reflected in the Consolidated Financial Statements. We have been frustrated by the lack of response on the part of the insurers and in January 2003 we were forced to raise $50.2 million of additional equity financing as a direct result of these delays. While we hope that insurance proceeds will be forthcoming, further delays may put additional pressure on our financial condition.

In addition to the cost overrun insurance obtained by us, the Joint Venture partners have obtained insurance to protect against certain risks of loss during the construction of the Owners' facilities, which includes the Mine, extraction plant and the Upgrader. The insurance is typical for a project of this nature.

Upon commencement of operations, we intend to obtain insurance designed to protect our ownership interest against losses or damage to the Owners' facilities, to preserve our operating income and to protect against our risk of loss to third parties and which is reasonably obtainable.

Once in production, our financial results will be dependent upon the prevailing price of crude oil. Oil prices fluctuate significantly in response to supply and demand factors beyond our control, which could have an impact on future financial results.

As at December 31, 2002 we have entered into various commodity pricing agreements designed to mitigate exposure to the volatility of crude oil prices in Canadian dollars. The agreements are summarized as follows:

	Notional Volume	Hedge Period	Price Received	Unrealized Gain/(Loss)
WTI Swaps	4,500 bbls/d	April 1, 2003 to March 31, 2004	Cdn$39.72	($1.1 million)
WTI Swaps	8,500 bbls/d	April 1, 2004 to March 31, 2005	Cdn$36.95	($1.5 million)

We do not expect that the adoption of the new CICA Accounting Guideline 13 "Hedging Relationships", effective for fiscal years beginning on or after July 1, 2003, will have an impact on our consolidated financial statements.

Any prolonged period of low oil prices could result in a decision by the Joint Venture partners to suspend or reduce production. Any such suspension or reduction of production would result in a corresponding substantial decrease in our future revenues and earnings and could expose us to significant additional expense as a result of certain long-term contracts. In addition, because natural gas comprises a substantial part of operating costs, any prolonged period of high natural gas prices could negatively impact our future financial results.

We will also be exposed to fluctuations in changes in currency and interest rates, which may impact our financial results and our ability to service our debt financing.

To mitigate our exposure to these financial risks, we will be establishing a financial risk management program in consultation with our Board of Directors prior to commencement of operations.

Environmental Risks

Canada is a signatory to the December 1997 Kyoto Treaty with respect to instituting reductions to greenhouse gases. The Project will be a significant producer of some greenhouse gases covered by the treaty. While specific measures for meeting Canada's commitments have not been developed and the Kyoto treaty may be modified or nullified, actions taken under the treaty may adversely impact the Project. It cannot be assured that future environmental approvals, laws or regulations will not adversely impact the Joint Venture partners' ability to operate the Project or increase or maintain production or will not increase unit costs of production. Equipment from suppliers that can meet future emission standards may not be available on an economic basis, or at all, and other methods of reducing emissions to required levels may significantly increase operating costs or reduce output. There is a risk that the Canadian federal and/or provincial governments could pass legislation that would tax such emissions or require, directly or indirectly, reductions in such emissions produced by energy industry participants, including the Project.

We will be responsible for compliance with terms and conditions set forth in the Project's environmental and regulatory approvals and all laws and regulations regarding the decommissioning and abandonment of the Project and reclamation of its lands. The costs related to these activities may be substantially higher than anticipated. It is not possible to accurately predict these costs since they will be a function of regulatory requirements at the time and the value of the equipment salvaged. In addition, to the extent we do not meet the minimum credit rating required under the Joint Venture agreement, we must establish and fund a reclamation trust fund. We currently do not hold the minimum credit rating. Even if we do hold the minimum credit rating, in the future it may be determined that it is prudent or be required by applicable laws or regulations to establish and fund one or more additional funds to provide for payment of future decommissioning, abandonment and reclamation costs. Even if we conclude that the establishment of such a fund is prudent or required, we may lack the financial resources to do so.

The Joint Venture partners have established programs to monitor and report on environmental performance including reportable incidents, spills and compliance issues. In addition, comprehensive quarterly reports are prepared covering all aspects of health, safety and sustainable development on Lease 13 and the Upgrader to ensure that the Project is in compliance with all laws and regulations and that management are accountable for performance set by the Joint Venture partners.

Outlook

Key milestones for 2003 include revenues from production of synthetic crude expected to commence in the first quarter of 2003 when the Upgrader facilities will be brought on stream and production will ramp-up through the second half of 2003. Full bitumen production of 155,000 barrels per day (31,000 barrels per day net to us) is scheduled to occur by the third quarter of 2003.

Non-bitumen feedstocks supplied to the Upgrader to aid in the upgrading process will add an additional 35,000 barrels per day to the Project's output. Our share of total output will be 38,000 barrels per day. We are committed to sell 12,000 barrels per day of Vacuum Gas Oil (VGO) to Shell at a fixed differential to market. We will be marketing the balance of our production volumes for our own account to various refineries in North America.

The following table details the sensitivities of cash flow and net earnings per share to certain relevant operating factors during 2004, which will be our first year of full production. The base case upon which the sensitivities are reflected assumes bitumen production for us of 31,000 barrels per day, constant WTI at US$22.00 per barrel, a foreign exchange rate of US$0.65 per Cdn$, a constant Alberta gas cost of Cdn$4.51 per thousand cubic feet and reflects the additional shares issued in the February 2003 equity offering.

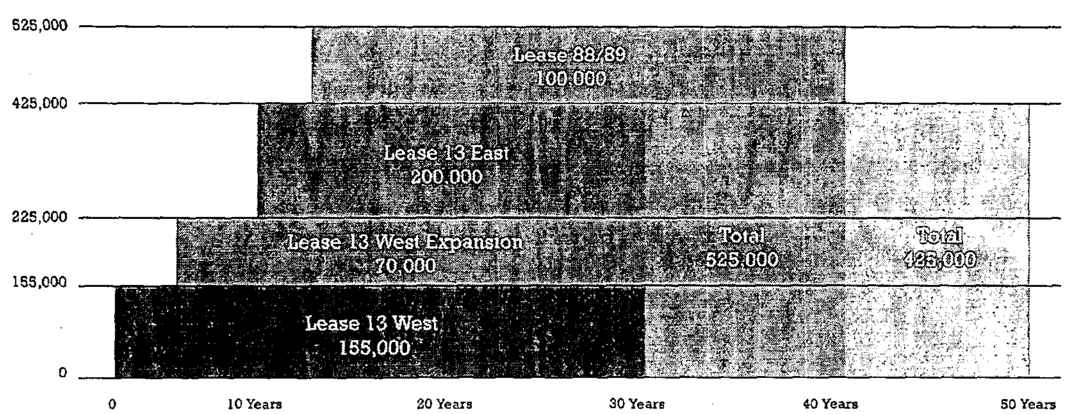
Variable	Variation	Cash Flow ($millions)	Basic Cash Flow Per Share	Earnings ($millions)	Basic Earnings Per Share
Production	1,000 bbls/day	$ 12.17	$ 0.24	$ 7.60	$ 0.15
Oil Prices	USD $1.00	$ 17.23	$ 0.34	$ 11.03	$ 0.22
Gas Prices	$0.10/Mcf	$ 0.71	$ 0.01	$ 0.46	$ 0.01
Foreign Exchange [1]	USD/CDN .01	$ 5.62	$ 0.11	$ 3.60	$ 0.07

[1] Excludes unrealized foreign exchange gains or losses on long-term monetary items. The impact of the Canadian dollar strengthening by US $0.01 would be an increase of $10.5 million in net earnings based on December 31, 2002 US dollar donominated debt levels.

Our vision is to complete this Project and then expand our production base through development of the remaining oil sands leases we have access to under the Joint Venture agreement with our partners. The initial Project will develop a total of 1.7 billion barrels (336 million barrels is our share) out of a total resource base on Leases 13, 88, 89 and 90 estimated at 8.8 billion barrels (1.8 billion barrels is our share). Our partners or we have not yet begun development of the remaining resources on our leases, but we have begun evaluating long-term development plans. Any such development plans would be subject to approval by the board of directors of each Joint Venture partner, various regulatory agencies and other stakeholders, and would require significant funding obligations.

The potential development plans include two areas of expansion. Firstly, an optimization and expansion of the Muskeg River Mine and Lease 90 has the potential to increase bitumen production to 225,000 barrels per day (45,000 barrels per day net to us) and would likely take place in the 2006 to 2007 time frame. Secondly, there is an opportunity for a new stand-alone mine on the eastern portion of Lease 13 and Leases 88 and 89, known as the Jackpine Mine, which would add a potential 300,000 barrels per day (60,000 barrels per day net to us) of bitumen production. The Jackpine Mine development would follow the expansion of the Muskeg River Mine. The Joint Venture Owners filed a Public Disclosure Document in respect of these development opportunities on August 8, 2001. The graph below outlines the potential effect on bitumen production per day assuming the development plans are undertaken successfully.

Development Potential
(barrels per day)



Management's Report

The accompanying consolidated financial statements and all information in the annual report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies described in the notes to the consolidated financial statements. In the opinion of management, the consolidated financial statements have been prepared within acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles appropriate in the circumstances. The financial information contained elsewhere in the annual report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management has developed and maintains systems of internal accounting controls, policies and procedures in order to provide reasonable assurance as to the reliability of the financial records and the safeguard of assets.

External auditors, appointed by the shareholders of the Company, have examined the consolidated financial statements and have expressed an opinion on the statements. Their report is included with the consolidated financial statements.

The Board of Directors of the Company has established an Audit Committee, consisting of non-management directors, to review these statements with management and the auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

Guy J. Turcotte
President and Chief Executive Officer
Calgary, Canada
February 14, 2003

David A. Dyck
Vice President, Finance and Chief Financial Officer

Auditors' Report

To The Shareholders of Western Oil Sands Inc.

We have audited the consolidated balance sheets of Western Oil Sands Inc. as at December 31, 2002 and 2001 and the consolidated statements of operations and deficit, and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Western Oil Sands Inc. as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Canada
February 14, 2003

Consolidated Balance Sheets

December 31 ($ thousands)	2002	2001
Assets		
Current Assets		
Cash	$ 14,428	$ 52,973
Accounts receivable	6,624	7,228
Inventory	4,175	–
	25,227	60,201
Capital Assets (Note 3)	1,306,989	761,939
Deferred Charges (Note 4)	27,422	32,254
	1,334,411	794,193
	$ 1,359,638	$ 854,394
Liabilities		
Current Liabilities		
Accounts payable and accrued liabilities	$ 40,953	$ 51,222
Convertible Notes (Note 5)	4,055	–
	45,008	51,222
Long-term Liabilities		
Long-term Debt (Note 6)	775,820	279,481
Other (Note 8)	50,859	88,825
Future Income Taxes (Note 7)	454	–
	827,133	368,306
	872,141	419,528
Shareholders' Equity		
Share Capital (Note 9)	426,275	447,303
Convertible Notes (Note 5)	83,945	–
Deficit	(22,723)	(12,437)
	487,497	434,866
	$ 1,359,638	$ 854,394

See accompanying Notes to the Consolidated Financial Statements

Approved by the Board of Directors:

Robert G. Puchniak
DIRECTOR

Brian F. MacNeill
DIRECTOR

Consolidated Statements of Operations and Deficit

Year ended December 31 ($ thousands, except amounts per share)	2002	2001
Corporate Expenses		
General and administrative	$ 5,698	$ 5,310
Depreciation	192	170
Write-off of deferred financing costs	22,759	–
Loss before Income Taxes	28,649	5,480
Income Taxes (Note 7)	(19,646)	1,535
Net Loss	$ 9,003	$ 7,015
Charge for Convertible Notes (Note 5)	1,283	–
Loss Attributable to Common Shareholders	10,286	7,015
Deficit at Beginning of Year	12,437	5,422
Deficit at End of Year	$ 22,723	$ 12,437
Loss per share (Note 9) – Basic and diluted	$ 0.21	$ 0.17

See accompanying Notes to the Consolidated Financial Statements

Consolidated Statements of Cash Flows

Year ended December 31 ($ thousands)	2002	2001
Cash provided by (used in)		
Operating Activities		
Net loss	$ (9,003)	$ (7,015)
Non-cash items:		
Write-off of deferred financing costs	22,759	–
Future Income Tax recovery	(22,551)	–
Depreciation	192	170
Cash from Operations	(8,603)	(6,845)
Increase in non-cash working capital (Note 14)	(7,965)	–
	(16,568)	(6,845)
Financing Activities		
Issue of share capital	1,977	143,978
Issue of long-term debt	773,840	279,481
Repayment of long-term debt	(279,481)	–
Deferred financing costs	(17,927)	(16,366)
Issue of convertible notes	88,000	–
Charge for convertible notes	(1,283)	–
Repayment of long-term liabilities	(53,687)	(2,152)
Cash Generated	511,439	404,941
Investing Activities		
Capital expenditures	(527,541)	(433,604)
Restricted cash	–	12,601
Increase in non-cash working capital (Note 14)	(5,875)	(18,231)
Cash Invested	(533,416)	(439,234)
Decrease in Cash	(38,545)	(41,138)
Cash at Beginning of Year	52,973	94,111
Cash at End of Year	$ 14,428	$ 52,973

See accompanying Notes to the Consolidated Financial Statements

Notes to the Consolidated Financial Statements

(Tabular dollar amounts in $ thousands)

1. Business of the Corporation

Western Oil Sands Inc. (the "Corporation") was incorporated on June 18, 1999 under the laws of the Province of Alberta. The Corporation was created to acquire a 20 per cent working interest in an oil sands project in the Athabasca region of northeast Alberta ("the Oil Sands Project"). The oil sands project will consist of direct or indirect participation in the design, construction and operation of mining, extracting, transporting and upgrading of oil sands deposits.

2. Summary of Accounting Policies

(a) Principles of Consolidation

The consolidated financial statements include the accounts of the Corporation and its wholly-owned subsidiary corporations and limited partnership, 852006 Alberta Limited, Western Oil Sands, L.P., Western Oil Sands Finance Inc. (inactive) and Western Oil Sands (USA) Inc. (inactive). The Corporation's oil sands activities are conducted jointly with others. These financial statements reflect only the Corporation's proportionate interest in such activities.

(b) Measurement Uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period.

(c) Capital Assets

Capital assets are recorded at cost less accumulated provisions for depreciation, depletion and amortization. Capitalized costs include costs specifically related to the acquisition, exploration, development and construction of the oil sands project. Capital assets are reviewed for impairment whenever events or conditions indicate that their net carrying amount may not be recoverable from estimated future cash flows.

Depletion over the life of proved and probable reserves is on a unit of production basis, commencing when the facilities are substantially complete and after commercial production has begun. Capital assets are depreciated on a straight-line basis over their useful lives, except for lease acquisition costs and certain mine assets, which are amortized and depreciated over the life of proved and probable reserves. The estimated useful lives of depreciable capital assets are as follows:

Leasehold improvements	5 years
Furniture and fixtures	5 years
Computers	3 years

(d) Future Site Restoration

Estimated future site restoration and reclamation costs are provided on a unit of production method based on estimated proved and probable reserves. Actual costs are charged against the provision when incurred.

(e) Foreign Currency Translation

Transactions in foreign currencies are translated into Canadian dollars at exchange rates prevailing at the transaction dates. Monetary assets and liabilities denominated in a foreign currency are translated into Canadian dollars at rates of exchange in effect at the end of the period while non-monetary assets and liabilities are translated at historical rates of exchange.

(f) Stock-based Compensation Plan

The Corporation has a stock-based compensation plan which is described in Note 10. Effective January 1, 2002, the Corporation adopted CICA 3870 "Stock-based Compensation and Other Stock-based Payments". The new standard is applied prospectively to all stock-based payments to non-employees and to employee awards that are direct awards of stock, stock appreciation rights and similar awards to be settled in cash. The new standard is applied to all grants of stock options on or after January 1, 2002. No compensation expense is recognized for the plan when the stock options are issued. Any consideration received on exercise of stock options is credited to share capital.

(g) Convertible Notes

Amounts drawn under the Note Purchase Facility are deemed to consist of both an equity and a liability component in accordance with Canadian GAAP. The initial carrying amount of the equity component is adjusted for accretion to bring it up to the stated principal amount of the Note Purchase Facility at maturity. This accretion is charged to the Deficit.

(h) Derivative Financial Instruments

Financial instruments are used by the Corporation to hedge its exposure to market risks relating to commodity prices and foreign currency exchange rates. The Corporation's policy is not to utilize financial instruments for speculative purposes.

The Corporation formally documents all relationships between hedging instruments and hedged items as well as its risk management objectives and strategies for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Corporation also assesses, both at the hedges' inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

The Corporation enters into hedges with respect to a portion of its oil production to achieve a more predictable cash flow by reducing its exposure to price and currency fluctuations. These transactions are entered into with major Canadian financial institutions. Gains and losses from these financial instruments are recognized in oil revenues as the hedge sale transactions occur.

(i) Inventory

Inventory is stated at the lower of average cost and net realizable value.

(j) Loss per Share

The Corporation uses the treasury stock method to determine the dilutive effects of stock options and other dilutive instruments. Due to losses for the years presented, all incremental shares have been excluded from the diluted earnings per share calculation as the effect would be anti-dilutive.

(k) Cash

Cash presented in the consolidated financial statements is comprised of cash and cash equivalents and includes short-term investments with a maturity of three months or less when purchased.

(l) Pension Plan

The Corporation has a defined contribution pension plan. Expense is recognized as payments are made or entitlements are earned. Expense for the year ended December 31, 2002 was $0.09 million (December 31, 2001 – $0.2 million).

(m) Comparative amounts

Certain comparative amounts have been reclassified to conform to the current year's presentation.

3. Capital Assets

	2002	2001
Oil Sands Project	$ 1,243,061	$ 721,043
Oil Sands Project assets under capital lease	50,859	35,138
Corporate Assets	13,601	6,098
	1,307,521	762,279
Less: accumulated depreciation	(532)	(340)
	$ 1,306,989	$ 761,939

It is the Corporation's policy to capitalize carrying costs including interest expense for capital assets acquired, constructed or developed over time. As at December 31, 2002, $63.6 million of net interest expense (December 31, 2001 – $15.5 million) has been capitalized as part of the cost of the oil sands project. Cash interest paid for the year ended December 31, 2002 was $40.6 million (December 31, 2001 – $6.7 million). Cash interest received for the year ended December 31, 2002 was $2.3 million (December 31, 2001 – $2.9 million).

4. Deferred Charges

	2002	2001
Deferred charges	$ 27,422	$ 32,254

Deferred charges include primarily debt financing costs that have been incurred in establishing the Corporation's various debt facilities. These amounts will be amortized over the term of the related debt facilities following start-up of the oil sands project.

5. Convertible Notes

On October 25, 2001 the Corporation established an $88 million two-year Note Purchase Facility (the "Note Purchase Facility") with a Canadian chartered bank. The notes issuable pursuant to draws on the Note Purchase Facility are convertible, at maturity at the option of the Corporation and in the event of a default at the option of the bank, into Common Shares of the Corporation. If converted, the conversion would be transacted at 95 per cent of the weighted average trading price on the TSX for the twenty days prior to conversion. The maturity date is October 25, 2003. Borrowings under the Note Purchase Facility bear interest at the bank's prime lending, the bankers' acceptance or the LIBOR rates plus applicable margins ranging from 125 to 225 basis points. The Note Purchase Facility is unsecured and was fully drawn at December 31, 2002.

6. Long-term Debt

	2002	2001
US$450 million Senior Secured Notes	$ 710,820	–
Bank Debt	$ 65,000	$ 279,481
	$ 775,820	$ 279,481

(a) On April 23, 2002, the Corporation issued Senior Secured Notes in the amount of US$450 million, bearing interest at 8.375 per cent, with a maturity of May 1, 2012 (the "Offering"). The net proceeds of the Offering were used to repay all amounts outstanding under the Corporation's $535 million bank facility (which was cancelled upon repayment) and repay all amounts due to Shell Canada Limited, with the balance of the proceeds used to fund the Corporation's share of remaining construction costs for the oil sands project. The Senior Secured Notes provide the holders with security over all the assets of the Corporation, subordinated to the Senior Credit Facility, until the Corporation achieves an investment grade corporate credit rating, at which time the Senior Secured Notes become unsecured.

(b) In conjunction with the Offering, the Corporation established a new $100 million Senior Credit Facility (the "Senior Credit Facility") with a syndicate of Canadian chartered banks, up to $75 million of which will be used to fund the first year's debt service under the Offering and construction completion costs; the remaining $25 million will be used for working capital and letter of credit requirements. Borrowings under the facility bear interest at the lenders' prime lending, the bankers' acceptance or the LIBOR rates plus applicable margins ranging from 100 to 200 basis points. $75 million of the Senior Credit Facility matures and is repayable by April 23, 2005. The Senior Credit Facility contains certain covenants and other provisions, which restrict the Corporation's ability to incur additional indebtedness, pay dividends or make distributions of any kind, undertake an expansion of the oil sands project, dispose of its interest in the oil sands project, or change the nature of its business. The Senior Credit Facility provides the banks with security over all of the assets of the Corporation, with the exception of certain intercompany notes and note guarantees issued in connection with the Offering detailed in Note 6(a). At December 31, 2002, an amount of $45 million had been drawn under this Senior Credit Facility and letters of credit for $15.4 million had been issued.

(c) On November 19, 2002, the Corporation established a $50 million 364-day Extendible Revolving Credit Facility (the "Revolving Facility") with a syndicate of Canadian chartered banks. Borrowings under the Revolving Facility bear interest at the lenders' prime lending, the bankers' acceptance or the LIBOR rates plus applicable margins ranging from 100 to 200 basis points. The Revolving Facility provides the banks with security over all of the assets of the Corporation, with the exception of certain intercompany notes and note guarantees in connection with the Offering detailed in Note 6(a). The Revolving Facility contains a two-year term-out provision should the facility not be renewed. At December 31, 2002, an amount of $20 million had been drawn under this facility.

(d) The Corporation defers all issue costs and charges relating to the Corporation's existing debt facilities prior to commencement of commercial operations, and will amortize the charges thereafter. Upon completion of the Offering, $22.8 million of such costs (representing amounts not related to continuing debt facilities) were written off.

7. Income Taxes

	2002	2001
Large Corporations Tax	$ 2,905	$ 1,535
Future Income Tax	(22,551)	–
Income tax (recovery) expense	$ (19,646)	$ 1,535

Cash taxes paid during the year ended December 31, 2002 were $2.4 million (December 31, 2001 – $1 million) and related solely to Large Corporations Tax.

At December 31, 2002, the future income tax liability consists of:

	2002	2001
Future Income Tax assets		
Net losses carried forward	$ 19,069	$ 11,584
Share issue costs	2,096	3,191
Debt issue costs	1,386	–
Future Income Tax liabilities		
Renunciation of deductions for flow-through shares	(23,005)	–
Debt issue costs	–	(4,132)
Less: valuation allowance	–	(10,643)
Net future income tax liability	$ (454)	$ –

The following table reconciles income taxes calculated at the Canadian statutory rate of 42.12% (2001 – 42.62%) with actual income taxes:

	2002	2001
Loss before income taxes	$ (28,649)	$ (5,480)
Income tax recovery at statutory rate	(12,067)	(2,336)
Unrecognized benefit of losses	–	2,336
Recognition of losses brought forward	(10,484)	–
Large Corporations Tax	2,905	1,535
Income tax (recovery) expense	$ (19,646)	$ 1,535

The tax loss carry forward balances as evaluated at December 31, 2002 and the expiry dates are as follows:

Year Created	Amount	Expiry
1999	$ 1.2 million	2006
2000	$ 11.7 million	2007
2001	$ 8.8 million	2008
2002	$ 23.6 million	2009

In addition, at December 31, 2002, the Corporation had approximately $1.1 billion of tax pools available.

8. Other Long-term Liabilities

	2002	2001
Capital lease obligation	$ 50,859	$ 35,138
Payable to Shell Canada Limited	–	53,687
	$ 50,859	$ 88,825

The capital lease obligation relates to the Corporation's share of capital costs for the hydrogen-manufacturing unit within the oil sands project. Repayment of the principal obligation is scheduled to be $0.7 million in 2003 and $1.3 million per annum thereafter until fully repaid.

The Corporation was obligated to pay $40 million to acquire an interest in the lease and to compensate the vendor of the interest for the benefit of existing infrastructure at the Upgrader site. The Corporation elected to defer payment of the $40 million by paying an annual deferral charge which includes interest plus an adjustment for income taxes, until the Corporation issued the Senior Secured Notes, part of the proceeds of which were used to repay all amounts due to Shell Canada Limited.

9. Share Capital

(a) Authorized

The Corporation is authorized to issue an unlimited number of Class A shares ("Common Shares"), an unlimited number of non-voting Convertible Class B Equity Shares ("Class B Shares"), an unlimited number of non-voting Class C Preferred Shares and an unlimited number of Class D Preferred Shares, issuable in series.

The Common Shares are without nominal or par value. The Class B Shares are convertible into Common Shares upon successful completion of a public offering or certain other events, but with no additional consideration owing to the Corporation. There have been no Class C Preferred Shares issued. The Class D Preferred Shares, Series A, which have been issued, are convertible into Common Shares prior to redemption on a one for one basis.

(b) Issued and Outstanding

Common Shares	Number of Shares		Amount
Balance at December 31, 2000	4,000,011	$	56,460
Issued on conversion of:			
Class B Shares	37,935,280		315,656
Class A Special Warrants	279,950		912
Class B Special Warrants	823,707		2,059
Issued on exercise of Class B Warrants	465,188		3,721
Issued for cash [1]	625,000		10,000
Issued upon rights offering	3,384,835		47,388
Share issue Costs			(856)
Balance at December 31, 2001	47,513,971	$	435,340
Issued for cash	228,500		1,977
Renunciation of flow-through shares [4]	–		(23,005)
Balance at December 31, 2002	47,742,471		414,312
Class B Shares			
Balance at December 31, 2000 [2]	32,929,372	$	243,895
Issued for cash [3]	5,005,908		71,761
Converted to Common Shares	(37,935,280)		(315,656)
Balance at December 31, 2001 and December 31, 2002	–	$	–
Class A Special Warrants			
Balance at December 31, 2000	279,950	$	912
Converted to Common Shares	(279,950)		(912)
Balance at December 31, 2001 and December 31, 2002	–	$	–
Class B Special Warrants			
Balance at December 31, 2000	823,707	$	2,059
Converted to Common Shares	(823,707)		(2,059)
Balance at December 31, 2001 and December 31, 2002	–	$	–
Class D Preferred Shares			
Balance at December 31, 2000	–	$	–
Issued for cash	666,667		12,000
Share issue costs			(37)
Balance at December 31, 2001 and December 31, 2002	666,667	$	11,963
Total Share Capital	48,409,138	$	426,275

1 Includes 625,000 shares issued by the Corporation on a flow-through basis.

2 Includes 1,491,084 shares issued by the Corporation on a flow-through basis.

3 Includes 1,601,179 shares issued by the Corporation on a flow-through basis.

4 In accordance with certain provisions of the Income Tax Act, Canadian exploration expenses or Canadian development expenses related to expenditures of the subscribed funds for shares issued on a flow-through basis are transferred to the shareholders. Effective December 31, 2002, all the expenditures related to these shares had been renounced and the tax deductions were transferred to the shareholders. Accordingly, a future income tax liability is created and share capital is reduced by the tax effect of the renounced expenditures.

(c) Loss Per Share

In calculating the weighted average number of Common Shares outstanding, the Corporation includes Common Shares, Class B Shares, Class A Special Warrants, and Class B Special Warrants. The Class B Shares have been included as they are entitled to dividends in parity with the Common Shares. On February 1, 2001 the Corporation qualified for distribution the Common Shares issuable on conversion or exercise of the Class B Shares and the Class A and B Special Warrants. Weighted average number of Common Shares outstanding for December 31, 2002 is 48,330,320 (December 31, 2001– 41,404,904).

(d) Class D Preferred Shares

On March 14, 2001, the Corporation completed a private placement for the issuance of 666,667 Class D Preferred Shares, Series A, for proceeds of $12 million. The Class D Preferred Shares, Series A, can be converted into Common Shares prior to redemption on a one for one basis. If not previously converted, they are redeemable at the option of the Corporation at any time at a price equal to their issue price, plus a cumulative dividend of 12 per cent per year compounded semi-annually until January 1, 2007, from which date the dividend increases by 3 per cent per quarter to a maximum of 24 per cent per year. Cash dividends are not paid on the Class D Preferred Shares.

(e) Call Obligations

The Corporation has entered into call obligation agreements with certain shareholders, which obligate the holders of the obligations to purchase up to 3,040,000 Class B Shares for $5.00 per share. The Corporation is entitled to require the subscriber to exercise their call obligations at its discretion upon the satisfaction of certain conditions. These call obligations were to expire on December 31, 2001, but were extended until March 31, 2003. An additional 2,589,641 call obligations were entered into in July 2001, whereby each call obligation is exercisable into one Class B Share and one warrant to purchase a Class B Share upon the payment of $13.00 per call obligation. These call obligations are exercisable until March 31, 2003 at the Corporation's discretion and the underlying warrant is exercisable at the then market price for a period of four years after the call obligation exercise. There is a requirement imposed by the TSX to undertake a rights offering prior to exercising any of the call obligations entered into in July 2001.

(f) Warrants

Effective February 1, 2001 the Corporation qualified for distribution 34,033,029 Common Shares, 494,224 Class A Warrants and 465,188 Class B Warrants resulting from the conversion of 32,929,372 Class B Shares; 279,950 Class A Special Warrants; and 823,707 Class B Special Warrants. In the first quarter of 2001, all Warrant Options and the 465,188 Class B Warrants were exercised. Consequently, the Corporation issued 465,188 Common Shares and received proceeds of $3.7 million. Each Class A Warrant entitles the holder to purchase one Common Share at $2.50 per share until five years after start-up of the oil sands project.

(g) Issuances

On July 25, 2001, the Corporation completed a private placement to certain of its existing shareholders for the issuance of 4,130,318 Class B Shares, of which 725,589 were issued on a flow-through basis, for aggregate proceeds of $57.9 million. Certain shareholders also undertook to subscribe for 725,590 Class B Shares on a flow-through basis that were issued on November 1, 2001 for proceeds of $11.3 million. In addition, the Corporation issued a further 150,000 Class B shares on a flow-through basis on November 1, 2001 at a price of $17.30 per share, for gross proceeds of $2.6 million. All 5,005,908 Class B Shares issued during 2001 were converted into Common Shares on November 27, 2001 upon qualification by prospectus, for no additional proceeds.

On October 25, 2001 the Corporation completed a Rights Offering, whereby rights to subscribe for 3,384,835 Common Shares at a price of $14.00 per share were offered to the holders of Common Shares and Class B Shares, for aggregate proceeds of $47.4 million.

10. Stock Options

(a) Stock Option Plan

The Corporation has established a Stock Option Plan for the issuance of options to purchase Common Shares to directors, officers and employees of the Corporation and its subsidiaries and persons providing ongoing services to the Corporation and its subsidiaries. Options granted under the Stock Option Plan generally vest on an annual basis over four years. The stock options expire five years from each vesting date.

	2002			2001		
	Number of Options		Weighted Average Exercise Price	Number of Options		Weighted Average Exercise Price
	(thousands)			(thousands)		
Outstanding at beginning of year	1,238	$	9.52	1,077	$	8.53
Granted	429		23.91	201		14.61
Exercised	(229)		8.64	–		–
Cancelled	(109)		8.50	(40)		8.50
Outstanding at end of year	1,329	$	14.40	1,238	$	9.52
Exercisable at end of year	550	$	9.02	526	$	8.53

The following table summarizes Stock Options outstanding and exercisable under the Stock Option Plan at December 31, 2002:

	Options Outstanding				Options Exercisable		
Exercise Price	Number of Options	Weighted Average Remaining Life		Weighted Average Exercise Price	Number of Options		Weighted Average Exercise Price
	(thousands)	(months)			(thousands)		
$8.50 – $12.00	704	54.2	$	8.55	505	$	8.53
$12.01 – $16.00	196	74.0		14.64	45		14.66
$20.01 – $24.00	411	81.1		23.85	–		–
$24.01 – $28.00	18	76.3		25.43	–		–
	1,329	65.8	$	14.40	550	$	9.02

The number of Common Shares reserved for issuance under the Stock Option Plan was 3,000,000 at December 31, 2002 (3,000,000 at December 31, 2001).

(b) Stock-Based Compensation

No compensation expense has been recognized when stock options are granted, in accordance with Note 1(f). Had compensation expense been determined based on the fair value method for awards made after December 31, 2001, the Company's net income and earnings per share would have been adjusted to the proforma amounts indicated below:

		Year Ended December 31, 2002
Net loss for the year – as reported	$	9,003
Net loss for the year – proforma	$	9,706
Basic loss per share – as reported	$	0.21
Basic loss per share – proforma	$	0.23

The proforma amounts exclude the effect of stock options granted prior to January 1, 2002. The weighted average fair value of the 429,000 options granted during the year was $8.39 using the Black-Scholes option pricing model. The following table sets out the assumptions used in applying the Black-Scholes model:

	Year Ended December 31, 2002
Risk free interest rate, average for year	4.55%
Expected life (in years)	5.00
Expected volatility	0.30
Dividend per share	–

11. Shareholders Rights Plan

The Corporation has a shareholders' rights plan (the "Plan"). Under the Plan, one right will be issued with each Common Share issued. The rights remain attached to the Common Share and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 per cent or more of the Common Shares of the Corporation, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase Common Shares of the Corporation at a 50 per cent discount from the then market price. The rights are not triggered by a "Permitted Bid", as defined in the Plan.

12. Financial Instruments and Risk Management

The Corporation's financial instruments that are included in the Consolidated Balance Sheets are comprised of cash, temporary investments, accounts receivable, all current liabilities and long-term borrowings and the Convertible Notes.

(a) Commodity Price Risk

The Corporation has entered into various commodity pricing agreements designed to mitigate the exposure to the volatility of crude oil prices in Canadian dollars. The agreements are summarized as follows:

	Notional Volume	Hedge Period	Price Received	Unrealized Gain/(Loss)
WTI Swaps	4,500 bbls/d	April 1, 2003 to March 31, 2004	Cdn$39.72	($1.1 million)
WTI Swaps	8,500 bbls/d	April 1, 2004 to March 31, 2005	Cdn$36.95	($1.5 million)

(b) Credit Risk

A substantial portion of the Corporation's accounts receivable relates to recoverable Goods & Services Tax. All crude oil swap agreements are with major financial institutions in Canada.

(c) Interest Rate Risk

At December 31, 2002, there would be no increase or decrease in net earnings from a one per cent change in the interest rates on floating rate debt as all interest has been capitalized as part of the cost of the oil sands project.

(d) Foreign Currency Risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the Corporation's operating and financial results. At December 31, 2002, the Corporation's only significant exposure to these foreign exchange risks is in connection with its United States dollar denominated debt as described in Note 6(a).

(e) Fair Values of Financial Assets and Liabilities

The fair values of financial instruments that are included in the Consolidated Balance Sheet, other than long-term borrowings, approximate their carrying amount due to the relatively short period to maturity of these instruments.

The estimated fair values of long-term borrowings have been determined based upon market prices at December 31, 2002 for other similar liabilities with similar terms and conditions, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Corporation at year-end.

	2002		2001	
	Balance Sheet Amount	Fair Value	Balance Sheet Amount	Fair Value
Floating rate debt:				
Revolving credit and term loan borrowings	$ 65,000	$ 65,000	$ 279,481	$ 279,481
Other long-term liabilities	50,859	50,859	88,825	88,825
Fixed rate debt:				
US Senior Secured Notes	710,820	700,158	–	–
Long-term borrowings	$ 826,679	$ 816,017	$ 368,306	$ 368,306

13. Commitments and Contingencies

(a) Commitments

On December 6, 1999 the Corporation executed an Authority for Expenditure ("AFE") related to the oil sands project. The original AFE obligated the Corporation to expend $709.4 million from 1999 to 2003. During the course of construction, additional costs of $377.6 million have been identified that will be required to complete the oil sands project. On the basis of this level of expenditures, the Corporation has funding arrangements that are sufficient to cover its share of commitments. The Corporation continues to pursue initiatives to optimize and refine its capital structure as it progresses through project construction to operations.

In addition, the Corporation has executed or will execute long-term third party agreements to provide for the following services and utilities; pipeline transportation of bitumen and upgraded products, electrical and thermal energy, production and supply of hydrogen and transportation of natural gas. Under the terms of these agreements, the Corporation is committed to pay for these utilities and services on a long-term basis, regardless of the extent that such services and utilities are actually used. If due to project delay, suspension, shut down or other reason, the Corporation fails to meet its commitment under these agreements, the Corporation may incur substantial costs and may, in some circumstances, be obligated to purchase the facilities constructed by the third parties for a purchase price in excess of the fair market value of the facilities.

The Corporation and the other owners of the oil sands Joint Venture have entered into long-term operating lease obligations for certain equipment related to the oil sands project in addition to the amounts committed to under the AFE. The term of the lease obligations is between three and seven years, and the agreements provide for a committed payment of 85 per cent of the original cost of the equipment to the lessor at the end of the terms. The Corporation anticipates its share of the final value of the leased equipment will total between $40 to $60 million. At December 31, 2002, the Corporation's share of committed payments amounted to $37.4 million. The estimate of lease interest obligations for the next five years, excluding any committed payments, is as follows:

2003	$ –
2004	$ 2.9 million
2005	$ 2.6 million
2006	$ 2.4 million
2007	$ 2.9 million

These long-term operating leases are held within a Special Purpose Entity ("SPE") as defined in the CICA draft guideline "Consolidation of Special Purpose Entities". The impact of consolidating the SPE at December 31, 2002 would be to increase both capital assets and long term liabilities by approximately $23.4 million.

(b) Contingencies

During the year, the Corporation has submitted claims, under its insurance policy for cost over-runs and delays in production, significantly in excess of the policy limit of $200 million. No amounts have been reflected in the consolidated financial statements in respect of this potential recovery. Management of the Corporation believes that while the policy amounts will be recovered, the timing of receipt cannot yet be ascertained.

14. Supplementary Information

(a) Net change in non-cash working capital

Source/(Use)		2002		2001
Operating Activities				
Accounts receivable	$	(4,071)	$	–
Inventory		(4,175)		–
Accounts payable and accrued liabilities		281		–
	$	(7,965)	$	–
Investing Activities				
Accounts receivable	$	4,675	$	–
Accounts payable and accrued liabilities		(10,550)		(18,231)
	$	(5,875)	$	(18,231)

(b) Cumulative Statement of Cash Flow

The following represents the Corporation's cumulative statement of cash flow from June 18, 1999 to December 31, 2002.

		Cumulative from inception
Cash provided by (used in)		
Operating		
Net loss for the period	$	(21,440)
Non-cash items		
Write-off of deferred financing costs		22,759
Future income tax recovery		(22,551)
Amortization		532
Cash from Operations		(20,700)
Increase in non-cash working capital		(7,965)
		(28,665)
Financing		
Issue of share capital		448,280
Increase in long-term debt		1,053,320
Repayment of long-term debt		(279,481)
Increase in long-term liabilities		4,250
Issue of Convertible Notes		88,000
Charge for Convertible Notes		(1,283)
Repayment of long-term liabilities		(57,032)
Debt issue and deferred charges		(50,181)
Cash Generated		1,205,873
Investing		
Capital expenditures		(1,199,996)
Restricted cash		–
Decrease in non-cash working capital		37,216
Cash Invested		(1,162,780)
Increase in cash		14,428
Cash at beginning of period		–
Cash at end of period	$	14,428

15. Subsequent Events

(a) Equity offering

On February 7, 2003, the Corporation completed a public offering for the issuance of 2,050,000 Common Shares for aggregate proceeds of $50.2 million. The offering was underwritten by a syndicate of Canadian underwriters and undertaken through the filing of a short form prospectus.

(b) Credit facility

On January 30, 2003, the Corporation increased the availability under its Revolving Facility described in Note 6(c) above by $25 million, with the addition of another Canadian chartered bank to the syndicate.

16. United States Accounting Principles and Reporting

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP) which, in most respect, conform to accounting principles generally accepted in the United States (US GAAP). Canadian GAAP differs from US GAAP in the following respects:

Reconciliation of Net Loss under Canadian GAAP to US GAAP

	Note	Year Ended December 31 2002	2001	2000
Net Loss – Canadian GAAP		$ 9,003	$ 7,015	$ 5,422
Impact of US GAAP				
Borrowing costs	v	3,295	4,410	5,369
Loss on derivative financial instruments	viii	39	–	–
Interest on Convertible notes	ix	(163)	–	–
Pre-operating costs	vi	1,374	–	–
Deferred Income Tax	iii	19,929	–	–
Net Loss – US GAAP		$ 33,477	$ 11,425	$ 10,791
Net Loss per Share				
Basic and diluted – Canadian GAAP		$ 0.21	$ 0.17	$ 0.21
Basic and diluted – US GAAP		$ 0.69	$ 0.28	$ 0.41

Consolidated Statement of Cash Flows – US GAAP

	Year Ended December 31 2002	2001	2000
Cash provided by (used in)			
Operating activities	$ (21,074)	$ (11,255)	$ (10,621)
Financing activities	512,722	404,941	185,644
Investing activities	(530,193)	(434,824)	(147,069)
(Decrease) Increase in Cash	$ (38,545)	$ (41,138)	$ 27,954

Consolidated Balance Sheet

As at December 31	Note	2002		2001	
		As reported	US GAAP	As reported	US GAAP
Assets					
Current Assets		$ 25,227	$ 25,227	$ 60,201	$ 60,201
Capital Assets	v,vi,ix	1,306,989	1,293,987	761,939	752,160
Deferred Charges		27,422	27,422	32,254	32,254
		$ 1,359,638	$ 1,346,636	$ 854,394	$ 844,615
Liabilities					
Current Liabilities	ix	$ 45,008	$ 128,953	$ 51,222	$ 54,922
Financial Liabilities	viii	–	2,600	–	–
Long-term Debt		775,820	775,820	279,481	279,481
Other Long-term Liabilities	iii	51,313	50,859	88,825	88,825
		872,141	958,232	419,528	423,228
Shareholders' Equity					
Share Capital	x	426,275	445,580	447,303	443,603
Convertible Notes	ix	83,945	–	–	–
Deficit	v,ix,x	(22,723)	(55,693)	(12,437)	(22,216)
Accumulated Other Comprehensive Income	vii	–	(1,483)	–	–
		$ 1,359,638	$ 1,346,636	$ 854,394	$ 844,615

i. Stock Based Compensation

The Corporation accounts for its stock-based compensation plans under CICA 3870, under which no compensation expense is recognized in the consolidated financial statements when stock options are granted. If compensation expense had been recorded in accordance with Statement of Financial Accounting Standard ("FAS") No. 123, the Corporation's net loss and net loss per share would approximate the following pro forma amounts:

	Year Ended December 31		
	2002	2001	2000
Compensation Expense	$ 703	$ 596	$ 552
Net Loss:			
As reported – US GAAP	33,477	11,425	10,791
Pro Forma	34,180	12,021	11,343
Net Loss per Share:			
As reported – US GAAP	0.69	0.28	0.41
Pro Forma	0.71	0.29	0.43

The fair value of each option granted is estimated on the date of grant using the Black-Scholes pricing model with weighted average assumptions for grants as follows:

	Year Ended December 31		
	2002	2001	2000
Risk free interest rate, average for year	4.55%	5.20%	5.94%
Expected life (in years)	5.00	4.00	4.00
Expected volatility	0.30	0.22	0.20
Dividend per share	–	–	–

ii. Recent Accounting Pronouncements

a) FAS 145 Accounting for Gains and Losses on Settlement of Debt
In April 2002, FAS 145 was issued rescinding the requirement to include gains and losses on the settlement of debt as extraordinary items. FAS 145 is applicable for fiscal years beginning on or after May 15, 2002. The standard has been adopted by the Corporation with no impact.

b) FAS 146 Accounting for Costs Associated with Exit or Disposal Activities
In June 2002, FAS 146 was issued. The standard requires that liabilities for exit or disposal activity costs be recognized and measured at fair value when the liability is incurred. This standard is effective for disposal activities initiated after December 31, 2002.

c) FAS 148 Accounting for Stock-based Compensation – Transition and Disclosure
In December 2002, FASB issued FAS 148 as an amendment to FAS 123 "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. FAS 148 is applicable for fiscal years beginning after December 15, 2003. The Corporation does not expect that the adoption of this pronouncement will have an impact on its financial statements.

d) FASB Interpretation 46 Consolidation of Variable Indirect Entities
In February 2003, FASB issued FASB Interpretation 46, to be effective for the first interim or annual reporting period beginning after June 14, 2003. The standard mandates that certain special-purpose entities be consolidated by their primary beneficiary. At December 31, 2002, the Corporation has an operating lease that may be consolidated under the new standard; refer to Note 13 'Commitments and Contingencies'.

e) Hedge Accounting
The CICA issued Accounting Guideline 13 "Hedging Relationships", effective for fiscal years beginning on or after July 1, 2003. The guideline establishes certain conditions for when hedge accounting may be applied, but does not specify hedge accounting methods. The Corporation does not expect that the adoption of this pronouncement will have an impact on its financial statements.

f) FAS 143 Accounting for Asset Retirement Obligations
FASB issued FAS 143, effective for fiscal years beginning after June 15, 2002. FAS 143 applies to legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, development and/or the normal operation of a long-lived asset, except for certain obligations of lessees. The effect on the Corporation's consolidated financial statements has not been determined at this time.

iii. Income Taxes

Under US GAAP, the net deferred income tax liability as at December 31, 2002 and 2001 consists of:

	Year Ended December 31	
	2002	2001
Future Income Tax assets		
Net losses carried forward	$ 19,069	$ 11,584
Share issue costs	2,096	3,191
Debt issue costs	1,386	–
Financial liabilities in excess of tax values	1,078	–
Future Income Tax liabilities		
Renunciation of deductions for flow-through shares	(23,005)	–
Tax values in excess of book capital assets	(579)	–
Debt issue costs	–	(4,132)
Less: valuation allowance	(45)	(10,643)
Net Future Income Tax Liability – US GAAP	$ –	$ –

The following table reconciles income taxes calculated at the Canadian statutory rate of 42.12% (2001 – 42.62%) with actual income taxes:

	Year Ended December 31	
	2002	2001
Loss before income taxes – Canadian GAAP	$ (28,649)	$ (5,480)
US GAAP adjustments	(4,545)	(4,410)
Loss before income taxes – US GAAP	(33,194)	(9,890)
Expected income tax	(13,981)	(4,215)
Unrecognized benefit of losses	–	4,215
Recognition of losses brought forward	(7,946)	–
Large Corporations Tax	2,905	1,535
Renunciation of deductions for flow-through shares	19,305	–
Income tax expense – US GAAP	$ 283	$ 1,535

iv. Capital Asset Impairment

Under Canadian GAAP when the net carrying value of a capital asset, less its related provision for future removal and site restoration costs and future income taxes, exceeds the estimated undiscounted future net cash flows together with its residual value, the excess is charged to earnings. Under US GAAP the Corporation would account for long-lived assets in accordance with the United States provision FAS 144 "Accounting for the Impairment of Long-Lived Assets and for the Long-Lived Asset to be Disposed of". This Statement requires that long-lived assets and certain identifiable intangibles be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets.

v. Borrowing Costs

Under Canadian GAAP, standby fees and foreign exchange gains or losses associated with borrowing facilities can be deferred as costs incurred during the pre-operating period. Under US GAAP, these costs would be expensed as incurred. The effect of this difference is to increase expenses by $3.3 million for the year ended December 31, 2002 (2001 – $4.4 million, 2000 – $5.4 million), to increase Deficit brought forward by $9.8 million (2001 – $5.4 million, 2000 – $nil) and to reduce capital assets at December 31, 2002 by $13.1 million (2001 – $9.8 million, 2002 – $5.4 million).

vi. End of Pre-operating Period

Under Canadian GAAP, the Corporation is deemed to have ended its pre-operating period upon commencement of commercial production. Until that time, training and start-up costs associated with the Project during the pre-operating period are deferred and capitalized as part of the Project. Under US GAAP, the Corporation is deemed to have ended its pre-operating period upon mechanical completion of the Project, which occurred on December 1, 2002, such that training and start-up costs are expensed thereafter. The effect of this difference is to increase expenses by $1.4 million for the year ended December 31, 2002 and to reduce capital assets at December 31, 2002 by $1.4 million.

vii. Other Comprehensive Income

Comprehensive income is measured in accordance with FAS 130 "Reporting Comprehensive Income". This Standard defines comprehensive income as all changes in equity other than those resulting from investments by owners and distributions to owners. During the year ended December 31, 2002, the Corporation had other comprehensive income arising due to unrealized losses on derivative financial instruments designated as hedge transactions. At December 31, 2002 this other comprehensive income amounted to a loss net of tax of $1.48 million.

viii. Derivative financial instruments and Hedging

Under Canadian GAAP, the derivative financial instruments qualify for hedge accounting and the payments or receipts on these contracts are recognized in earnings concurrently with the hedged transaction and changes in the fair values of the contracts are not reflected in the consolidated financial statements. US GAAP requires that all derivative financial instruments be recorded on the balance sheet as either assets or liabilities at their fair values. When specific hedging criteria is met, then changes in the derivative's fair value can be recorded in other comprehensive income and any ineffectiveness of the hedge is recorded in earnings for the period. Management has designated the derivative financial instruments as hedges and as a result, under US GAAP, the effect is to record the change in the fair value of the hedges of $2.56 million ($1.48 million net of tax) in other comprehensive income and $0.04 million in expenses. In addition, liabilities increase by $2.6 million, being the full amount of the unrealized losses.

ix. Convertible Notes

Under Canadian GAAP, amounts drawn under the Note Purchase Facility are deemed to consist of both an equity and a liability component, recognized as convertible notes. The initial carrying amount of the equity component is adjusted for accretion to bring it up to the stated principal amount of the Note Purchase Facility at maturity. This accretion is charged to the Deficit. Under US GAAP, all amounts drawn under the Note Purchase Facility are classified as a liability and any charges paid on these notes are treated as interest expense. As the Note Purchase Facility is in place to finance the oil sands project, the interest can be capitalized as part of the oil sands project costs. The effect of this difference is to reclass convertible notes of $83.9 million from shareholders' equity to current liabilities. In addition, the accretion is reversed and interest expensed under this facility can be capitalized as part of the oil sands project. The effect is to decrease expenses by $0.16 million, decrease the Deficit by $1.28 million and increase capital assets by $1.44 million.

x. Flow-through Shares

Under Canadian GAAP flow-through shares are recorded at their face value within share capital. When the expenditures are renounced and the tax deductions transferred to the shareholders, future income tax liabilities will increase and the share capital will be reduced. Under US GAAP when the shares are issued the proceeds are allocated between the offering of the shares and the sale of tax benefits. The allocation is made based on the difference between the quoted price of the existing shares and the amount the investor pays for the flow-through shares (given no other differences between the securities). A liability is recognized for this difference. The liability is reversed when tax benefits are renounced and a deferred tax liability recognized at that time. Income tax expense is the difference between the amount of the deferred tax liability and the liability recognized on issuance. At December 31, 2002, the Corporation had recognized all renouncements of the tax deductions to the investors. The effect of this difference is to increase share capital by $19.3 million (2001 – decrease of $3.7 million) and increase deferred income tax expense by $19.3 million (2001 – $nil) and no effect on current liabilities (2001 – an increase of $3.7 million).

Biographies

Directors

Glen F. Andrews
Bainbridge Island, Washington
Director since October, 1999
Retired businessman. Previously President of BHP Copper North America until June 1999. Prior thereto, Executive Vice-President and General Manager, BHP Copper of the South America and Pacific regions from 1996 to 1998 and North American region in 1998.

Tullio Cedraschi
Montreal, Quebec
Director since October, 2000
President and Chief Executive Officer of CN Investment Division, the entity responsible for investing the assets of the Canadian National Railways Pension Trust Funds.

Geoffrey A. Cumming
Auckland, New Zealand
Chairman and Director since October, 1999
Vice-Chairman of Gardiner Group Capital Limited, Toronto, a private Canadian investment corporation, and Deputy Chairman of Emerald Capital Limited, a private New Zealand investment corporation.

Walter W. Grist
New York, New York
Director since December, 1999
Managing Director, Brown Brothers Harriman & Co., a private investment management and banking partnership which is general partner of The 1818 Fund III, L.P.

Brian F. MacNeill
Calgary, Alberta
Director since October, 1999
Chairman of Petro-Canada since 2000. President and Chief Executive Officer of Enbridge Inc., an energy transportation, distribution and services corporation, from 1991 to September 1, 2000.

Robert G. Puchniak
Winnipeg, Manitoba
Director since October, 1999
Executive Vice President and Chief Financial Officer of James Richardson & Sons, Limited ("James Richardson"), an investment and holding corporation, since March 2001. Prior thereto, Vice-President, Finance and Investment, James Richardson since 1996.

Guy J. Turcotte

Calgary, Alberta

President, Chief Executive Officer and Director since July, 1999

President of Western since January 2002 and Chief Executive Officer of Western since July 1999; Chairman of Fort Chicago Energy Partners, L.P. since September 1997 and Chief Executive Officer until December 2002; Chief Executive Officer of Stone Creek Properties since March 1998; prior thereto, founder, Chairman and/or President and Chief Executive Officer of Chauvco Resources Ltd. from January 1981 to December 1997.

Mac H. Van Wielingen

Calgary, Alberta

Director since December, 1999

Chairman of ARC Financial Group Ltd. ("ARC"), a private investment management and merchant banking company, and previously, President of ARC since 1989.

Officers

Charles W. Berard

Calgary, Alberta

Corporate Secretary

Partner with Macleod Dixon LLP, Barristers & Solicitors.

David A. Dyck

Calgary, Alberta

Vice President, Finance and Chief Financial Officer

Vice President, Finance and Chief Financial Officer of Western since April 2000; prior thereto, Senior Vice President Finance & Administration and Chief Financial Officer of Summit Resources Limited ("Summit") since September 1998; Vice President Finance and Chief Financial Officer of Summit from October 1996 to September 1998.

John Frangos

Calgary, Alberta

Executive Vice President and Chief Operating Officer

Executive Vice President and Chief Operating Officer of Western since January 2002; prior thereto Corporate Development, Western since May 1999; previously Vice President International Business Development of BHP Minerals from 1997 to May 1999.

Gerry Luft

Calgary, Alberta

Vice President Marketing

Vice President Marketing of Western since January 2002; prior thereto President of ProServ Energy Inc.

Corporate Governance

Composition of the Board

The Board currently consists of nine directors who provide a wide diversity of business experience. Eight of the board members are independent of management and are unrelated directors. Each of the unrelated directors is free from any business or other relationship which could reasonably be perceived to materially interfere with the director's ability to act with a view to the best interest of the Corporation, other than interests and relationships which arise solely as a result of shareholding.

Board Committees and their Mandates

The Board has four committees. Each committee has three members who are unrelated directors. The committees are: Audit Committee, Compensation Committee, Corporate Governance Committee and the Health Safety and *Environment Committee*.

Audit Committee

Chair: Robert G. Puchniak

Members: Brian F. MacNeill, Mac H. Van Wielingen

The Audit Committee reviews Western's interim unaudited consolidated financial statements and annual audited consolidated financial statements and certain corporate disclosure documents including the annual information form, management's discussion and analysis, offering documents including all prospectuses and other offering memoranda before they are approved by the Board. The Committee reviews and makes a recommendation to the Board in respect of the appointment of the external auditor and it monitors accounting, financial reporting, control and audit functions. The Audit Committee meets to discuss and review the audit plans of external auditors. The committee questions the external auditor independently of management and reviews a written statement of its independence based on the criteria found in the recommendations of the Canadian Institute of Chartered Accountants. In addition, it reviews and reports to the Board on Western's risk management policies and procedures and reviews the internal control procedures to determine their effectiveness and to ensure compliance with Western's policies and avoidance of conflicts of interest.

The Audit Committee is also charged with reviewing the report of the independent engineers relating to the Corporation's reserves. The committee will meet independently of management with the independent engineers to review the evaluation report, the corporate summary of the reserves and future cash flows of the oil sands properties and other related matters. In addition, it will review the Corporation's relationship with the independent consulting firm.

Compensation Committee

Chair: Geoffrey A. Cumming

Members: Robert G. Puchniak, Glen F. Andrews

The Committee reviews successions plans for key management positions within the Corporation, human resource policies and plans, the performance and development of the CEO and other senior officers of the Corporation. The Committee makes recommendations to the Board with respect to the salary and other remuneration to be awarded to senior executive officers of Western. It also makes recommendations to the Board in respect of all other compensation matters including long- and short-term incentives such as bonus, stock option plans and other benefits and is responsible for developing these programs.

Corporate Governance Committee

Chair: Mac H. Van Wielingen

Members: Geoffrey A. Cumming, Brian F. MacNeill

The Governance Committee's mandate is to assess the effectiveness of the Board as a whole, the various other committees as well as individual directors. It also assesses the Corporation's approach to corporate governance and monitors the relationship between management and the Board. This Committee is responsible for recommending candidates to the Board for nomination as directors and for the composition of various Board committees and for recommendations regarding Chairmanship of the Board. The committee, together with the Compensation Committee, also reviews and recommends compensation for Board and committee service. The Governance Committee is also mandated to undertake those initiatives as are necessary to maintain a high standard of corporate governance practices and in this respect is reviewing and implementing, as appropriate, certain recommendations set out in the Final Report of the Joint Committee on Corporate Governance, dated November, 2001.

Health, Safety and Environment Committee

Chair: Glen F. Andrews

Members: Tullio Cedraschi, Walter W. Grist

The Health, Safety and Environment Committee's mandate is to monitor the health, safety and environmental practices and procedures of Western and its subsidiaries for compliance with applicable legislation, conformity with industry standards and prevention or mitigation of losses. It reviews, reports and, when appropriate, makes recommendations to the Board on the Corporation's policies and procedures related to health, safety and the environment.

Corporate Information

Officers

Geoffrey A. Cumming
Chairman of the Board

Guy J. Turcotte
President and Chief Executive Officer

John Frangos
Executive Vice President and Chief Operating Officer

David A. Dyck
Vice President, Finance and Chief Financial Officer

Gerry Luft
Vice President, Marketing

Charles W. Berard
Corporate Secretary

Directors

Geoffrey A. Cumming
Chairman of the Board, Western Oil Sands Inc.
Vice Chairman,
Gardiner Group Capital Limited, Toronto
Deputy Chairman, Emerald Capital Limited
Auckland, New Zealand

Glen F. Andrews
Retired, formerly President,
BHP Copper North America
Bainbridge Island, Washington

Tullio Cedraschi
President & Chief Executive Officer,
CN Investment Division
Montreal, Quebec

Walter W. Grist
Managing Director,
Brown Brothers Harriman & Co.
New York, New York

Brian F. MacNeill
Chairman, Petro-Canada
Calgary, Alberta

Robert G. Puchniak
Executive Vice President, Chief Financial Officer,
James Richardson & Sons Limited
Winnipeg, Manitoba

Guy J. Turcotte
President and Chief Executive Officer,
Western Oil Sands Inc.
Calgary, Alberta

Mac H. Van Wielingen
Chairman, ARC Financial Group Ltd.
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Auditors

PricewaterhouseCoopers LLP
Calgary, Alberta

Legal Counsel

Macleod Dixon LLP
Calgary, Alberta

Paul, Weiss, Rifkind, Wharton & Garrison
Washington, D.C., USA

Evaluation Engineers

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

Registrar and Transfer Agent

Valiant Corporate Trust
Calgary, Alberta

Stock Exchange Listing

The Toronto Stock Exchange
Trading Symbol: WTO

Annual Meeting

The Annual General Meeting of the Shareholders of Western Oil Sands will be held on May 7, 2003 at 3:30 pm at the Metropolitan Centre, Calgary, Alberta.