A history of the oil sands

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Canada's oil sands:

a history of the world's largest petroleum storehouse

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CHAPTER 16:

People struggled vainly for 84 years to unlock the energy resources trapped in the world's largest petroleum deposits. Scientists, entrepreneurs, engineers invested hope, money, and often incredible toil in trial after trial, effort after effort, project after project, that resulted in heartbreaking failure after failure. But they were not failures so much as stepping stones in the progress that led to the world's first large-scale commercial oil sands production. Now, 121 years and billions of dollars after the first attempt using water to wash bitumen from sand, Alberta's oil sands provide half the oil produced in Canada, and 10 percent of North America's oil supplies. Some predict that the oil sands will provide as much as 90 percent of Canada's oil production early in the 21st century. But the struggle continues, because all the efforts have so far found out how to unlock only a fraction of the energy resource stored in Alberta's storied Athabasca and other, smaller oil sands deposits, and there are technological, resource, environmental, and economic challenges still to be met.

For more than half a century, the people of Fort McMurray had watched the oil men come and go.

The oil men had come to dig from the banks of the Athabasca and Clearwater Rivers a plastic mixture of sand and bitumen they called the Athabasca tar sands, now known as the Alberta oil sands. They dug holes, drilled wells, experimented with underground fires, studied plans for an underground nuclear explosion, and built plants to mine and process the tar sands. They came with visions of developing the world's largest oil deposit, and they left, despairing, defeated, and frustrated.

Fort McMurray has seen a lot of history since that day in 1788 when fur trader Peter Pond arrived to establish his "Fort of the Forks" near the junction of the Athabasca and Clearwater Rivers. This was the heart of the storied Athabasca country, hub of a fur-trading empire that stretched from the Great Lakes to the Pacific Ocean, from Alaska to California. From Montreal and Hudson Bay, the fur traders paddled their canoes to — men such as Peter Pond, David Thompson, Alexander Mackenzie, George Simpson and Simon Fraser — men who first explored, mapped and tamed the northern half of the North American continent. More than a century and a half later, half the population of Fort McMurray was Metis and names such as Mackenzie, Fraser and MacDonald were common in the area.

Fort McMurray became the staging area for transportation into the Arctic northwest, the start of a 1,700-mile transportation system down the Athabasca and Mackenzie Rivers as far as the Arctic coast. First canoes, then the steam-powered, wood-burning tugs of the Hudson's Bay Company plied the broad, placid waterways downstream from Fort McMurray. In 1916 it became the terminus of the 250-mile Northern Alberta Railway from Edmonton, and heavy freight and supplies were loaded here on the barges towed by the throbbing diesel tugs of the federal government's Northern Transportation Company.

During the Second World War, some 2,500 members of the U.S. Army and 50,000 tons of equipment were transferred from rail to barge at Fort McMurray for shipment 1,100 miles downstream for the Canol project. Later, Fort McMurray handled the freight moving in and out of Uranium City on Lake Athabasca where the government's Eldorado Mining and Refining was developing production from what was then the world's richest known uranium ore body. These were hectic, exciting years for Fort McMurray.

Then came the slump. A new highway and then a railway to Hay River on Great Slave Lake bypassed the transportation route to the far North through Fort McMurray. With a world glut of uranium, activity at Uranium City ground to a halt. Tugs of the Northern Transportation Company were beached. Athabasca's historic fur trade industry shrank to a shadow.

"This seemed like God's forgotten country," Clair Peden, road construction contractor and former mayor of Fort McMurray recalled in the late 1960s.[1] It looked like it, too. In 1960, it was a one-street town (a street of either mud, dust, or snow, depending on the season) with a single clapboard hotel, a lonely service station, a few frontier stores, and a collection of mostly unpainted shacks and log cabins, housing a population of 1,100. And still the oil men kept coming and going to drill their wells, study the oil sands, conduct their experiments, and operate their pilot plants. The people of Fort McMurray no longer cared. They had long since lost all faith and hope in the plans of the oil men. They knew that literally beneath their feet lay the largest known deposit of oil in the world, and for all that they could tell, it would be there forever.

"When the real thing finally came, hardly anyone would believe it," Clair Peden recalled.

The real thing finally came in 1964 when first hundreds, and then finally as many as 2,000 men, together with hundreds of thousands of tons of equipment, supplies and material moved through McMurray to the site of a vast construction project 20 miles northwest of the town. Slowly it dawned on the people of Fort McMurray that this time it was for real. By the time the $280-million complex of Great Canadian Oil Sands Limited was completed in 1967, McMurray was a far different town. No longer a poverty-ridden backwater, it was a thriving town of 5,000 people, as modern as tomorrow, "the oil capital of the world," as it billed itself. And the town's growth had just started.

More than three-quarters of the Athabasca oil sands consist of a beautiful white sand, with the rest consisting mostly of bitumen plus a little clay, silt and minerals. They embrace an area of 30,000 square miles, an area twice as large as Lake Ontario. The sands range in thickness from a few feet to 300 feet and are covered with overburden measured in inches to 2,000 feet. All this is set in a gently rolling land covered by scrub trees, cut by deep-banked rivers, pockmarked by a myriad of lakes and embracing endless miles of muskeg. Together with smaller deposits to the south at Cold Lake and to the west in the Peace River country, there are 1.6 trillion barrels of bitumen buried in Alberta's oil sands. Some 178 billion barrels of this are estimated to be recoverable under economic and operating conditions prevailing in 2003, according to Alberta's Energy and Utilities Board.[2] To put that in perspective: Alberta's economically recoverable bitumen reserves were more than three times the remaining discovered conventional oil supplies of North America, and 18 percent of the world's. Only Saudi Arabia had greater oil reserves.[3] Billions of dollars are meanwhile being spent in efforts to ultimately bring to market much of the as yet economically unrecoverable 90 percent of Alberta's oil sands energy.

Looking for the motherlode

First recorded mention of the Athabasca oil sands was by Peter Pond who, in 1788, noted the black gunk oozing from the banks of the Athabasca River and reported that the Indians used it to caulk their canoes. "Some bituminous fountains in which a pole 20 feet long may be inserted without the least resistance," were noted the following year by Alexander Mackenzie during his historic voyage to the Arctic coast.

GSC geologist Robert Bell examined the oil sands in 1881 and 1884 and was the first to suggest that there might be great commercial value here, with a pipeline to Hudson Bay and shipments to world markets. Bell wrote:

Independent of railway construction, an outlet for the oil to foreign markets might be found by conveying it by steamers, for which there is uninterrupted navigation, from the Athabasca River to the eastern extremity of the lake of the same name, and thence, by a pipe to Churchill Harbour on Hudson Bay.[4]

When the early geologists and oil explorers first looked at the Athabasca oil sands there were two visions of great oil wealth. The most obvious lay in the bitumen that is near the surface. Another concept held that the oil sands are merely somewhat baked and dried-out crude oil that had seeped to the surface from deeper Devonian rocks, and that even vaster and far more profitable quantities of liquid crude oil awaited only the drill bit in these deeper formations.

In his reports on the Athabasca tar sands, Bell wrote:

The enormous quantity of asphalt, or thickened petroleum, in such a depth and extent of sand indicates an abundant origin. It is hardly likely that the source from whence it came is exhausted. The whole of the liquid petroleum may have escaped in some parts of the area below the sandstone, while *in others it is probably still imprisoned in great quantities and may be found by boring.*[5]

George Dawson, later director of the GSC, told a Senate committee in 1888 that there was "reason to believe that extensive deposits" of crude oil existed at Athabasca and that "the quantity appeared to be practically inexhaustible."[6]

With this type of promise in mind, it was inevitable that wildcatters would start punching holes through the oil sands looking for the liquid motherlode that the best geological brains believed lurked there. First in the field was the Geological Survey itself, which drilled at the town of Athabasca in 1893 and 1894 to a depth of 1,770 feet without reaching even the oil sands, let alone a deeper oil pool. Three years later, the GSC drilled its famous Pelican wild gas well, which burned out of control for 21 years. George Dawson is reported to have "expressed concern and disappointment at finding maltha or tarry oil instead of liquid oil at Pelican Portage."[7]

Thirty-six wells were drilled in the Athabasca region from 1893 to 1924[8] in search of the elusive basement oil. Most were drilled by small wildcatters and stock promoters but two of them, drilled in 1917 to 1919, were the first wells drilled in Western Canada by Imperial Oil. Some of the promoters reportedly salted their wells by dumping volumes of crude oil downhole to be pumped up later for the edification of credulous investors.

There was a period of feverish speculation and a short-lived boom in Fort McMurray that sent land prices from a few dollars to as much as $200 per lot in 1912. The most active of the early Athabasca drillers was a German immigrant, Count von Hammerstein. He is seen in a photo on horseback looking every inch the German aristocrat, garbed with polished knee-length boots, a military tunic, cape, and plumed hat. He appears to have arrived at Fort McMurray from Winnipeg where he and two associates in early 1906 incorporated the Bonnet Falls Power Company to build a suburban electric railway that came to exist only on paper. Later that year he drilled the first of nine wells at Athabasca, finding a small amount of heavy oil which some reports suggest were salted, but which nevertheless fuelled the mini-speculative boom. Von Hammerstein died impoverished, but obsessed with the hoped-for value of his tar sands properties.

Some of the early Athabasca wells found significant amounts of natural gas. A well drilled a short distance south of Fort McMurray by Northern Alberta Exploration Company found a thick section of salt, which led to the formation of the Alberta Salt Company and a business pumping brine and making salt. None of the Athabasca wildcat tests ever found the basement oil, of course, but they were not entirely failures. They found gas and salt and they contributed to the growing knowledge about Alberta's oil sands.

Washing out the sand

While searching for the non-existent basement oil was underway, other efforts were focused on mining Athabasca's oil sands and seeking a way to extract the bitumen, most commonly with the use of hot water. Eighty-seven years of testing and experiments preceded Great Canadian Oil Sands' use of hot water to wash away the sand from the bitumen. When Geological Survey of Canada geologist Robert Bell looked at the bitumen oozing from the banks of the Athabasca River, he shipped samples of the sands to Ottawa where G. Christian Hoffmann, the GSC's chemist and metallurgist, conducted experiments to examine the possibilities. Hoffmann thought the sands were "admirably adapted . . . for asphalting purposes" with "very slight treatment" and without the need to separate the sand and bitumen. They were, he wrote, suitable for "construction of roads, footpaths, courtyards, and for asphalting the floors of granaries, basements of warehouses . . . and as a roofing material."[9]

Should anyone want to bother separating the bitumen, however, Hoffmann concluded that this would be a simple matter. It could, he wrote, "be effected by simply boiling or macerating the material with hot water, when the bituminous matter entering into fusion will rise as scum to the surface and may be removed by skimmers, whilst the sand falls to the bottom of the vessel." That's not far off from the basic approach used in today's multi-billion dollar oil sands plants, albeit with enormous refinements to the process.

Unfortunately, Hoffmann's macerating didn't remove quite all of the most minute particles of sand. The bitumen he extracted by this method still contained 50.1 percent very fine sand. It would take a little more than "simply boiling" to completely remove it.

Hoffmann added that, given greater quantities than his few samples, the bitumen might be distilled and "advantageously employed as a crude material for the manufacture of illuminating and lubricating oils and paraffin." This was still the age of coal oil lamps.

Other government-funded researchers seeking ways to extract the bitumen would follow in Hoffmann's footsteps, while there were more than 30 private sector attempts, using hot water, steam, fire, solvents, and even microbes, that were supposed to separate the bitumen by eating it.

Sidney Clarke Ells, an engineer with the federal Department of Mines, in 1913 set out for Athabasca to survey the prospects of commercial production, a task to which he devoted the next 32 years. It was pioneering under conditions as difficult as any fur trader ever faced — travelling by foot with a 70-pound backpack the 250 miles over trackless muskeg and forest between Edmonton and Fort McMurray; camping out under northern stars at temperatures as low as -40∞C; hauling on a tracking line 20 hours a day to help pull barges up the Athabasca River.

Ells set out from Athabasca Landing (north of Edmonton) with a 30-foot scow, a 22-foot freight canoe and a "crew of three white men and an alleged native pilot." Floating downstream it took the party only nine days to cover the 240 miles to Fort McMurray. In the following three months Ells' party located 247 tar sands outcrops extending over a distance of 185 miles along the banks of the Athabasca and tributary rivers, and collected more than 200 samples from

Glenbow Archives NA 71-187

Track teams in 1914 pull scow load oil oil sands from Fort McMurray, 240 miles up the Athabasca River. A large volume was moved in winter by horse teams to Edmonton, where it was used for road paving.

hand-augured holes to depths of five to 17 feet. It took 23 days, with Ells and a 12-man crew of natives pulling 20 hours a day on a track line, on the return trip which brought out the first meaningful tar sand samples.

Ells' report of his field work in 1913 concluded that "certain areas should lend themselves to large scale commercial development," with the most promising use as a paving material. He also reported that "discovery of petroleum fields in Western Canada will have a direct bearing on the development of Alberta bituminous sands."[10]

The oil sands samples that Ells had shipped out in 1913 were used in Ottawa and in Pittsburgh to test methods of extracting the bitumen by means that would be further tested by others over the next half century. Ells and his associates tried centrifuges, solvents, distillation, and hot water. The most encouraging results were obtained at the Mellon Institute of Industrial Research in Pittsburgh where hot water and varying amounts of acidic and alkaline reagents were used in three types of flotation cells.

In the early winter months of 1915, Ells shipped out 60 tons of tar sands from McMurray to Edmonton by horse team "in temperatures ranging from 20 to 50 below zero and without tents for men or horses."[11] The following year the Northern Alberta Railway was completed to within 17 miles of Fort McMurray (it was another 10 years before the final stretch was built). That summer Ells used the tar sands for experimental paving of Edmonton streets, pavement that was still in use half a century later. The tar sands material was also subsequently used for paving in the Jasper National Park. In 1930 Ells built a large mixing plant, housed on a railway flat-car, for preparing paving material at a rate of 700 tons per day. The plant was used for a period of two months, but with Alberta gripped by the Depression, there was very little road construction, and the plant was eventually sold for scrap. In the end, the cost of transporting raw tar sands from Athabasca made its use economically unfeasible.

Oil sands now are moved in giant trucks from mine site to nearby processing facilities where oil and sand is removed, the bitument upgranded, and shipped by pipeline across North America.

Another bitumen paver was Thomas Draper, an oil equipment manufacturer from Petrolia, Ontario. In 1920 Draper experimented with heat to distill the bitumen from the sand, then spent 16 years mining oil sands, separating sand and bitumen by hot water flotation, and paving roads and streets. From 1922 to 1926, Draper mined more than 1,500 tons of oil sands for use in tests and experiments by the Alberta Research Council.[12] Draper's McMurray Asphaltum and Oil Company spent $35,000 to build a water flotation separation plant near Fort McMurray, but in 1924 it was the first of three pioneer oil sands plants to be destroyed by fire. During the next dozen years, Draper won contracts to successfully pave a portion of Parliament Hill and a short stretch of Wellington Street in Ottawa, and other roads and streets in Alberta towns, including Medicine Hat, Vegreville, and Camrose.

But it was clearly Ells who was first in the field aggressively pursing opportunities for commercial development of the oil sands. Max Ball, possibly the most widely known petroleum authority in mid-20th century and a major figure in development of the oil sands, in 1950 described Ells as "the father of the Alberta bituminous sands research and development." Ball credited Ells with having made the first "systematic study of the deposits," the first "comprehensive maps of the area in which they lie," the "first systematic study of methods for separating the bitumen from the sands," and the first to have "developed and demonstrated the principle of hot water separation."[13]

That description of Ells could not have sat well with Dr. Karl Adolf Clark, who has also been called the father of oil sands development, having spent nearly 40 years improving hot water flotation technology. Clark began his studies in 1920, seven years after Ells had first entered the field, working for the newly formed Alberta Research Council. At first, "in the spring of 1917, Ells had happily shared information about the oil sands with the University of Alberta," oil sands historian Barry Glen Ferguson claims.[14] But three years later, "Ells was co-operative neither with the University nor with its offshoot, the Research Council of Alberta." As for the Alberta scientists, as well as other business and government officials, they thought "Ells was a man to be avoided," and they did not want to work with him. Perhaps there was an element of professional rivalry. Perhaps it was personality conflicts. There might have been an element of federal-provincial tension: Ells represented the federal government working on Alberta's resources; it would hardly seem surprising if Alberta placed greater emphasis on the efforts of its own scientists. Whatever the cause, it did not help that in his first report, a year after he started his studies, Clark claimed that he had found a "new method" — hot water flotation — to extract the bitumen, without any reference to the work of Hoffmann, Ells or others. Ferguson archly suggests that Clark did not want to share any credit, that he "was ignoring the cumulative nature of his technique for reasons that seem unlikely to yield documented explanation."[15] Ells, too, was probably guilty of the same thing.

Regardless of these relations, no one spent more time nor greater effort in developing the hot water flotation process than Clark. Working with $300 worth of test equipment, Clark seemed confident that he had solved the problems almost immediately. Barely a year after his appointment, Clark confided to the university's president, Henry Marshall Tory, that "something definite has been accomplished and a very considerable glimmer of daylight let through the problem."[16] Later the same year, he announced that, "Most of the purely inventive work has now been done. There remains to be accomplished the practical application of the new methods to the production of bitumen from the tar sands. This means . . . commercial production."[17]

But it wasn't quite that easy nor quick. None of Clark's projects nor others he was associated with resulted in sustained commercial oil sands production until the GCOS plant began producing 46 years later.

Clark and his assistant S.M. Blair built their first hot water separation plant in the basement of the university's powerhouse and the following year built a larger plant at Edmonton's Dunvegan railway yards. This plant was moved to a site on the Clearwater River south of Fort McMurray in 1929 where it operated well enough to produce some bitumen used to pave Edmonton roads. Clark and the rest of the Research Council transferred to teaching duties at the university during the Great Depression, where Clark remained until his retirement in 1954 as head of the Department of Mining and Metallurgy. After retiring from the university, Clark continued his oil sands efforts, working from an office and laboratory space at the Research Council. In the 1960s, Clark was retained by Great Canadian Oil Sands as a special consultant to help in yet one more effort to apply his process in a commercial application. But he never did see it brought to fruition. He died in December 1966, just seven months before the GCOS plant began production.

About the time that Clark started his research work, a group of New York City policemen acquired leases in the Athabasca oil sands and formed Alcan Oil Company, selling out in 1923 to R.C. Fitzsimmons, who re-organized it as the International Bitumen Company.

Fitzsimmons developed his own hot water flotation process — in principle similar to Clark's but different substantially in application — and, using less than $50 worth of materials, managed to construct a make-shift unit. Fitzsimmons' operation was enlarged several times (by 1941 the firm had invested more than $300,000) and, in a limited sense, was really the first successful commercial oil sands operation. The bitumen that Fitzsimmons produced was not completely free of sand or clay particles and certainly was not suitable for refinery feedstock. But it was a fine product for waterproofing roofs and was sold for this purpose through a Western Canadian chain of hardware stores. Following a series of changes in name and ownership, Fitzsimmons' company eventually became Great Canadian Oil Sands, and finally, Suncor Energy.

Another attempt at oil sands production resulted from a visit to Denver in 1929 when Ells outlined the possibilities of the oil sands deposit to U.S. oil man Max W. Ball and his associates. The following year Ball formed Canadian Northern Oil Sands Products Limited, which later became Abasand

Suncor Energy photo

Most Athabasca area oil sands are now recovered by strip mining, but 80 percent of the oil sands and must be produced *in situ.*

Oils Limited, and during the next 15 years funnelled more than $2 million into oil sands development, some of it financed by the federal government during the Second World War in an effort to secure more oil supplies.

After conducting laboratory research and pilot plant work, Ball had a plant in operation in 1940, capable of processing 400 tons per day of oil sands. By September the following year the plant had produced 17,000 barrels of bitumen which was refined into gasoline, diesel oil, fuel oil, and coke. Then fire destroyed the plant.

The Abasand plant was rebuilt and one of those involved in this wartime effort was Harold Rea, GCOS's first chairman. Rea had been manager of sales with Canadian Oil Companies, Limited — best known for its White Rose gasoline — when he was loaned to the federal government's Wartime Oil Administration. "During the dark days of World War Two, Canada was hard-pressed to meet even essential petroleum needs," Rea later recalled. "Submarine warfare had already closed down a large East Coast refinery. The Canadian Wartime Oil Administration was forced to initiate development of every known Canadian source of petroleum, including the Athabasca tar sands." After the war, Rea returned to Canadian Oil Companies where he became president until 1963 when the company was acquired by Shell.

The government took over the Abasand property on a temporary basis, redesigned the facilities to incorporate some improved separation methods, and by 1944 once more had the plant in operation. But in the following year, the ill-fated Abasand plant was for a second time destroyed by fire. Abasand, however, managed to retain a 25-percent interest in certain Athabasca leases, including the 4,000-acre lease from which GCOS developed its first oil sands production.

Despite initial success in selling bitumen as a waterproofing compound, Fitzsimmons' International Bitumen Company also had its share of troubles. In 1942 Fitzsimmons sold out to a group of Canadian and British investors headed by Montreal financier Lloyd R. Champion and the firm's name was again changed, to Oil Sands Limited. In 1944, Oil Sands and the Alberta government started work on a $500,000 pilot plant to further test the hot water separation methods developed by Clark and the Research Council. The plant was completed in 1949 and based on the results an economic study sponsored by the Alberta government in 1950 concluded that commercial production of the Athabasca tar sands was economically feasible. But there was no great rush by oil companies to exploit the oil sands on the basis of the findings of a government study. The large fields of conventional oil then being discovered in Alberta offered far more profitable sources of petroleum than those star-crossed oil sands.

Pew's big gamble

With a string of such profitable oil discoveries as Leduc, Redwater, Bonnie Glen, and Wizard Lake, who needed the tar sands?

John Howard Pew, that's who. Pew was chairman of Sun Oil Company and a son of the company's founder. Controlled since its inception by the Pew family, Sun Oil in 1967 ranked as the 12th largest U.S. oil company. Its operations embraced shipbuilding, oil production in the United States, Canada, and Venezuela, petroleum marketing in the Eastern United States, Quebec, and Ontario, and refineries in Pennsylvania, Ohio, Texas, and Ontario. But Sun had historically been a crude-deficit company, its refineries using more oil than its oil wells could produce. It was one of the first American oil firms to join the Alberta oil search in the post-war period, three years before the Leduc discovery, but its success had been modest.

From Sun Oil's headquarters in Philadelphia, the Pew family had maintained a keen interest in the Athabasca oil sands since 1944 when John Edgar Pew — Jack Pew, to his associates — Sun's exploration and production vice-president, held discussions with Champion, whose Oil Sands Limited was searching for money for another tar sands mine and plant. Sun decided that the time for oil sands was not quite ripe, but in 1954 acquired a 75-percent interest from Abasand Oils in 4,000-acre lease number 86 at Athabasca. Oil Sands Limited, meanwhile, had again changed its corporate coat and in 1953 emerged as Great Canadian Oil Sands. In 1958, GCOS contracted with Sun Oil for the rights to mine and process the sands from lease number 86 (subject to royalty payments to Sun and Abasand) while Sun also contracted to purchase 75 percent of production from a plant proposed by GCOS which would produce 31,500 barrels per day of synthetic crude.

GCOS formally applied in 1960 for Alberta government authorization for its complex. It finally won approval in October 1962, and the permit stipulated that construction was to start by 1964 with completion by September 30, 1966. But this was far from the end of troubles for GCOS.

During hearings before the Alberta Oil and Gas Conservation Board, competing applications for oil sands projects were made by Imperial Oil and three affiliated oil companies — Cities Service, Richfield Oil Corporation, and Royalite — and by Shell Canada. Both the Imperial group and Shell sought authorization for projects that would each produce 100,000 barrels per day of synthetic oil, maintaining that this was the minimum economic production and implying that the GCOS project was too small to be economically viable.

The government was anxious to see some commercial production from the oil sands, for this would ensure continued production when Alberta's conventional oil wells began their inevitable slow decline. In its request for a permit, GCOS pointed to evidence "that additional sources of Canadian oil must be brought into production if Canada is to supply its domestic and U.S. export needs and still keep a prudent life of reserves," especially in the face of dwindling supply and increasing demand in the United States.

The government appeared to agree, yet it was also concerned about the preferential treatment that oil sands production required and the possible effects on the conventional oil producing industry. To be economical, an oil sands plant would have to operate at essentially 100 percent of design capacity, at a time when about half the production capacity of the province's oil wells was shut in for lack of market demand. Moreover, since this would be marginal-cost production, it did not look as though oil from the oil sands could enrich the provincial coffers to the same extent as conventional oil. The government did not want any impairment of an oil producing industry from which it reaped a quarter of a billion dollars a year. The result was that the government authorized the small GCOS plant, and deferred until 1969 decisions on the Imperial Oil group and Shell applications.

Now GCOS had its permit, and all it needed was the money to build the plant, an amount estimated at $110 million in 1960 but revised to $122 million by 1962. Up to this point, financing for GCOS had come primarily from Canadian and English investors, and Champion, who had bought out International Bitumen in 1942, was still a major shareholder. To help raise the money it needed, GCOS granted an option to Canadian Pacific Railway to purchase a 51-percent interest in the company; the CPR in turn had assigned one-third of this option to Sun Oil and one-third to Canadian Oil Companies, which by that time, however, had been acquired by Shell Canada.

Before putting up the money, the CPR and Shell took another hard look at the project and dropped their options, which left Sun holding the ball. Sun wasn't certain that it wanted it either — certainly not at a production rate of 31,500 barrels a day.

The decision that faced Sun's directors at a board meeting in Philadelphia in 1963 was whether or not to put up $67.5 million to acquire 87 percent interest in Great Canadian Oil Sands (later increased to 96 percent) and assist in borrowing the remaining money for an expanded development now estimated to cost $190 million. The contemplated investment was conditional on Alberta's approval to increase planned production capacity from 31,500 to 45,000 barrels per day of synthetic crude oil.

The directors were well briefed on the pros and cons and alternative opportunities to increase oil production, particularly in Venezuela. Investing in GCOS would mean committing a substantial portion of the company's financial resources to a venture where operating costs and results were unproved, where the technology was mostly untried, where the profit would depend on everything working out as calculated and within budget. It was a big gamble — larger, perhaps, than the company realized, because by the time the operation achieved design capacity, the cost was not $190 million but $280 million.

An oil sands plant, however, held the promise of a number of advantages. To meet its product sales, Sun in 1963 was a net buyer of some 75,000 barrels a day of crude oil and refined products, the amount that exceeded the production from its oil wells. GCOS would help bring production closer into balance with product sales. Sun refineries would be assured of a continuing oil supply at a constant price, regardless of future supply-demand trends or government restriction on foreign oil imports (Canadian crude was exempt from then existing U.S. oil import controls). With conventional U.S. crude supplies declining, development of a synthetic crude oil industry, based on Alberta oil sands, oil shales, or coal, might well be the answer in meeting future U.S. petroleum needs.

The first firm to establish such production would have a big competitive edge, and might thereby reap benefits eventually, even if initial rewards were slim. Integrated oil companies with production in balance or in excess of the needs of their own refineries could hardly afford to cut back their conventional oil production to accommodate more expensive synthetic crude at their refineries. Thus if the GCOS plant did turn out to be the precursor of a large synthetic industry, Sun's crude deficit position could really turn out to be an advantage after all.

As Sun's directors debated risk and reward, the most eager advocate for going ahead in Athabasca was the company chairman, 81-year-old J. Howard Pew. When Sun assigned George Dunlap to Calgary to head its Alberta operations in 1949, he was called into Pew's office. From a file cabinet, the patriarch picked out a thick file marked "Athabasca Tar Sands" and reviewed its maps, reports and memos with the head of the company's new Canadian division. "I believe the Athabasca tar sands will, some day, be of great significance to the needs for petroleum in North America," Pew is reported to have said. "I want you to be sure that Sun Oil always has a significant position in the Athabasca tar sands area."[18]

Now it was time to do it or drop it. As the directors debated, Pew reputedly warned them: "I have been closely following progress at the Athabasca tar sands for 20 years. If Sun does not go ahead with this project, I will." Sun did.

The Alberta government approved the revised plans of Great Canadian Oil Sands in April 1964. One of the conditions of the approval was that the plant was to be in production by September 30, 1967.

On September 25, 1967, some 500 government, industry and press representatives from throughout North America flew to Fort McMurray to attend the dedication of the complex, which was already producing synthetic crude. Within a few weeks the product would be starting its pipeline journey of nearly 3,000 miles to refineries in Ontario and Ohio. The dedication ceremonies were held in the "bubble," a huge fabric structure supported by compressed air and formerly used to cover winter construction at the plant site. The sound of heavy equipment and the shrill siren blast from the excavating machines reverberated throughout the bubble, signifying here was a project so urgent that production couldn't be stopped even momentarily for the official dedication.

Suncor Energy

A section of a reclaimed Suncor oil sands mining site.

There was a long head-table of company officials and visiting dignitaries and an endless procession of speakers. Sidney Ells was there, a living witness to the 54 years of hopes and frustrations that had passed since that day he had first arrived at Athabasca by river scow to assess possibilities of developing the tar sands.

At the head table, an old man sat silent, impassive, through the lengthy speeches, huddled deeply into a blue overcoat with the collar turned up at the back, and with rimless spectacles riding down an ample nose. When everyone had their say, the old man got up to speak, and it was evident that John Howard Pew, approaching 90, was still the undisputed captain of Sun Oil.

"No nation can long be secure in this atomic age unless it be amply supplied with petroleum," Pew said. "It is the considered opinion of our group that if the North American continent is to produce the oil to meet its requirements in the years ahead, oil from the Athabasca area must of necessity play an important role."

Digging in

The world's first large-scale production of bitumen did not mark the end of difficulties and obstacles in the development of Alberta's oil sands, it merely marked the start of a new phase in a struggle that continues nearly four decades later. There were operational problems at Great Canadian Oil Sands' mine and plant that took a quarter of a century to iron out before it became a smoothly running, reasonably profitable operation for what is now Suncor Energy. There were political and economic issues that delayed a second mining operation until public funds were invested. And when essentially all the operational problems were overcome, there remained the fact that digging can recover only about seven percent of the 1.6 barrels of bitumen buried in the oil sands. In most of the areas of deposit where the overburden is too thick to be stripped away, the bitumen must be separated from sand where it lies buried — it must be separated *"in situ,"* in place — and then pumped to the surface. Finally, there are resource constraints and environmental challenges that still face both mining and *in situ* production of the bitumen and its conversion into synthetic crude oil. But great as the number of problems might be, they are no greater than the number of different approaches, ideas and methods with which they are being tackled in scores of different research and development efforts involving hundreds of millions of dollars. Most of them might fail, but only a few successes are needed.

Great Canadian Oil Sands might have produced black oil but on the company's books it was all red ink, with losses amounting to $37 million in the first three years, $90 million after seven years. "For GCOS common shares to have any value whatsoever it is obvious that the company must have much higher prices for its products," Touche, Vincent Investment Consultants Ltd., a respected Calgary firm, declared in a study in early 1971.[19] Even if oil prices zoomed, they were expected to yield much greater benefits to other oil companies with larger reserves of conventional crude oil. Nor could expansion of GCOS' operations be expected. "It is extremely unlikely that the company could attract capital for an expanded operation, and none is envisioned," the report concluded. The GCOS mining and processing facilities seemed headed for the junkyard.

It was, indeed, higher prices that rescued the operation. "Rising petroleum prices during the 1970s helped to keep the expensive operation afloat," Suncor president Richard George later observed.[20] World oil prices were $2.55 per barrel when the mine and plant started producing in 1967, and had quadrupled to $10 in 1973, and reached a peak of nearly $45 by 1980,[21] thanks to an oil embargo by the Organization of Petroleum Exporting Countries (OPEC).

Despite the price increases, things weren't much brighter in 1991 when George, a 41-year-old Sun Oil petroleum engineer who also holds a law degree, took over the reins as president and CEO of Suncor, into which GCOS had been rolled. A fire that year caused $16 million in damages to Suncor's upgrader plant while an electrical failure in -44^{0}C cold turned a labyrinth of outdoor pipe into solid icicles with foot-thick hoarfrost, and shut down operations for 10 days, costing a further $10 million. Nor was that the first freeze-up to shut down operations: it had happened twice before, for longer periods, in earlier years. A roller coaster had sent oil prices plunging by more than $22 from the 1980 peak. And Suncor's oil sands lease had enough bitumen left to keep the operation going for only another 10 years. The future still looked far from certain.

The job of turning the operation around landed on the lap of Dee Parkinson-Marcoux, Suncor's executive vice-president. Parkinson-Marcoux arrived at Suncor the same year as George, and she, too, was an engineer, who had been in charge of Petro-Canada's refineries in Western Canada.

The company's biggest operational problems centred on its costly, inefficient, and unreliable excavators — nine-storey monster vehicles with studded bucketwheels that scooped up overburden or oil sands — and the conveyor belts that carried the oil sands to the plant for separation. Parkinson-Marcoux and her staff surveyed the world's biggest strip-mining operations where they found that giant buckwheel excavators had been largely replaced by mammoth crane-like shovels and giant trucks. Two years after George and Parkinson-Marcoux arrived, Suncor junked its four giant bucketwheels in favour of the scoop shovels and trucks with 240-ton payloads — and later, even larger trucks, the world's largest, house-size vehicles driven by 2,700-horsepower diesel electric engines that carry 360-ton loads. The switch from bucketwheels to scoops and shovels shaved costs by $5 a barrel while other improvements have cut Suncor's costs in half, making it one of the lowest-cost oil producers in North America — although still much higher than Middle East oil costs.

By 2004, Suncor had acquired new oil sands leases, opened a new mine, boosted production capacity from the original 45,000 to 225,000 barrels per day and was on target with planned further expansions to 500,000 barrels per day by 2012, including mining and *in situ* production.

While its oil sands operations have been transformed, so has Suncor's corporate structure, from a 96-percent owned subsidiary of a U.S. parent to a widely held Canadian company. Suncor was formed in 1979 when parent Sun Oil (later named Sunoco Inc.) merged its two Canadian subsidiaries, Great Canadian Oil Sands and Sun Oil Co. Ltd. The latter had been marketing petroleum products since 1917, building a chain of service stations in Ontario and Quebec and a refinery at Sarnia in 1953. Then from 1981 to 1995, Sun sold its interests in Suncor for more than $1.9 billion, in three stages. First came the sale of a quarter interest to the Ontario government's ill-fated Ontario Energy Corporation for $650-million; followed by a public offer of 20 percent to Canadian investors in 1992 for $120 million; and the sale of its final 55-percent interest to a Canadian investor group headed by Nesbitt Burns Inc. of Toronto for $1.16 billion. Ontario Energy also sold the stake it had bought in Suncor.

The sales were not timely for Sunoco, and worse for Ontario Energy. The Ontario government lost more than $300 million on its $650-million investment in Suncor. And Sunoco sold out just as Suncor was ramping up production, revenue, and profits. In 2003, Sunoco earned a profit of $406 million while Suncor earned two-and-a-half times as much, turning in a profit of more than $1 billion for the first time.

The offspring had grown bigger and more profitable than its parent. J. Howard Pew's bold and visionary gamble on the Athabasca oil sands finally paid big dividends, but the family-controlled firm failed to hang on long enough to cash in.

Oil sands and political tar

The next two strip-mining operations brought into production were Syncrude in 1978 and Shell Oil and its partners in 2003. Both experienced long periods of gestation, and for Syncrude, at least, a difficult birth midwifed with money from the Alberta, Ontario, and federal governments, which put up half the cost.

Cities Service Athabasca Inc., a subsidiary of Henry Doherty's research and conservation pioneering Cities Service Oil Co., in 1957 began the research that would lead to the start-up of Syncrude's production 21 years later. By 1959, Cities Service's pilot plant at Mildred Lake north of Fort McMurray was strip-mining oil sands with a bucketwheel excavator, extracting the bitumen, and shipping it for processing at a pilot refinery. Cities Service was later joined by Imperial Oil, Atlantic Richfield (Arco), and Royalite (which was then an independent oil producer-refiner-marketer, having been sold by Imperial but not yet acquired by Gulf Canada). When the applications of the Cities Service group and Shell were rejected in favour of final approval of GCOS, the Cities Service group was reorganized in 1964 as Syncrude, and applied again.

Syncrude won approval for its oil sands plant — more than twice the size of GCOS' initial capacity — in 1969, but that was not the end of its difficulties. Two years later, Syncrude had achieved little progress when Peter Lougheed's Conservatives swept into power, ending Social Credit's 36-year reign in Alberta. The Conservatives brought with them a new approach to energy, and especially oil sands policy that effectively put Syncrude on hold. Ernest Manning's Social Credit administration acted in the manner of a landlord, seeking to wrest as much profit as possible from its tenants, the oil companies, to whom it had leased oil and gas rights. The Lougheed government wanted to be more than just a landlord, it also wanted to be a player in the oil game.

One of the new government's first actions was to ask a group of senior bureaucrats to draft an oil sands development policy for consideration by cabinet. The 1972 confidential report advocated a strong interventionist policy and criticized Social Credit's laissez faire approach which it claimed imposed "long term costs arising from exported energy, technology, job opportunities and environmental damages, in addition to the depletion of non-renewable resources."[22] The bureaucrats advocated a policy "developed, shaped and influenced by Canadians for the benefit of Canadians," one which might "change the historical trend of ever-increasing foreign control of non-renewable resource development in Canada." The government was urged to undertake at least some of the oil sands development itself, financed in part by a proposed special levy on those to whom it had issued oil sands leases.

The government didn't walk the full length of this bureaucratic plank, but it certainly stepped in that direction with new terms under which it was prepared to allow Syncrude to proceed. Those terms were made clear during negotiations in Edmonton with Syncrude that David Wood, a Lougheed lieutenant and head of the government's Public Affairs Bureau, later characterized as "those suspense-filled days of August 1973."[23] The negotiators were Peter Lougheed and Energy Minister Don Getty for Alberta; and the chief honchos for the oil companies: Syncrude president Frank Spraggins, Jack Armstrong of Imperial, Jerry McAfee of Gulf Canada, Gordon Sellars of Cities Service, Bob Anderson of Arco, and platoons of cabinet ministers, vice-presidents, and experts.

The first meeting, involving only the vice-presidents and cabinet ministers led by Getty, was almost the last. When the Syncrude people said that the terms under which the consortium was prepared to continue were not negotiable, Getty and his group walked out of the meeting. The next day, when Lougheed outlined Alberta's terms, the oil companies were close to walking out. Lougheed wanted 50 percent of Syncrude's net profits for Alberta; a back-in option to acquire a 20 percent interest in Syncrude, after final costs and probable profits were determined following the start-up of production; and for Alberta Energy Company (half owned by the government), half ownership of the oil sands-to-Edmonton crude oil pipeline plus 80 percent of the project's large power generating plant. The pipeline and the power plant were the only aspects of the project that were almost certain money makers.

It required several more "suspense-filled days" before the oil companies caved in to Alberta's demands and Syncrude was back on track. But not for long. Sixteen months after the terms had been agreed to in Edmonton, Arco, with its 30 percent stake, pulled out of Syncrude on December 7, 1974, leaving a gaping hole that was bigger than the remaining three participants were willing to fill. In a period of roaring inflation, final cost estimates by now had doubled to $2.3 billion, Atlantic Richfield Canada's U.S. parent needed money to develop its share of Prudhoe Bay, North America's largest oil field on the North Slope of Alaska; and the U.S. Export-Import Bank had declined to finance the purchase of U.S. equipment that would be used in building the Syncrude plant. Once more, Syncrude was on the brink of collapse.

Some hurried telephone calls and discussions set up a rescue meeting in Winnipeg on February 3, involving the governments of Alberta, Ontario and Canada and the CEOs of Imperial, Gulf Canada, and Cities Service Canada. Lougheed and Don Getty were there for Alberta; Ontario sent Premier Bill Davis, and Canada sent Energy Minister Donald MacDonald. Each party had an agenda. Macdonald and Davis were gripped by the OPEC embargo that tripled oil prices in three years and threatened severe shortages. Rescuing Syncrude was viewed with a sense of national urgency. Alberta wanted to hang on to the terms it had wrung from the oil companies and, according to insider David Wood, "In order to do that, Lougheed knew, Alberta would have to put up equity."[24] The three oil companies wanted someone to fill the hole Arco had left, and it was clear that the governments would have to do that. Which they did, going on the hook for at least half the total cost. The federal government agreed to take a 15-percent stake; Alberta took 10 percent, and Ontario, five percent. In addition, Alberta loaned $200 million to Gulf and Cities Services, later converted to a 20-percent interest in Syncrude, and committed its Alberta Energy Company to put up all the costs of the pipeline and the power plant.

Three months after the Winnipeg rescue, Ottawa established its national oil company, to howls of bitter protest in Alberta. In Calgary, Petro-Canada was at first about as welcomed as a hooker at a matronly tea party. Bumper stickers would later proclaim, “I’d rather push this car a mile than fill up at Petrocan.” No one seemed to notice that it was Alberta that had the second biggest corporate interests in the oil business, in Alberta Energy, in its 20-percent stake in Syncrude, and in Nova, with its province-wide gas-gathering grid which, while not government-owned, was a tool of government policy.

Would Syncrude have flown without more than a billion dollars in government help if Alberta’s terms had been less demanding? It’s a moot point. But it’s interesting to note that Alberta’s stake in Syncrude and Alberta Energy were later sold, while Lougheed’s terms were scaled back. In December 1995, Alberta announced a new royalty deal for oil sands projects, with a basic one percent gross royalty and a reduction from 50 percent to 25 percent on profitable production, after recovery of capital costs plus a rate of return equal to the rates paid on long-term Canadian bonds. The effect was immediate, and dramatic. In seven years following announcement of the new terms, capital expenditures on oil sands development totalled $24.5 billion, nearly five times the $5.5 billion spent during the preceding seven years.[25]

Fifty-seven years after it first started exploring the oil sands, and following drilling, research, pilot projects and several regulatory applications, Shell Canada completed the third oil sands mine in 2003. The Shell group’s $3.7 billion Athabasca Oil Sands Project includes a mine and extraction plant some 40 miles north of Fort McMurray with a design capacity of 155,000 barrels a day of bitumen. The bitumen is diluted with lighter petroleum liquids so it can be pipelined to an upgrader at Edmonton where it is converted into high-grade synthetic crude oil. Shell’s partners in the operation, with 20-percent interest each, are Chevron Canada and Western Oil Sands.

In situ: fired and steamed up

There are only two ways to produce the bitumen trapped in Alberta’s oil sands. One is to mine the sands and extract the bitumen in large processing plants, as Suncor, Syncrude and Shell are doing. The other is to thin and extract the bitumen *in situ* — in place, where it lies buried mixed in the sand beneath a hundred or a thousand feet of overburden so that oil wells can pump it to the surface, as Imperial Oil and others are doing. Only seven percent of all Alberta’s oil sands can be economically mined, the province’s Energy and Utilities Board estimates; the remaining 93 percent are covered with too much overburden and must be produced *in situ* if they are ever to be recovered.[26]

Heat, steam, and solvents are the only known ways to produce bitumen *in situ,* and all three were tried during a period of 65 years in tests that might be categorized as ranging from crude to refined, before commercial success was finally achieved in 1985.

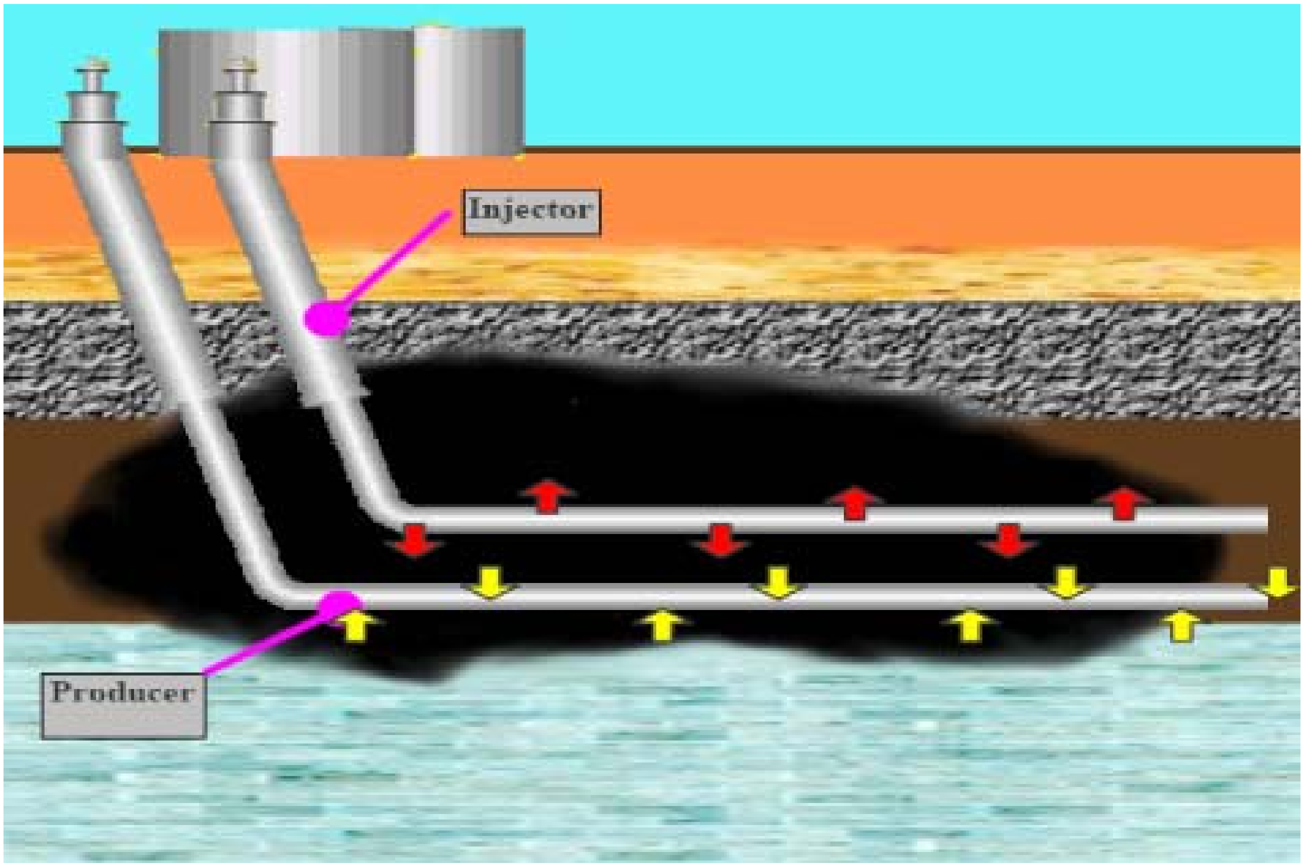
The first attempt at *in situ* production was made in 1918 by the Northland Oil Syndicate at a well drilled three miles north of Bitumount. Twelve pounds of dynamite were exploded at the bottom of the hole, followed by injection of hot steam, which resulted in pumping a mixture of liquid bitumen, sand, and water, with some of the sand settling out to the bottom of a storage tank.[27] Although no sustained production was achieved, this effort at least pointed to the right direction. Exactly 50 years later, the first successful commercial *in situ* production was achieved by means of steam injection.

Two years after the Northland test came the first “fire flood” effort to produce bitumen *in situ.* A man identified only as D. Driver built a substantial wooden derrick and drilled through the oil sands at a site near Fort McMurray. Casing was set near the base of the oil sand, to where natural gas was fed through a small-diameter pipe, and ignited. The resultant fire produced some “vapours” but no bitumen production.[28]

A second fire flood was later attempted by Montana oil man Jacob Absher for the Bituminous Sands Extraction Company, a venture of Turner Valley oil producer William Fisher. Absher first tried injecting steam down a number of shallow wells without success, then poured burning kerosene down the well. The bitumen ignited but the fire was so hot that the pipes melted.[29]

Standard Oil of Indiana in 1968, following 10 years of lab and field testing, thought its production subsidiary, Pan American Petroleum, finally had a fire flood system that could produce liquid oil from the Athabasca oil sands. At a pilot project 25 miles southeast of Fort McMurray, Pan American (later called Amoco Canada Petroleum) pumped 20,000 barrels of liquefied bitumen from oil sands ranging in thickness from 220 to 340 feet and covered with about 1,000 feet of overburden during a 16-month trial, using a method it called COFCAW, “combination of forward combustion and waterflooding.”[30] Pan American first fractured the oil sand formation by hydrafracing, a company-patented system of applying hydraulic pressure, followed by air injection, ignition of the bitumen with a catalyst, and water injection to create steam underground. The resulting mixture of water, sand, and bitumen was then pumped to the surface by a nearby well. Pan American confidently announced it would produce 8,000 barrels a day of bitumen from 75 producing and 20 injection wells, with initial commercial production to start in 1973. Later expansion to a production rate of 60,000 barrels a day was contemplated.

“After more than 10 years of research in the lab and field, we are confident that we have found the answer to producing reluctant subsurface Athabasca tars,” Lloyd Elkins, Pan Am’s director of production research in Tulsa, announced.[31]



"Steam assistred gravity drainage" (SGAD) is the method widely used in producing bitumen *in situ* from the Athabasca oil sands. Horizontal wells are drilled in pairs. Steam is injected into the oil sand through perforations in the upper pipe, separating the bitumen the sand and the mixture of bitument and water is pump to the surface. *In situ* production has less environmental disturbance than surface mining. Tests using deeply buried thermal energy to produce steam could reduce natural gas consumption in generating steam and also reduce greehouse gas emissions. Other pilot tests involving the use of solvents and partial underground combustion of the bitumen might also reduced greenhouse gas emissions.

Not quite. For whatever reason, COFCAW didn't work as successfully as anticipated, and Pan American shelved the project. The facility was later taken over for further tests by the Alberta Oil Sands Technology and Research Authority as part of a $1-billion research program by the government and industry consortium.

The most spectacular fire flood idea occurred to M.L. Natland of Richfield Oil Corporation in 1957 in Saudi Arabia, as he watched the setting sun which, he later wrote, "looked like a huge orange fire-ball sinking gradually into the earth."[32] The sunset reminded Natland of a nuclear explosion, causing him to wonder why the intense heat generated by such a blast could not be harnessed to cook the bitumen out of the oil sands. Richfield and its partners carefully worked out plans to set off an experimental nine-kiloton nuclear explosion at a depth of 1,250 feet at a site 64 miles south of McMurray. The plans were studied and approved during 1958 and 1959 by the U.S. Atomic Energy Commission and by special technical committees established by the Alberta and federal governments. But in the end, final approval was withheld by the federal government because of an international moratorium on nuclear testing.

One of the great virtues of the petroleum industry is that there are so many players pursuing different ideas, only a few of which need to succeed to make notable, and sometimes stunning, progress. Thus in the oil sands, while some pursued fire floods, others continued with the steam injection approach first tried by Northland Oil in 1918, and with solvent extraction.

Shell Canada, in 1957, claimed to have achieved "the first . . . *in situ* recovery to give significant oil production from the Athabasca oil sands,"[33] at a pilot test 40 miles north of Fort McMurray. In an area where the bitumen is covered with less than 200 feet of overburden, Shell had injected 800 barrels of a synthetic detergent and produced an emulsion of oil and water from a well 26 feet away from the injector well. In expanded tests during a six-year period, Shell injected steam and detergent in five closely spaced injection and production wells, achieving peak production rates of 90 barrels of oil per day. Shell expected to recover 50 to 70 percent of the oil in place, "far greater than that obtainable in conventional oil fields." A group of Shell's researchers concluded that "a process has been developed that can successfully produce oil by an *in situ* process" while "drilling and geological studies have shown the existence of oil-in-place of sufficient continuity and volume to support a commercial-sized operation."[34]

The first commercial *in situ* production of bitumen was, indeed, achieved by steam injection, but at the Cold Lake, not the Athabasca oil sands deposit. On leases with an estimated 44 billion barrels of oil in place, Imperial Oil began tests in 1964 on what has been called the "puff and huff" method, alternately puffing down steam and chemicals and huffing up an emulsion of oil and water. Imperial started with a four-well pilot program, later expanded to a 23-well pilot test, then a 56-well program, and in 1979 applied for Alberta's permission to build a $7-billion, 135,000-barrels-per-day in situ plant and upgrader to convert the bitumen into light, synthetic oil. But Imperial shelved this with the advent of poor economic conditions and a wrangle between the Alberta and Canadian governments over energy policies and taxes that followed the 1980 National Energy Program.[35] Imperial later revived operations at Cold Lake, and early in the 21st century was producing more than 100,000 barrels of oil per day from its rich Cold Lake leases.

The biggest breakthrough in *in situ* production was made possible by horizontal well drilling, which became commercially viable only in the late 1980s,[36] and has since been enormously improved. In the latest directional or horizontal drilling technology, the 30-foot sections of steel drill pipe used in conventional drilling to rotate a drill bit are gone. They are replaced by flexible coiled tubing that does not rotate but connects with downhole, hydraulically powered motors that rotate steerable drill bits. A horizontal well is typically first drilled vertically to just above a desired depth then sharply angled to quickly attain a horizontal direction. The downhole motor and drilling bit can be steered up, down or sideways with precision using information from downhole sensors that is telemetered to the surface. Horizontal drilling can extend for surprising distances: in 2003, BP Amoco "drilled a virtually horizontal well from onshore in Britain out into the English Channel for 6.3 miles to recover about 15,000 barrels of oil per day."[37]

With horizontal drilling, the first big *in situ* breakthrough came in 1991 with an announcement of pilot test results of a new process by the Alberta Oil Sands Technology and Research Authority (AOSTRA), a joint government-industry undertaking that had spent 18 years and $1 billion researching and testing various ways to recover and refine bitumen. At a "proof of concept pilot underground test facility" 37 miles north of Fort McMurray, AOSTRA had demonstrated a method called "steam-assisted gravity drainage" (SAGD) that enables *in situ* production of the oil sands at a cost comparable to the cost of new supplies of conventional crude oil.

The technology is complex, but the concept is simple. In the pilot test, a series of twin wells were drilled vertically and then, with a sharp 45-degree bend, drilled horizontally for a distance of 1,968 feet through oil sands, one above the other, spaced 16 feet apart. Piping-hot steam was injected at high pressure through the top well, heating the bitumen enough to flow down into the lower well bore, from which it was pumped, together with water, to the surface. A dozen twin wells were drilled and equipped at the test facility, each pair spaced 230 feet apart. The SAGD method was designed to produce from oil sands that are at least 50 feet thick and covered with more than 230 feet of overburden. That encompasses most of Alberta's oil sands deposits.

Based on the results of the pilot test, in which more than 100,000 barrels of bitumen were produced, AOSTRA estimated that the SAGD process could recover 60 percent of the oil in place at suitable oil sands sites, at a cost of about US$11 per barrel.

Progress and problems

Production of Alberta's oil sands was expected to approach one million barrels of oil a day in 2004 and more than double that early in the century's second decade, with new and expanded facilities that were actively underway. By then, oil sands production was expected to total about 800,000 barrels a day of steam-driven *in situ* production and about 1.8 million barrels a day from mining operations, not including planned projects that had not actually got underway by 2004.

But big challenges still confronted the growth of oil sands production, including emission of greenhouse gases, massive requirements for water and fuel, and environmentally safe disposal of billions of tons of mined sand, plus tailings from the hot water separation plants. Fortunately, tens of millions of dollars were also being spent in research and development of new *in situ* methods which, if successful, could go a long way to resolving these challenges.

The size of the challenges can be quickly sketched.

•Fuel. Oil sands are fuel hogs. Generating steam to recover one barrel of raw bitumen in the SAGD production process requires about 1,000 cubic feet of natural gas. Upgrading bitumen to synthetic crude oil requires about another 750 feet of gas.[38] That doesn't include the fuel used by the giant scoop shovels and the sand-and-bitumen separation process in mining operations. These figures suggest that projected oil sands production of 2.6 million barrels a day by 2015 would burn up gas at a rate of almost three billion cubic feet a day, about one-fifth of Canada's total gas production. Gas consumption could be reduced by using the bitumen itself or upgraded bitumen products for fuel. Either way, it's a lot of fuel.

• Greenhouse gases. Upgrading raw bitumen into synthetic crude oil — a blend of naphtha, kerosene, and gas oil (similar to diesel fuel) — involves the removal of carbon, the addition of hydrogen (derived from natural gas), and removal of impurities. The process results in the emission of substantial greenhouses gases, primarily carbon dioxide and small amounts of methane. Burning natural gas to produce steam for *in situ* production also results in the emission of carbon dioxide. In 1990, each barrel of oil sands production resulted in emissions amounting to the equivalent of more than 100 kilograms of carbon dioxide.[39] Processing improvements have cut this in half, but total emissions have still increased with the rapidly growing volume of oil sands production. Emissions of nitrogen oxides and sulphur dioxides from oil sands production also impose environmental challenges.

By far the greatest emission of greenhouses gases, however, comes not from producing oil, but from using it. For every ounce of carbon dioxide emitted in producing a barrel of oil from the oil sands and refining it into finished products, four or five times as much is emitted when cars and trucks burn it as gasoline or diesel fuel or in other uses.

• Land disturbance. About two tons of sand are left to be disposed of for every barrel of oil produced in mining the Athabasca deposit. Close to four million tons of sand will have to be returned to mined-out areas each day by early in the century's second decade. By returning previously removed muskeg and topsoil together with replanting trees and shrubs and by other measures, oil sands miners have successfully restored mined-out areas to at least their original state of biological productivity, but it is not a small task. Water and clay from the water separation plants dumped into tailing ponds also have a potential impact on water quality that "does not lend itself to . . . easy solutions," according to the Canadian Association of Petroleum Producers.

•Water consumption. About 80 percent of the water used for steam in *in situ* production is recycled, and most 40 of the remaining 20 percent is absorbed by the ungrounded sand. The net result is that about one barrel of water is consumed or lost underground for every barrel of *in situ* oil production and upgrading. Thus by early in the next decade, water consumption for SAGD *in situ* production is likely to exceed 200,000 barrels a day, with the possibility of increasing volumes thereafter.

Cost, rather than technology, is likely to be the only constraint on the ability to meet these and other challenges confronting oil sands development. Innovators are gambling hundreds of millions of dollars that research and development will yield commercially economic solutions. Every obstacle that had earlier faced oil sands developers was slowly overcome during the past century, step by step. There is no reason to believe that current challenges will not similarly be met. The major difference now is that with advanced technology such as computer-simulated models, the answers to technical problems come much, much faster.

Two pilot *in situ* projects launched in late 2003 and in 2004, each costing a projected $30 million could by themselves, if successful, overcome many of these challenges. One involves the use of solvents to extract the bitumen, the other uses fire flooding. Both are based on the hope that horizontal drilling will do for these methods what it did so spectacularly for the use of steam to extract the bitumen underground.

John Wright, CEO of Calgary-based Petrobank Energy and Resources Ltd., told *Oilweek* that he is "highly optimistic" that the two-year fire flood project south of Fort McMurray "has the potential to revolutionize the heavy oil industry on a global basis."[41] Dubbed THAI, for "toe-to-heel air injection," initial work on this concept of fire flooding began in 1993 while the pilot project follows $4 million spent in 2003 by Petrobank on computer-simulated models. Potential benefits include the fact that no fuel other than the bitumen itself will be needed to produce steam. THAI is expected to burn 10 percent of the bitumen in the sand, and recover up to 80 percent. It will involve far less surface disturbance than mining, with no sand nor tailings from a separation plant to be disposed of. The underground combustion is expected to burn the carbon, sulphur, and other impurities, eliminating the need for surface processing facilities to handle this aspect. Carbon dioxide emissions are expected to be reduced by 20 percent compared with either *in situ* or mining operations, and further reductions might be achieved by returning the carbon dioxide into bitumen-depleted sands, rather than venting it into the air. The pilot project, which received Alberta approval early in 2004, is being conducted by Petrobank subsidiary Whitesands Insitu Ltd.

Another $30-million *in situ* pilot program, in which propane and other vaporized solvents are being used to thin the bitumen and wash it from the sand so that it can be pumped to the surface, began operating late in 2003. Called VAPEX, it is claimed that the system could reduce carbon dioxide emission by 85 percent as well as reduce water consumption and possibly fuel requirements.[42] The pilot program, which is to operate for a period of five to 10 years, will use the Underground Test Facility at which AOSTRA developed the SAGD *in situ* method more than a decade earlier. Financed 50 percent by the Alberta and Canadian governments, 50 percent by half a dozen oil companies, the program is being conducted by Devon Canada Energy.

Research and development programs, such as VAPEX and Whitesands, aimed at overcoming economic, environmental, and resources challenges to unlock more of the world's largest oil deposits in the Alberta oil sands, could have far-reaching global impact, as the world's largest store of oil becomes increasingly accessible.

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