AN OVERVIEW ASSESSMENT OF *IN SITU* DEVELOPMENT IN THE ATHABASCA DEPOSIT

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ALBERTA OIL SANDS ENVIRONMENTAL
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1. INTRODUCTION

The Alberta Oil Sands Environmental Research Program (AOSERP) has a mandate to gather and make available information that will aid in ensuring an acceptable quality of the environment during and after operations for recovery, transport, and processing of oil sands products. The research is directed to the practical solution of environmental and social problems resulting from oil sands development.

During the first stage of commercial development the technology for exploiting this energy resource consists of strip-mining the oil-bearing sand and extracting the oil from the sand with a hot water wash-flotation process. Thus, the strip-mining process and its effects have been the primary focus of AOSERP research efforts.

However, of the total oil in place in the oil sands deposits, less that 10% can be exploited by open pit mining technology given present economic constraints.

A second technique of extracting the resource, without removal of overburden and oil-bearing sand, is in the experimental stage, with commercial application now proposed. This method involves removing the bitumen *in situ* or in place by means of thermal and non-thermal techniques, which reduce the viscosity of the oil, enabling it to be pumped to the surface through wells.

The application of the *in situ* method of extracting the resource requires a different mix of inputs, such as a heat source and water, and produces discharges of possible effluents of different quantities and qualities.

The purpose of this project is to provide AOSERP with a preliminary understanding of the state of the art of *in situ* or "in place" bitumen recovery technology, the most probable application and rate of application of that technology to the Athabasca deposit, and the resultant implications on the environment and people of the area. This "first cut" overview of probable *in situ* based oil sands development is aimed at providing insight and general direction to research scientists responsible for meeting the research mandate set for AOSERP by the Governments of Alberta and Canada.

This report outlines the oil sands deposits in Alberta generally, and in the AOSERP study area in particular, that are of significance with reference to *in situ* technology. The various techniques advanced for *in situ* development are discussed and an assessment is made of probable commercial exploitation of the most promising techniques. A possible development scenario is outlined and an environmental impact assessment matrix is used for assessing the nature, magnitude, and implication of impacts of development upon the Land, Water, Air, and Human systems of the region.

The concluding section highlights deficiencies in the data base and suggests priority areas for research relevant to the objectives of AOSERP.

2. ALBERTA HEAVY OIL DEPOSITS AND THE AOSERP STUDY AREA

2.1 HEAVY OIL DEPOSITS IN ALBERTA

The better known heavy oil deposits of Alberta are found in the lower Cretaceous formations and are commonly identified as the Cold Lake, Peace River, Wabasca, and Athabasca deposits, as outlined in Figure 1. In addition, heavy oil or bitumen is present in the Paleozoic formations throughout northern Alberta and will require some form of *in situ* extraction technique for exploitation. The relative magnitude of the crude bitumen reserves by Cretaceous and Paleozoic age deposits and probable recovery techniques, given contemporary recovery economics, is reproduced as Table 1 (from Outtrim and Evans 1977). Similarly, Figure 2 shows the relative size of the four major deposits in terms of reserves and probable extraction technique.

The Athabasca deposit, which is the largest deposit and the only deposit partially amenable to strip-mining, is the focus of AOSERP efforts. Thus, although the Athabasca deposit and its exploitation by *in situ* means is the primary focus of this report, it is important to keep the following points in perspective:

1. Since the advent of the Alberta Oil Sands Technology and Research Authority (AOSTRA), there has been a rapid increase in the activity in Alberta's oil sands, and research on *in situ* technology is underway in all major deposits. There is an element of uniqueness about each deposit; however, the general technology is assumed by the authors to be transferable between deposits.
2. The actual rate of development of *in situ* extraction plants will be inter-related so that development in one area may preclude development in another area because of capital, labour, or market limitations.
3. The Athabasca deposit will probably not be the first deposit exploited commercially by *in situ* means.

2.2 THE AOSERP STUDY AREA

The AOSERP study area, as outlined in Figure 3, covers about 11,000 square miles, slightly over half of which is underlain with oil sands. The overburden depth covering the Cretaceous oil

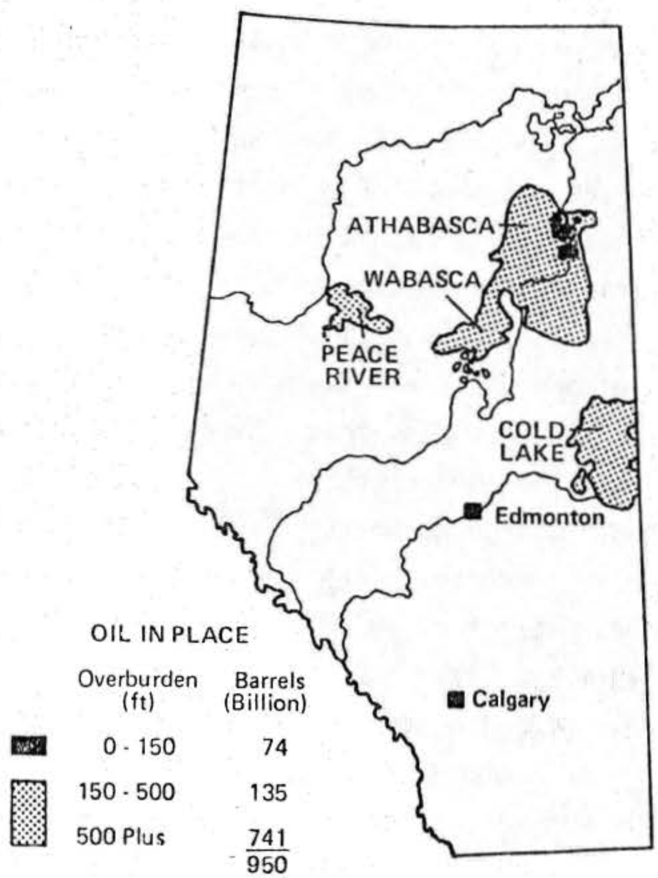

Figure 1. Major Alberta oil sands deposits.

Table 1. Ultimate recoverable reserves of crude bitumen and synthetic crude oil (from Outtrim and Evans 1977:57).

ULTIMATE RECOVERABLE RESERVES OF CRUDE BITUMEN AND SYNTHETIC CRUDE OIL
$10^9 m^3$

	Method	Crude Bitumen	Synthetic Crude Oil	Remarks
CRETACEOUS	Surface Mining...........	5.8	4.3	"PROVED" Commercial plants operating.
CRETACEOUS	In Situ Steam Flooding*..	37.2	27.9	"PROBABLE" Theoretically evaluated — No commercial exploitation.
CRETACEOUS	In Situ Non-Steam.......	9.8	7.3	"POSSIBLE" No detailed evaluation of recovery method
PALEOZOIC	All In Situ Methods.......	10.0	7.5	"POSSIBLE" No detailed evaluation of in place reserve or recovery method.
	Total Economically Recoverable Reserves....	62.8	47.1	"ULTIMATE"
	(Percent of Total In Place Reserves of Crude Bitumen).................	(15)	(11)	

*Thermal Ratio cut-off of 3

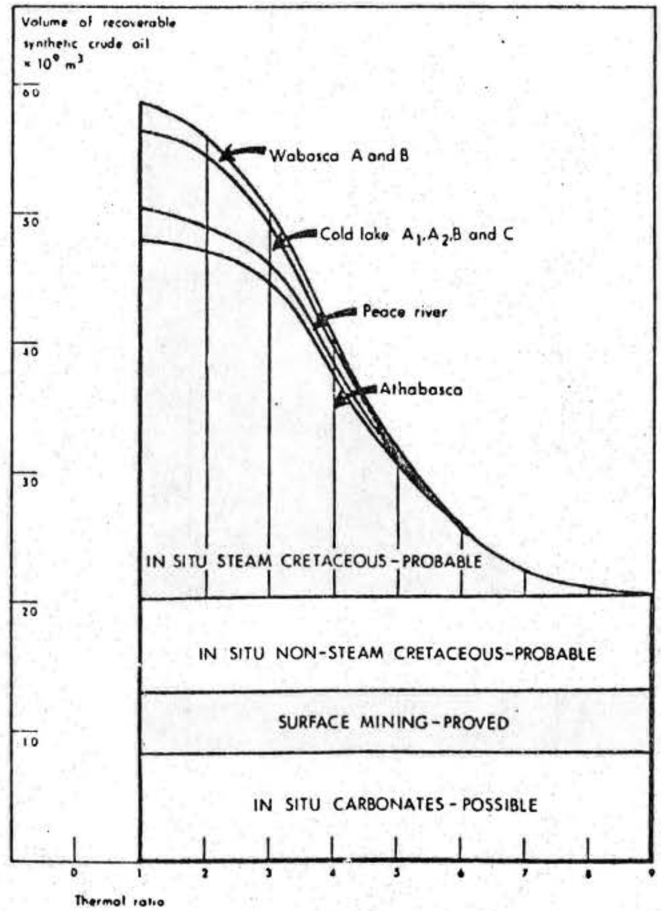

Figure 2. Proved, probable, and possible recoverable synthetic crude oil (from Outtrim and Evans 1977:66).

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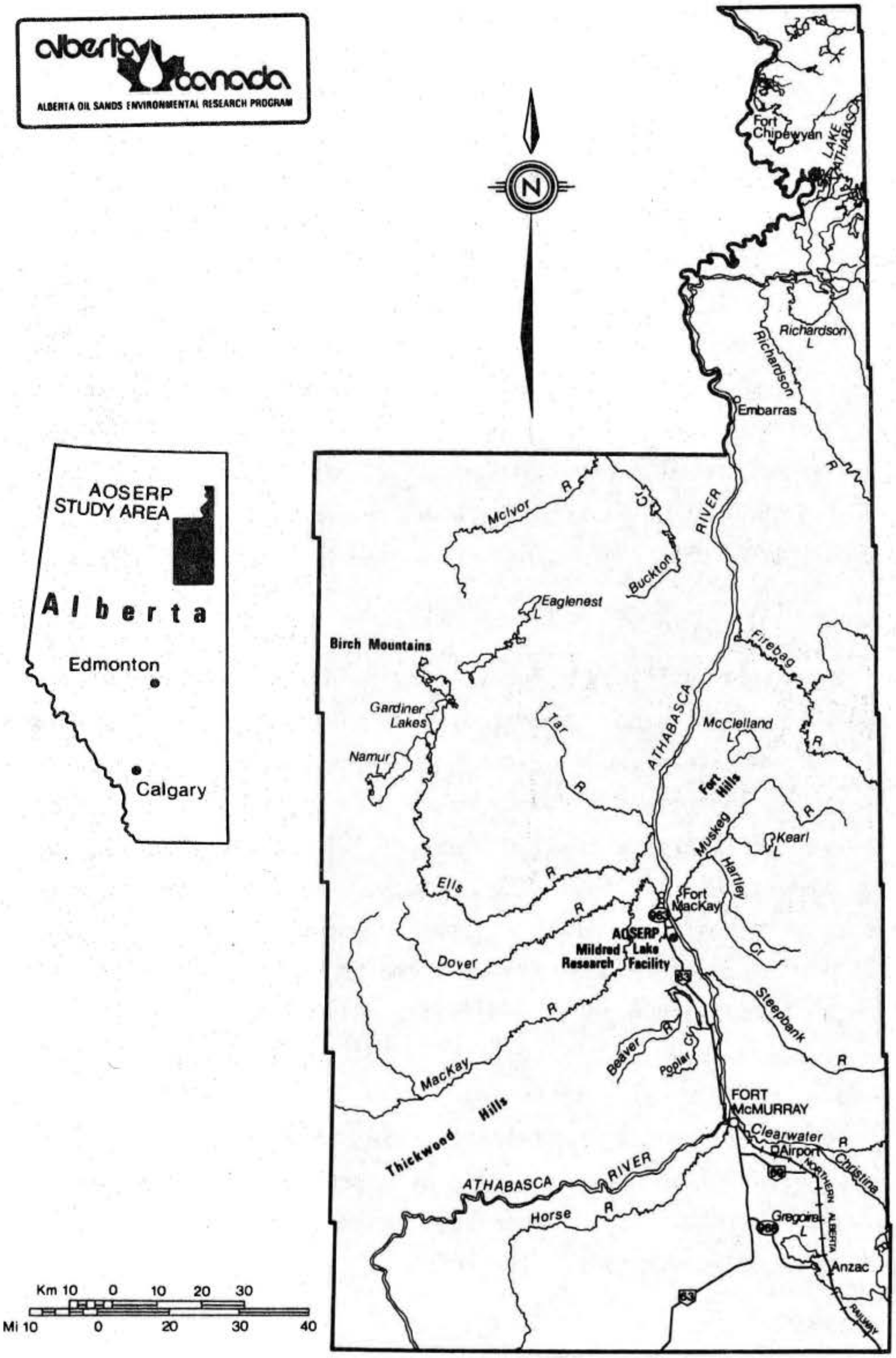

Figure 3. Alberta Oil Sands Environmental Research Program study area.

sands varies from zero, where surface outcroppings of oil sand appear, to a maximum of 2,000 feet. The popular assumption has been that *in situ* technology is limited to areas where the overburden depth is 500 feet or more in order to withstand the high pressures required for fluid drive of the bitumen. This is true only to a limited extent and for certain technologies. The off-setting factor is that the difficulty of establishing the required horizontal fracturing or communication within the oil sand zone increases with depth.

It is, therefore, easier and more appropriate to establish the limits of the probable surface-mineable area, bearing in mind that even those areas may not be the exclusive domain of the surface-mining extraction technique. The work done by Outtrim and Evans (1977) on surface mineability factours outlines the general constraints to the areal extent of strip-mining.

2.3 SUMMARY

Heavy oil is a relative term. For this report heavy oil encompasses those deposits that will require exploitation by mining or *in situ* recovery techniques beyond those presently used in secondary and tertiary recovery methods of conventional oil fields.

There are reserves of heavy oil in both Cretaceous and Paleozoic age formations. The Cretaceous sand reserves form the four major deposits in Alberta commonly known as oil sands. The Paleozoic carbonate reserves, which are found at greater depths throughout northern Alberta, are not completely delineated; they potentially add 20% to Alberta's heavy oil reserves and will have to be exploited by *in situ* technology.

There are no fixed limits based upon depth of overburden to the potential application of *in situ* technology. There are, however, limits that can be ascribed to surface-mining opportunities given present economics and technology.

3. *IN SITU* BITUMEN RECOVERY TECHNIQUES

3.1 INTRODUCTION

Conventional oil recovery methods cannot be applied to bitumen largely because it is too viscous to flow. Athabasca bitumen has an A.P.I. gravity of about 10, as opposed to a range of 30 to 40 A.P.I. gravity in conventional Alberta crude oils. The relationship of viscosity in centipoise expressed as a function of density is shown on Figure 4.

Hence, the essence of *in situ* recovery is to overcome the bitumen's natural resistance to flow. Once the bitumen is brought to the surface, the task of upgrading to synthetic crude oil is essentially the same as that for bitumen extracted by surface mining and separated from the sand by the hot water wash/flotation process.

3.2 HEAVY OIL AND BITUMEN RECOVERY TECHNIQUES

Bitumen may be described as a very heavy, black crude oil with a density heavier than that of water. The bitumen deposits of Alberta differ from conventional oil deposits in two ways: (1) the physical properties of bitumen are very different from those of conventional crude; bitumen has a small concentration of low molecular weight hydrocarbons and a high concentration of high molecular weight polymers; and (2) the deposits or reservoir have no natural drive energy which can be used to produce the oil in the conventional manner.

As the bitumen is very viscous, any *in situ* recovery process must significantly alter the native reservoir conditions to induce flow. The constraints which must be overcome to apply *in situ* recovery processes to the oil sands are: (1) the bitumen must be made mobile to allow displacement as it is too viscous to flow naturally; (2) the oil-saturated sands lack the required communication between injection and production wells; and (3) the reservoirs lack a natural drive mechanism which must be supplied to produce the oil.

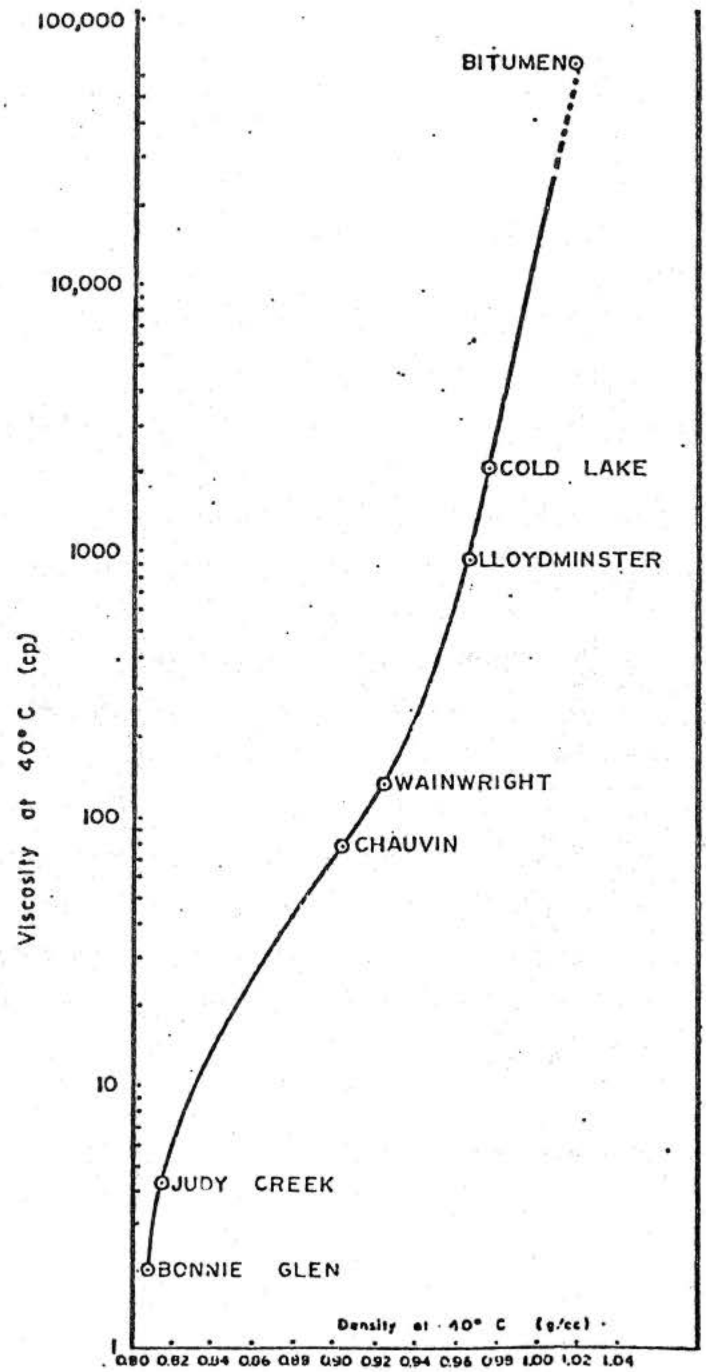

Figure 4. Centipoise viscosity--density relationship--Alberta heavy oils (from: Elmayergi and Flock n.d.).

A reduction in viscosity may be accomplished by the application of heat or by contacting the oil with suitable solvents or emulsifying agents. Communication between injection and production wells may be achieved by fracturing the formation, making use of a high permeability zone, or by using underlying zone of water sand. The driving force can then be supplied by the injection of fluids. Once the viscosity reduction and well communication have been established the injection of a fluid forces the liquified bitumen to and up the production well.

The recovery processes under study are listed in Figure 5. The *in situ* methods may be subdivided into two types, thermal and non-thermal. These various methods can be used singularly or in combination.

Thermal recovery methods involve the application of heat to raise the temperature of the oil-bearing formation, which reduces the viscosity of the oil dramatically, thus improving the mobility of the oil. The response of the viscosity of some fluids to temperature at atmospheric pressure is shown in Figure 6.

Non-thermal methods such as the use of diluents, emulsifiers, and bacteria lower the density and, hence, lower the viscosity of the native bitumen. Figure 4 shows the dependence of viscosity with density.

3.3 RECOVERY PROCESSES

Below is a brief description of the thermal and non-thermal techniques currently under research or in the pilot plant stage of development.

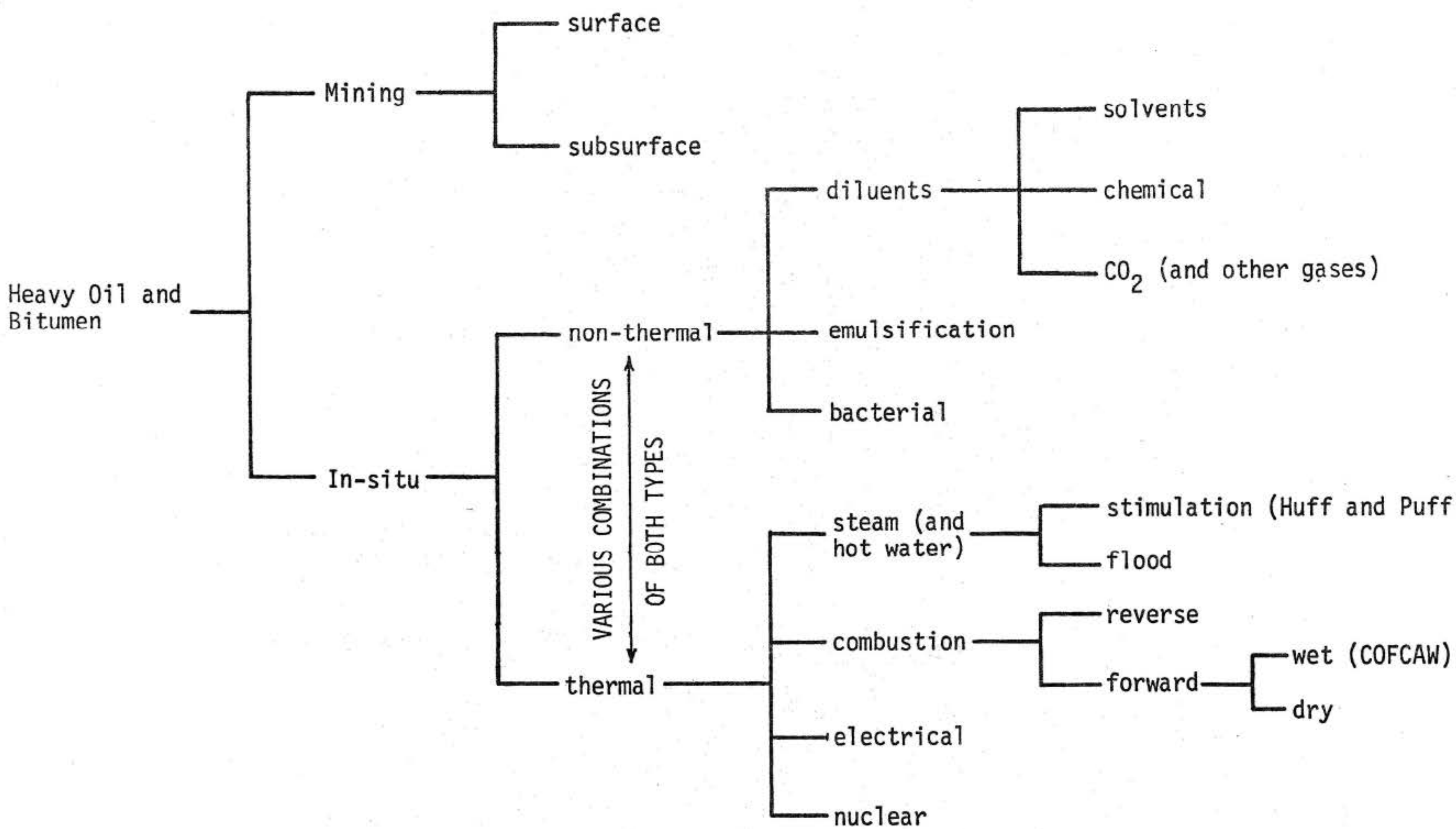

Figure 5. Heavy Oil and Bitumen Recovery Techniques.

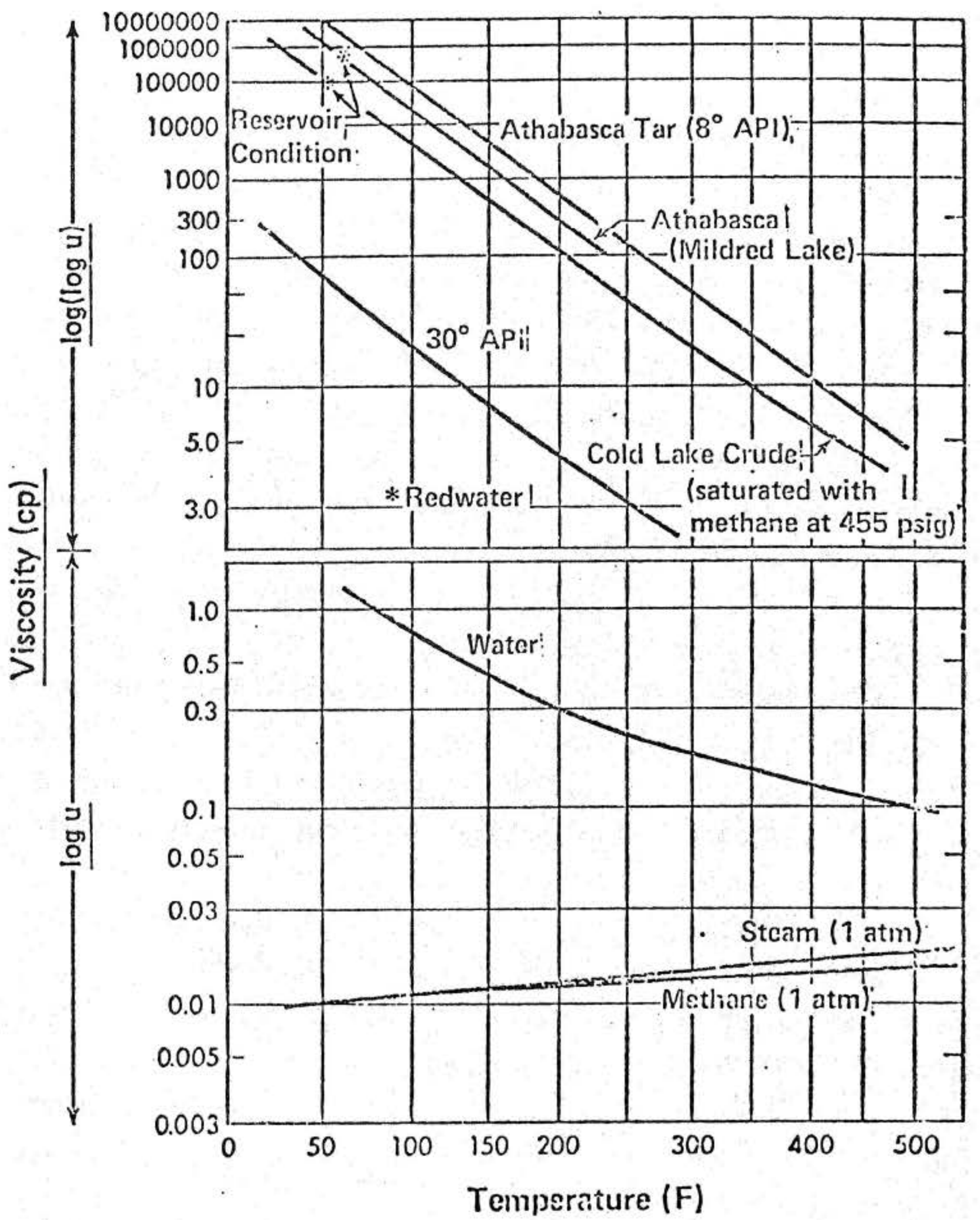

Figure 6. Temperature--viscosity relationship (from: Oil Sands Technology and Economics 1977).

3.3.1 Thermal Methods

3.3.1.1 Steam injection.

3.3.1.1.1 Cyclic steam stimulation. The cyclic steam injection process is commonly called the "Huff and Puff" method. This is a process in which steam injection and fluid production take place in the same well. In the first phase, a specific quantity of steam is injected into the formation for a period of time, generally from 4 to 8 weeks. The injection phase is generally followed by a short "soak-in" period to allow the pressure and heat to partially disperse throughout the reservoir. This application of heat reduces the viscosity of the bitumen. The last stage then involves the production of liquified bitumen back through the same well. The driving force is some combination of solution gas drive, gravity forces, and pressurization due to the steam injection. The production phase may last 3 to 6 months, at which time the production rate has reached a pre-determined level dictated by economic limits. The cycle is then repeated until the current produceable bitumen in the vicinity of the well is depleted. Tests indicate a well may have an economic life lasting from 6 to 8 years.

The "Huff and Puff" process is a stimulation technique, and is a primary recovery process for heavy oil deposits. Parameters which must be considered are reservoir thickness, fluid distribution, and the depth of the reservoir.

The number and duration of cycles which may be employed depend on the quality of the reservoir, volume and rate of steam injected, and the temperature and quality of the steam.

3.3.1.1.2 Steam drive. In the steam drive or steamflood process, steam is injected into wells on a pattern basis with the oil/water fluids being produced at different wells. As the steam heats the oil, the viscosity is lowered and the oil is able to move toward the producing well. In this case, the steam provides the major driving force of the bitumen to the production well.

A modification of the above is the cyclic steamflood process used when the oil sand is underlain by a water-bearing formation. The cycle consists of three phases: firstly, the formation is heated by conduction when steam is injected through the water zone; secondly, the production wells are then shut-in partially to pressurize the formation; and thirdly, in the final blowdown phase, the production is continued to some pre-determined rate and then the cycle is repeated.

The capacity of the oil sands formation to accept steam is very small and, hence, the reservoir may require: (1) some preheating by another method (combustion, electrical energy), or (2) horizontal fracturing if the reservoir is at a sufficient depth to contain the applied fracturing pressure. The injection rates during steamflooding must be monitored to avoid early steam breakthrough (at too high rates) or excessive heat losses (at too low rates).

3.3.1.1.3 Steam drive versus cyclic steam stimulation. From the results of extensive testing it was found that the oil: steam ratio is much higher for cyclic steam stimulation, whereas the ultimate oil recovery is likely to be much greater for the steamflooding process.

Steam injection, to date, is the only method which has, in other parts of the world, proved to be successful commercially to recover heavy oils. The "Huff and Puff" process should continue to yield good results, particularly if supplemented with steamflooding.

3.3.1.2 *In situ* combustion. *In situ* combustion is a multi-well displacement process which involves heat transfer with phase change and chemical reactions coupled with multiphase flow through the reservoir. There are three variations of *in situ* combustion: (1) dry forward; (2) wet forward, or combination of forward combustion and waterflood (COFCAW); and (3) reverse combustion.

3.3.1.2.1 Dry forward combustion. This process may be described as follows. Air is injected into the formation to establish communication and a continuous gas phase between injection and production wells. Heat is then introduced to preheat the vicinity of the wellbore of the injection wells. A down hole fire is initiated by using an igniter device when the temperature increase is sufficient. A portion of the oil in-place is used as fuel. Air injection is continued to drive the burning zone toward the production well. The resulting heat lowers the viscosity of the oil and the injected air and combustion gases can displace the oil.

When stability is reached, the process may be described by the following series of zones: a burned zone, a combustion front, a hot water zone, a light hydrocarbon zone, an oil bank, and, finally, an unaltered zone. The displacement mechanism acting on the oil that has not been contacted by the combustion front is some combination of condensing steam drive, miscible drive, and thermal drive.

The process is restricted by the thickness of the reservoir; if a critical thickness is exceeded, there is a tendency for the air to override the fluids and bypass the combustion front. As with other displacement type processes, it is desirable to first have good horizontal continuity.

3.3.1.2.2 Wet forward combustion (COFCAW). In the dry forward combustion process most of the heat which is generated is lost to the overburden and, also, left behind in the burned zone.

The COFCAW process is initiated in the same manner as the dry forward combustion process. Water is then injected simultaneously with air through the burned zone, converting the water to steam, thus utilizing the heat left behind by the combustion front. The steam flows through and ahead of the front. This results in lower temperatures in the burned zone and higher temperatures ahead of the front combining the advantages of dry combustion and steamflooding.

The air requirements of this process are less than dry combustion and less of the in-place oil is consumed as fuel. Because of a more favourable mobility ratio of the fluids present, the areal sweep efficiency is improved.

3.3.1.2.3 Reverse combustion. Combustion in the reservoir is achieved in the same manner as before. Then, the process is halted temporarily and the flow of air is reversed, causing the combustion front to move counter-current to the air flow. The heated oil then moves through the pre-heated burned zone, giving a significant decrease in oil viscosity.

The air requirements for reverse combustion are higher than for forward combustion and ultimate recovery potential is lower; hence, this is the least desirable of the combustion techniques and will most likely be used only when other methods prove impractical.

3.3.1.2.4 Steam injection versus *in situ* combustion. The combustion process is well suited for moderate viscosity reservoirs with a high oil saturation and good porosity and permeability, whereas steam injection is better if the viscosity is high. In terms of fuel costs, surface-generated steam will be a more expensive input than the air input cost of a combustion process.

Because the steam injection process has added heat losses in the wellbore, combustion is better suited for deep reservoirs. The major handicaps of combustion recovery are problems associated with the subsurface movement of gases and control of the combustion front propagation.

3.3.1.3 Electrical. *In situ* recovery by electricity is based on the concept of heating by resistance or Joule heating. The fundamental requirement is that the formation have a high electrical conductivity.

A large A.C. current is conducted down the wellbore, through the deposit, and back up an adjacent well. This results in heating throughout the reservoir, including the important centre point between the wells.

Once the creation of a mobile path between the wells has been achieved, the oil can then be recovered by a fluid displacement process, i.e., by steam drive or combustion.

The economic viability of this process is strongly affected by the efficiency with which the expensive electrical energy is transmitted down the wellbore and the percentage of applied power which actually contributes to increasing the formation temperature.

3.3.1.4 Nuclear. It has been proposed that, when considerable overburden exists, a nuclear device be detonated in the wellbore to supply heat locally around the injection well. Estimates of released energy, crushed zone, and minimum overburden were based upon tests in Nevada where the oil sands formation are quite different; therefore, large errors may exist in these estimates. Because of the overburden requirements of approximately 1,000 feet, this process would have limited applicability in the AOSERP study area.

This technique is not useable today because of the potential environmental hazards, high cost of purchasing and handling of the device, and public outcry associated with nuclear power. It should be noted that comparable quantities of energy can be delivered to the reservoir by steam or combustion more easily and cheaply today by the techniques described above. Perhaps in the future the use of small devices at shallower depths than 1,000 feet may be possible as the cost of steam and combustion operations increase. Nevertheless, use of nuclear energy is limited to the local heating of the wellbore and will have to be supplemented by a displacement process.

The use of nuclear energy may be applied indirectly in the form of nuclear-fired power stations to meet the energy requirements of the recovery/processing plants. Figures 7 and 8 illustrate the steam drive and the *in situ* combustion processes, which are major *in situ* recovery processes. Figures 9 and 10 illustrate the electrical heating and nuclear explosion techniques.

3.3.2 Non-thermal Methods

The use of diluent, emulsifiers, and bacteria have been proposed as means to increase the mobility of the bitumen.

3.3.2.1 Diluent flooding. The basic types of diluents are: (1) solvents (e.g., propane butane with methane, water, alcohols), (2) chemicals (e.g., alkalines), and (3) carbon dioxide. The addition of diluents will be effective in achieving a large reduction in viscosity, especially if used with heat.

Recovery using diluents involves the injection of a slug or volume of liquid into the deposit to dissolve or dilute the bitumen to form a solution with a decreased viscosity. The diluent used should be miscible with the bitumen and, to be effective, must also come in direct contact with the oil. It has been found that, since large quantities of diluents would be required and, also, large losses to the formation would occur, the exclusive use of diluents would not be economic.

3.3.2.2 Emulsification. The emulsification process requires the injection of a series of fluids into a reservoir. Initially, a slug of micellar solution (formed by the dispersion of a surfactant in a solvent to form a water-in-oil or oil-in-water emulsion) is injected, followed by a less expensive fluid termed a mobility buffer. The mobility buffer is a polymer-water solution and is used to displace the initial slug. Finally, water is used to displace the previous fluids toward the producing wells.

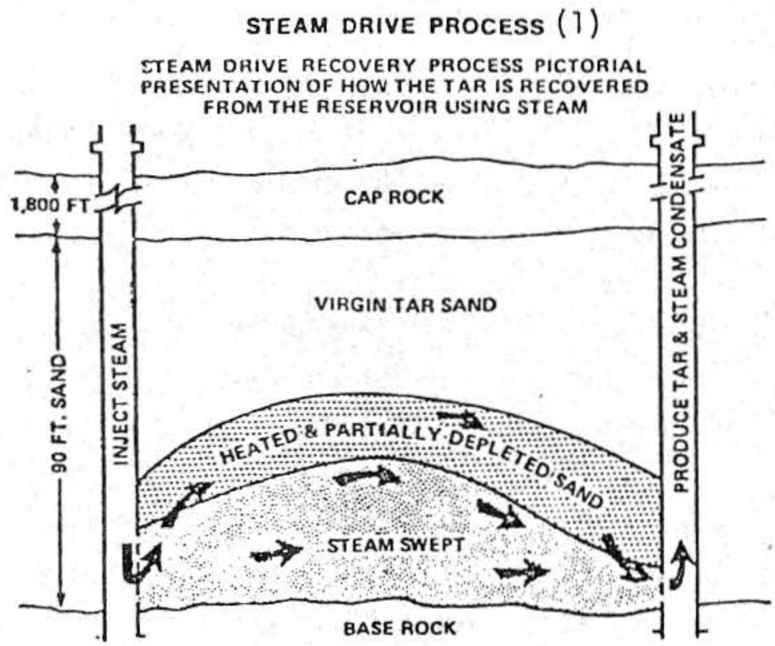

Figure 7. Steam drive process (from Malden 1977).

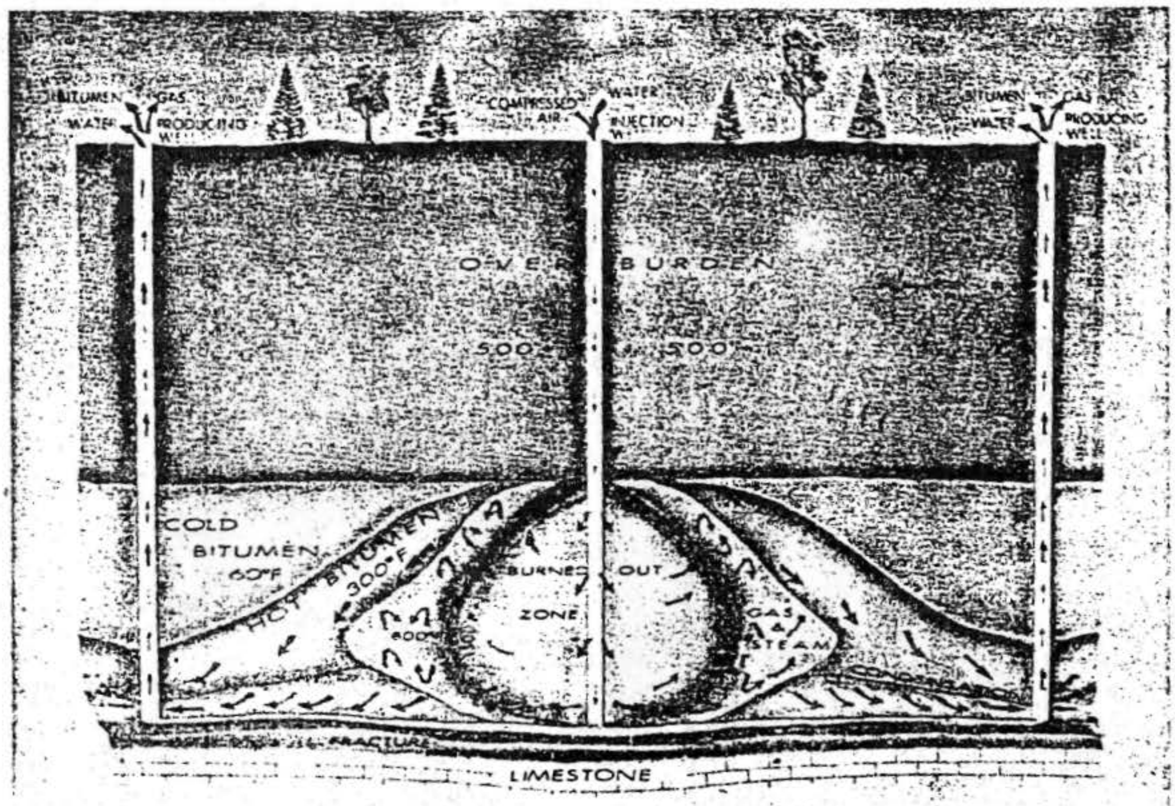

Figure 8. *In situ* bitumen recovery by underground combustion (from Intercontinental Engineering of Alberta 1977).

Can. Pat. No. 1001550: A METHOD FOR PRODUCING BITUMEN FROM A SUBTERRANEAN TAR SAND FORMATION

STEP 1 - ELECTRICAL HEATING TO MOBILIZE BITUMEN

STEP 2 - FLUID DRIVE TO PRODUCE BITUMEN

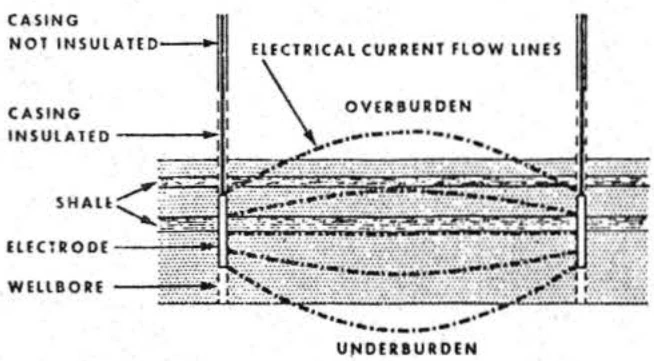

Figure 9. An application of electrical heating (from Newbold and Perkins 1977).

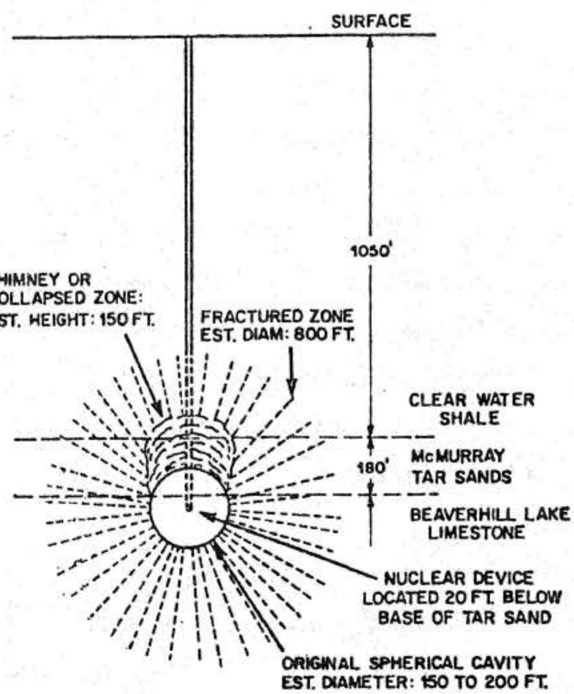

Figure 10. Schematic diagram of location and affected volumes in nuclear expansion (from Flock 1977).

Control of the slug and driving fluids is important for a high recovery efficiency as well as for economics, since the cost of fluid is expensive. As with other displacement type processes, some form of communication is required in the reservoir before commencing a flood. The absorption losses of the fluids to the reservoir rocks have presented problems to pilot plants in the United States. At present, there is no pilot testing of this process in the oil sands of Alberta. Figure 11 illustrates this process.

3.3.2.3 Bacteria. The use of bacteria is similar to that of diluents; that is, the bacteria is injected in slugs into the reservoir. Little is known about the bacterial effect on bitumen; research is endeavouring to develop a strain that is able to break down the heavy oil to lighter products.

Foreseeable problems associated with bacteria include the directional control in the reservoir, that is, the maintenance of the course of the bacteria from the injection well to production well. Also, the conversion to light products will have to be carefully monitored to avoid the complete breakdown of the bitumen to water and carbon dioxide.

3.3.3 Summary of Recovery Processes

In summary, most of the *in situ* techniques involve the injection of a fluid into the deposit to reduce the viscosity of the bitumen. The most readily available, least expensive, and easiest to handle of the fluids are air and water (in the form of steam).

All of the non-thermal techniques and the electrical and nuclear techniques, although of limited commercial value at present, have some potential for establishing communication between injection and production wells and for the enhancement of the steam injection and combustion recovery processes.

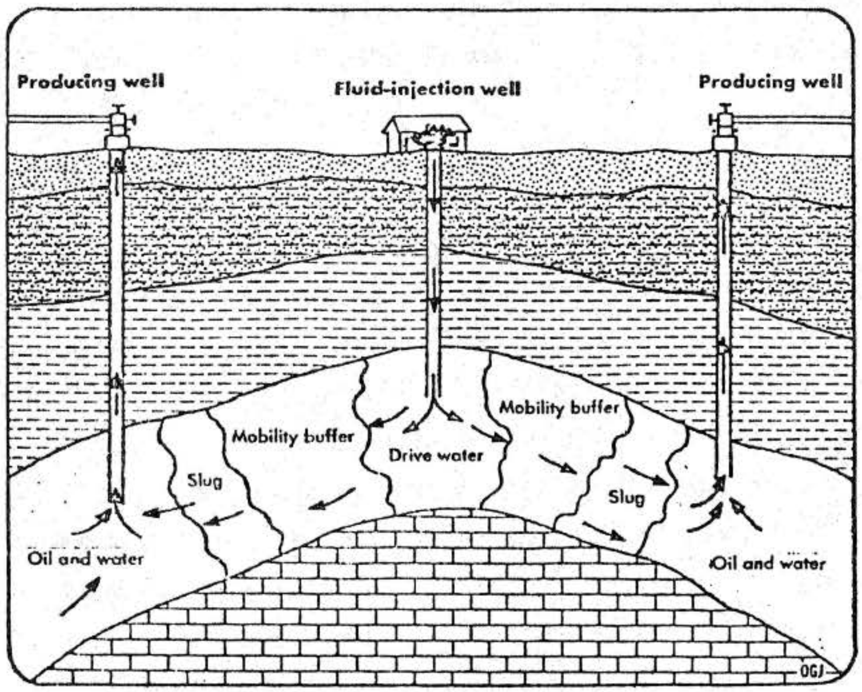

Figure 11. Micellar solution flooding scheme, a typical non-thermal *in situ* recovery process (from Carpenter 1972).

3.4 STAGES OF DEVELOPMENT OF AN *IN SITU* PROJECT

Because *in situ* projects involve new technology and, if carried out to completion, massive capital investment, there are a number of stages of development that each project developer will follow. These stages of development are: laboratory or bench test, field and pilot test, commercial test, and full scale commercial production.

3.4.1 Lab or Bench Test

A lab or bench test would develop the concept for a period of 1 to 3 years to the point where it could then be applied in the field. Research continues throughout the life of the project to develop refinements to the basic process.

3.4.2 Field and Pilot Test

This stage, in effect, scales up the critical parts of the bench test to actual field conditions. The first field phase of the pilot test is typically limited to one or two test wells to provide a basis for obtaining government regulatory reviews and approvals, and for understanding detailed engineering and feasibility on the proposed technology and location of a pilot plant. The main phase of a pilot test involves the construction of a small plant, which includes the drilling of wells and associated surface equipment. The testing, which may be from 4 to 6 years, is designed to determine various parameters and refinements to the lab tests.

3.4.3 Commercial Test

The next stage, requiring 1 to 3 years, is to expand the pilot test to a commercial test to confirm the findings of the pilot plant. At the completion of a successful commercial test, the operation is then expanded to meet economic scale requirements.

3.4.4 Commercial Production

Once the decision is made and governmental approval given, construction and start-up of a commercial-scale plant is estimated to require 5 to 7 years. The most likely scale of plant constructed would have a bitumen production capability of 140,000 to 160,000 barrels per day, resulting in a net synthetic crude production of about 125,000 to 140,000 barrels per day. Figure 12 illustrates the probable time scale.

3.5 PRESENT STATUS OF *IN SITU* RECOVERY PROJECTS IN ALBERTA

The activity in Alberta's oil sands has increased rapidly with the advent of the Alberta Oil Sand Technology and Research Authority (AOSTRA). A number of pilot plants are at various stages of development and several proposals for new commercial-scale projects have been reviewed by various regulatory agencies. Table 2 summarizes the major activities in the Alberta oil sands.

3.5.1 Peace River

The only operator in the Peace River deposit is AOSTRA/Shell. Shell began developing steam-based methods in the area in 1963, which has lead to the proposal of a cyclic steamflooding pilot. The pilot, now in the planning stage, will begin operations in 1979. It is planned to have seven steam injection wells and 24 production wells in a five spot pattern covering 65 acres, which include 15 acres for associated surface equipment.

3.5.2 Cold Lake

Cold Lake is the site of several operators investigating steam based recovery methods. Imperial Oil, with two operational pilots investigating the "Huff and Puff" process, has recently announced a proposal to construct a commercial operation to produce 145,000 b/d. The proposed site for the operation will occupy 63 square miles with an expected 10,000 wells to be drilled during the 25-year life of the project. Construction of the site is expected to begin by 1980 and be completed by 1985.

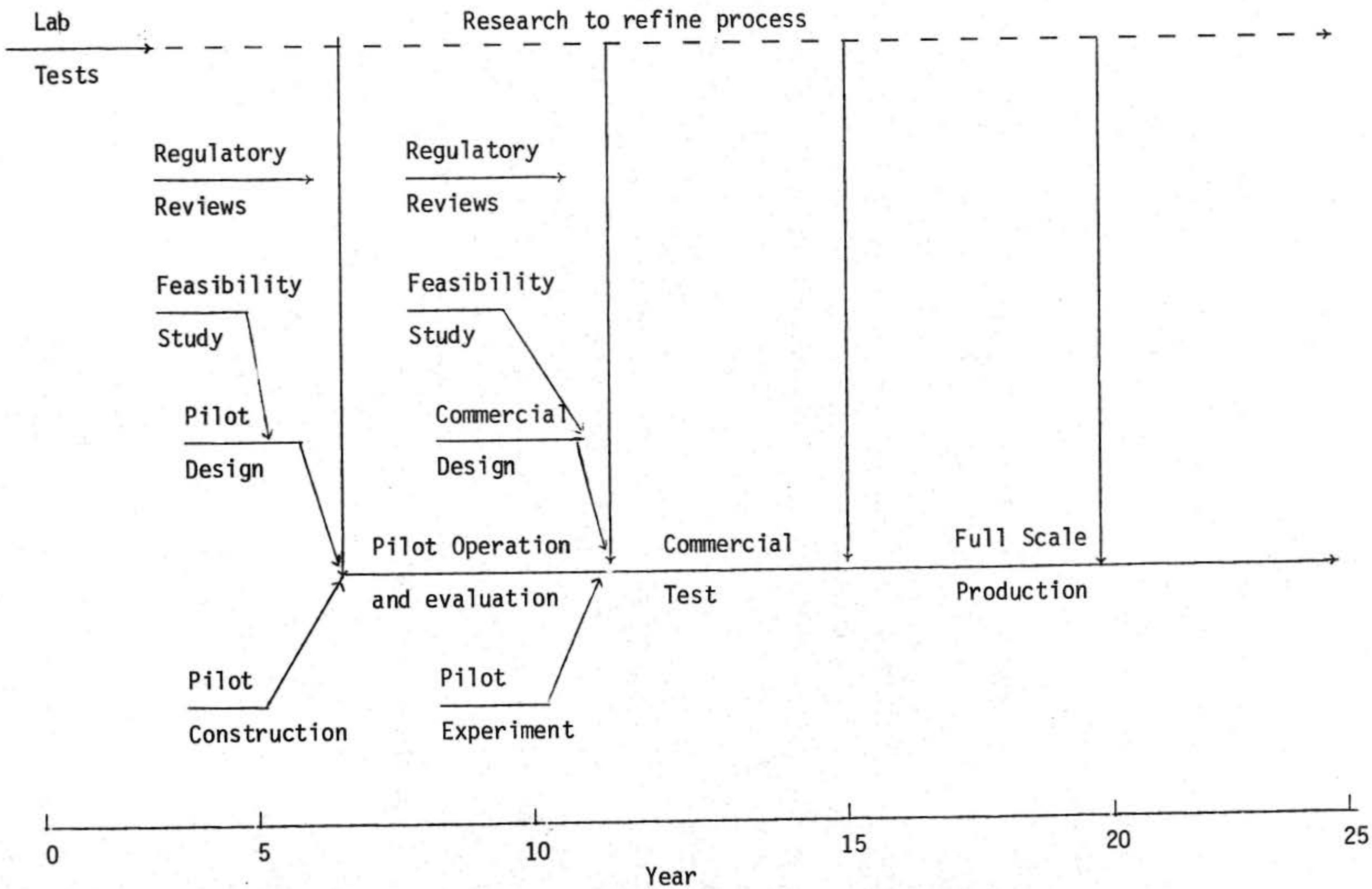

Figure 12. Probable development schedule of an *in situ* project.

Table 2. Active and proposed *in situ* projects.

Process	Status	Operator	Location
Athabasca			
COFCAW	Pilot construction completed, one year preheat period started November 1977	Amoco Canada Petroleum Ltd.	Gregorie Lake 27-85-8 W4
steam displacement	2 operational pilots	Texaco Exploration	McMurray 15-88-8 W4
Heating of shallow deposits	lab tests, 1977	AOSTRA/In-Situ Research and Engineering Ltd.	
Well communication by hydraulic fracturing	operation, 1977	AOSTRA/Numac	Surmont 30-83-6 W4
Electrical preheating/steam drive	begin pilot operation 1978	Petro-Canada Exploration Ltd.	Surmount
Wabasca/Grosmont			
steam stimulation in carbonate formations	begin 1977	Union Oil Co. of Canada	Buffalo Creek 5-88-19W
steam stimulation in carbonate formations	began pilot 1975	Union Oil Co. of Canada	Chipewyan River 21-89-22 W4
cyclic steam stimulation, steamflooding, solvents, combustion	began operations 1975	Gulf Oil Canada	Wood River 6-83-22 W4
Peace River			
cyclic steam drive	pilot operation by 1979	Shell Canada	Cadotte Lake 21-85-15 W5
Cold Lake			
Huff and Puff	operational pilot	Imperial Oil	May 27-64-3 W4
Huff and Puff	operational pilot	Imperial Oil	Leming 5-64-3 W4
Huff and Puff	begin commercial plant construction 1980	Imperial Oil	
steam stimulation/steam drive	operational pilot since 1974	Murphy Oil Ltd.	Lindbergh 13-58-5 W4
Huff and Puff	15 well operation pilot since 1975	Union Texas	Ardmore 20-62-3 W4
Huff and Puff	pilot construction completed 1976	Norcen Energy Resources Ltd.	Primrose Lake 6-66-1 W4
Huff and Puff	expanding 1977	Worldwide Energy Corp.	Fort Kent 28-61-4 W4
		Pacific Petroleums	Muriel Lake 29-59-4 W4
Huff and Puff	Pilot start up 1977	Gulf Oil Canada	Cold Lake 12-65-2 W4
steam stimulation/ combustion	16 well pilot start up 1978	BP Exploration	Marguerite Lake 7-66-5 W4
Huff and Puff	start fall 1977	Chevron Standard	Beaver Crossing 36-61-2 W4

Murphy Oil Ltd. has been operating a plant since 1974 near Lindbergh. A combination of steam drive and steam stimulation has been used to recover oil from a depth of 1,650 feet. The expansion from an inverted 7 spot on a 6 acre space to 7 spots has been approved.

Union Texas of Canada has maintained a production of 180 b/d of crude from a 15 well "Huff and Puff" operation since 1975. Five acre spacing has been used to recover the heavy crude from 1,250 feet.

The Norcen group (in partnership with Japan Oil Sands Company) has been using steam injection since 1976. A 9 spot of 7.16 acre spacing has been designed to produce 500 b/d from a depth of 1,410 feet.

Worldwide Energy Corporation (WECO) has two projects at Cold Lake. The first, a farm-out to Pacific Petroleums, is located at Muriel Lake. WECO at Fort Kent has, since 1974, been investigating cyclic steam stimulation. A peak production of 700 b/d were obtained from 6 wells on a 5 acre spacing. The target production capability of the facility is 6,000 b/d.

Gulf Oil has a pilot near Cold Lake, consisting of six wells on pads directionally drilled on 300 feet spacing. Operation of the pilot began in late 1977 and the first production using "Huff and Puff" was in February 1978. Expansion of the pilot is planned during 1978.

The combined efforts of AOSTRA/BP Exploration (including Hudson's Bay Oil and Gas, and Pan Canadian) will employ a combination of steam injection and combustion. Four 5 spot patterns have been drilled on a 5 acre spacing and plant start-up was planned for the spring of 1978.

Finally, at Beaver Crossing, Chevron Canada will be investigating cyclic steam stimulation at a reservoir depth of 1,120 feet.

3.5.3 Wabasca

Within the Wabasca deposit, Gulf Oil Limited has been operating since May 1975. A total of 34 wells have been drilled; tests of various recovery methods which have been undertaken include cyclic steam stimulation, steam solvent tests, streamflooding, and combustion processes. This operation is taking place in the Grand Rapids formation. Future test projects will concentrate on stream and fire flooding.

3.5.4 Athabasca

The Athabasca deposit, which has two mining operations in progress and a third mining plant in the proposal stage by Shell, is also the site of various experimental *in situ* recovery processes. The AOSTRA/Amoco project, which completed construction late 1977, will recover oil using the COFCAW process. Phase I, a pre-heat period of one year, will increase the permeability and flow capacity of the reservoir. The areal extent of the project is 22.5 acres with 16 producing, nine injection, and seven observation wells.

AOSTRA and the consulting firm In Situ Research and Engineering Ltd. have developed a heating process to be used at shallow depths. Lab tests were started in 1977 and field testing was planned to begin in 1978.

Texaco Exploration is continuing operation of two pilot plants at Fort McMurray using steam-based methods. The first pilot, which began in 1973, uses 10 acres with a 5 spot and 9 spot well pattern. The second pilot, on less than 4 acres, uses a 7 spot pattern. Total production to date is approximately 50,000 barrels of oil.

The joint venture of Petro-Canada, Canada-Cities Services, and Imperial Oil is planning to start in 1978 using a process which will first pre-heat the formation using electricity and will be followed by a steam drive.

Union Oil, with 3 wells at each of Buffalo Creek and Chipewyan River, is investigating the use of "Huff and Puff" to recover oil from the Grosmount carbonate formation.

3.6 MOST PROBABLE FIRST COMMERCIAL *IN SITU* APPLICATION

The thermal-based methods appear to be the most feasible extraction methods to date and, of these, steam injection or combustion methods should be the first operations to recover bitumen on a commercial scale.

The use of cyclic steam stimulation ("Huff and Puff") has been chosen by the authors as the first commercial *in situ* recovery technique for the purposes of this study. This decision is supported by: (1) the current stage of development and progress of the Imperial Oil pilots at Cold Lake, (2) the recent announcement by Imperial Oil of the construction of a full scale commercial undertaking, and (3) the worldwide use of steam stimulation for accelerating and increasing oil production from low-productivity reservoirs.

This choice does not preclude, however, the use of combustion or other techniques as being uneconomical or non-applicable, but is rather the authors' best judgement as to which technique will be first utilized on a commercial scale.

4. *IN SITU* STUDY REGION AND DEVELOPMENT MODEL

4.1 INTRODUCTION

The examination of environmental and social impacts of *in situ* development requires the delineation of some underlying assumptions. In part, the definition of assumptions is eased due to recently available information. Imperial Oil Limited has filed an application to construct a commercial *in situ* plant within the Cold Lake deposit. This application contains information on development and operational procedures respecting the "Huff and Puff" extraction method. Because this information is designed for a commercial development, this report has drawn upon the base data supplied in the submission.

To prepare a development scenario, the following assumptions have been made:

1. A geographic region is selected;
2. Timing and phasing of development is estimated;
3. A specific application of technology is chosen;
4. Plant size and daily input is established; and
5. A material balance is presented.

4.2 STUDY AREA

The geographic region chosen (see Figure 13) consists of 28 townships south of the confluence of the Athabasca and Clearwater rivers. The legal description of the area is:

Tp 84	Rg 6-10
Tp 85	Rg 6-10
Tp 86	Rg 6-10
Tp 87	Rg 6-10
Tp 88	Rg 6-10
Tp 89	Rg 6-10
Tp 90	Rg 6-10

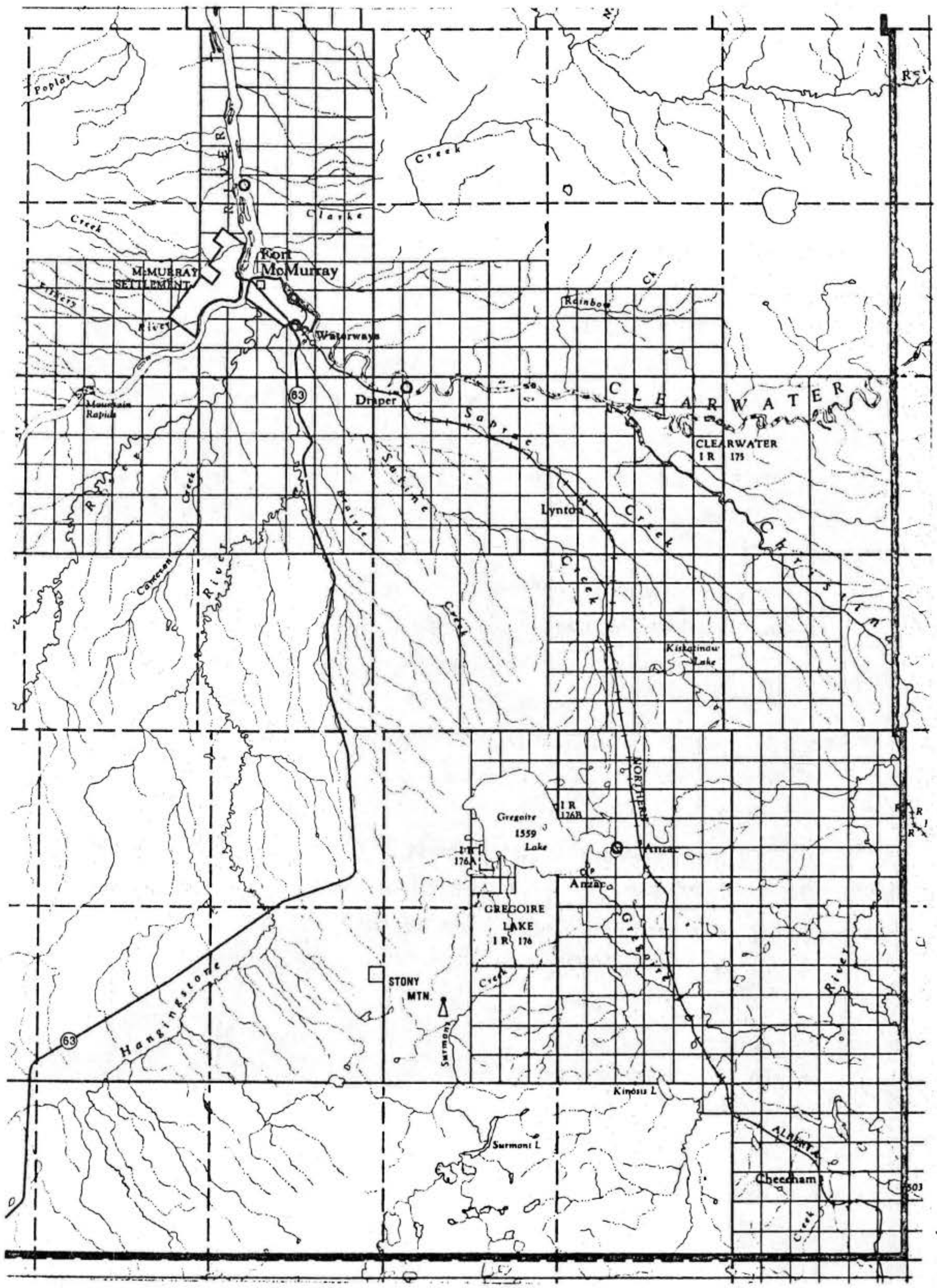

Figure 13. Study area for Athabasca development scenario.

The area selected for the first *in situ* plant is Section 1-12, Tp 85, Rg 8, and Tp 84, Rg 8, which includes Surmount Lake. This region has been selected because:

1. The area is of current interest as two pilot *in situ* plants are in operation east of AMOCO/AOSTRA;
2. The high water demand for a commercial plant necessitates the location of a plant in reasonable proximity to a water supply;
3. The depth of overburden precludes surface strip mining in this area;
4. The ore body in the region contains a relatively high bitumen content which would favor early exploration; and
5. The western side of the region could possibly permit deep well disposal-storage of liquid wastes.

4.3 DEVELOPMENT SCENARIO

4.3.1 Timing and Phasing

The proposed development scenario is based upon the most feasible method to date of initiating *in situ* oil production, i.e., "Huff and Puff". As outlined in Section 2.4, four stages are usually undertaken to reach full commercial production. In summary, these four stages and probable time frames are:

1. Laboratory or bench test, 1 to 3 years;
2. Field and pilot test, 4 to 6 years;
3. Commercial test, 1 to 3 years; and
4. Commercial production, 5 to 7 years.

The length of time from project initiation to full commercial production can take any where form 11 to 19 years, with an average of 15 years.

In development terms this means that, if the process were initiated in 1975, full production would not be reached until about 1990.

This schedule suggests most optimistically that construction of the first plant beginning in 1978 and full production by 1988 is achievable.

Should additional plants be constructed, the start and completion times using 1980 as year zero would be as indicated.

Plant No.	#1	#2	#3
Construction Start	Year 0	Year 4	Year 8
Construction Completion	Year 5	Year 9	Year 13
Full Production	Year 8	Year 12	Year 16

To allow for more efficient utilization of construction manpower, construction of the second plant is initiated as the first plant nears completion. Likewise, construction of the third plant is initiated as the second plant nears completion. At full production, each plant is assumed to have a capacity of 160,000 bbls of bitumen per day. As well, it is assumed that the bitumen available is sufficient for a plant life in excess of 25 years.

The development scenario is extended for over 20 years by assuming a base year of 1975 and projecting three *in situ* plants in operation. As will be discussed later, this report considers five *in situ* plants, the upper limit for the *In Situ* Study Region. Not withstanding, three *in situ* plants at full scale operation by the turn of the century seems optimistic in the authors' opinion.

4.3.2 Application of Technology

The previous chapter discusses the technology currently under investigation and the current state of the art for the recovery of the bitumen. Based on the known *in situ* extraction technology, it is assumed that the first plants would utilize the cycle steam stimulation or "Huff and Puff" method, with other plants utilizing the combination Forward Combustion and waterflood (COFCAW) method. In that regard, the Imperial Oil Limited application for a plant at Cold Lake is used extensively in the development model.

Thus, the assumption of transferability of Cold Lake technology is made with the knowledge that a thicker ore body and higher percentage concentration of bitumen by weight would suggest that the same areal extent of an *in situ* field in Athabasca would have a much longer life.

4.3.3 Operating Procedure

The proposed operating procedures dictate the surface land use and the amount of land under active use at any one time. The base site will contain upgrading facilities, and requires two square miles. In addition, four gathering stations would be strategically distributed on the lease site. Radiating out from each gathering station will be utility corridors. Off each corridor will be secondary corridors to the well pads. Figure 14 illustrates the layout facilities in the study area.

The utility corridors would be 165 feet in width and would contain a power line, road, utilities (containing steam pipes), and oil recovery lines.

The primary roads from plant site to the gathering stations would be in place during the life of the project. The utility corridors would be extended yearly as new well pads would replace depleted wells, reaching their maximum length at the end of the extraction process. At this time the radial utility corridors would extend throughout the lease area. The utilidors are designed to be four to six feet square and are placed on pilons one or two feet off the ground.

Each pad contains 20 wells and there would be nine such pads per section of land. The average economic life of each well is 6 years. Under full production of 160,000 bbl/day, 2,400 wells on 120 pads will be operating at any one time, giving a total of at least 10,000 wells during full production period. From the pad the wells are directionally drilled so that minumum land is disturbed. A typical well pad distribution and utility corridor is illustrated in Figure 15. In Figure 15, the dark line connecting well pads through the site represents the main utility corridor and the broken

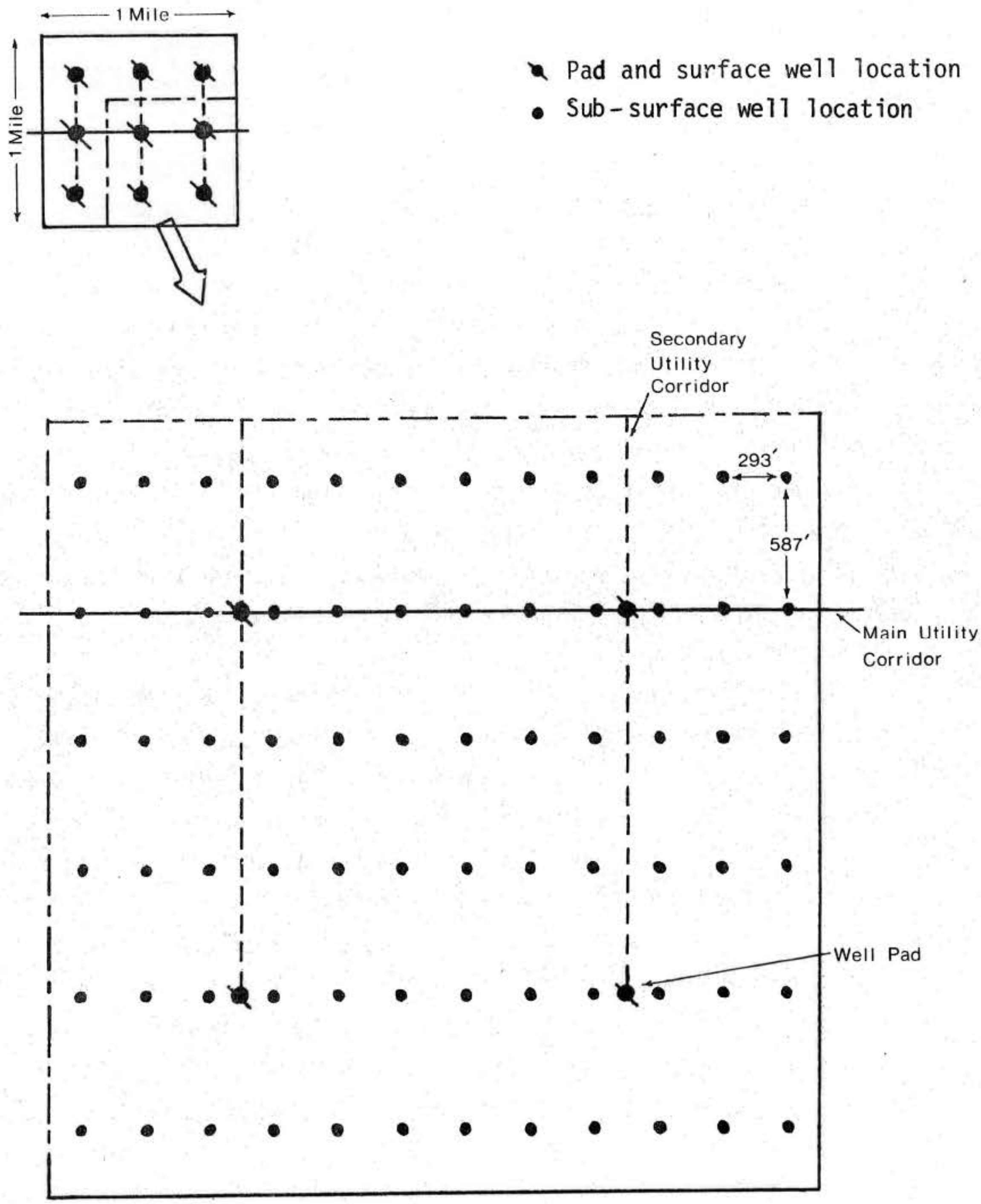

Figure 14. Typical well location on a 4 acre spacing and 2/1 offset.

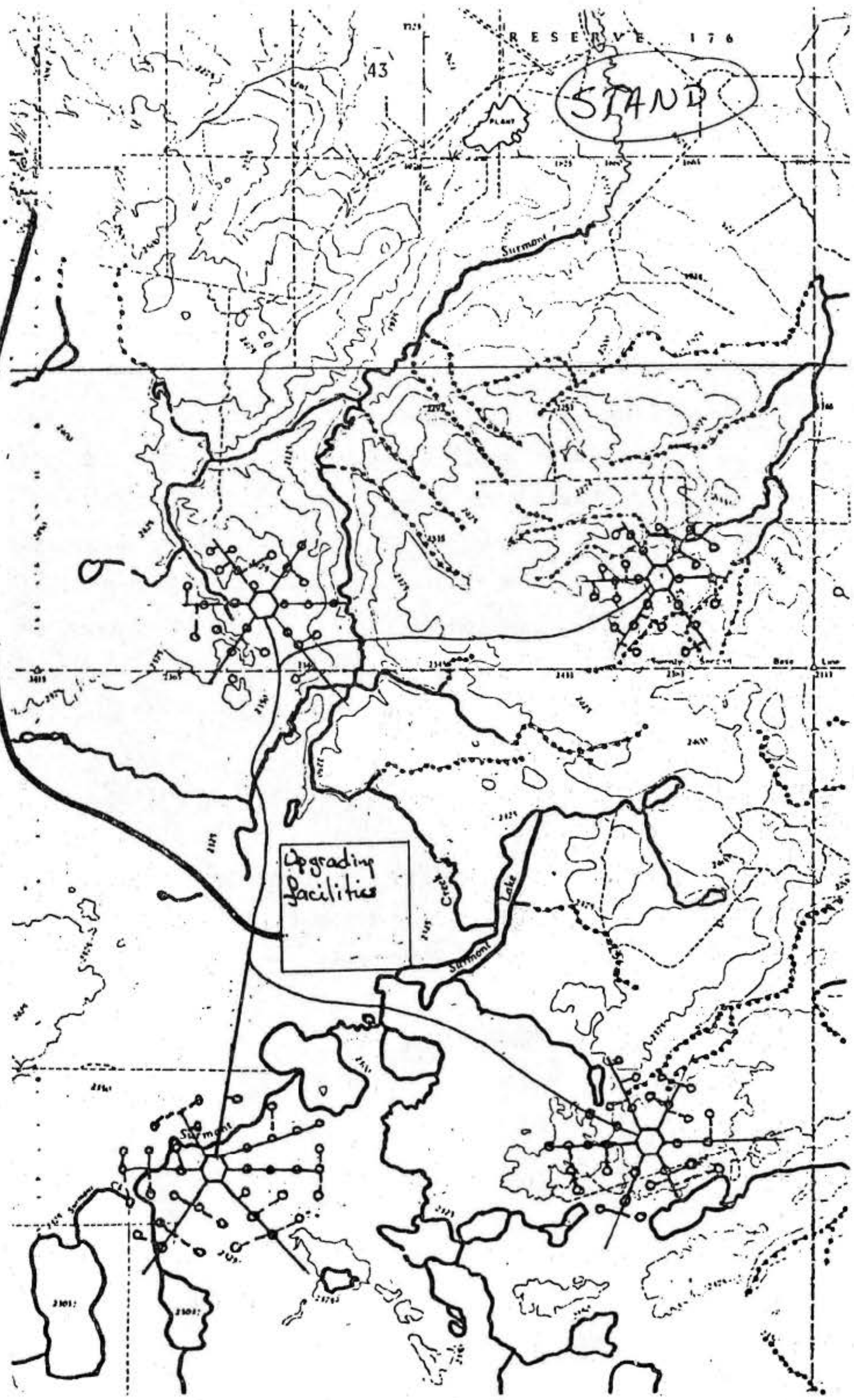

Figure 15. Surface land use Year 3.

line represents the secondary utility corridor.

As wells are depleted each year, well pads are removed and replaced at the outside perimeter. As well, life is assumed to be 6 years; a 6-year time span is illustrated.

An assumed recovery pattern is graphically illustrated in Figures 16 through 19, showing a possible utility corridor network and distribution of well pads. Figure 16 illustrates pattern in year 3, the first year of full production. Figures 17 to 19 outline the land use and well distribution patterns in years 9, 15, 21, and 27, respectively.

As well pads are shut down and removed, these 4 acre sites and access or "stub" roads would be reclaimed and replaced at the end of the secondary radial utility corridor.

On the basis of a scenario consisting of one production plant, the surface land disturbances and reclamation are illustrated in Table 3. Upon first reaching full production, the amount of total area disturbed amounts to 11.0% of total lease area. This percent of total net area disturbed increased slightly, reaching 14.4% in year 27.

It is noted that well pads which have completed production are removed and replaced at the extension of the radials from the gathering stations. Spent well pads and access corridors would then be reclaimed. The additional disturbances of total land area arises from the extension of the radial corridors.

4.3.4 Resource Input-Output Balance

Typically, in the process of resource extraction, the resource to be extracted is the limiting element. Other required inputs usually are readily available, or at least obtainable, without severe limitation. In the case of oil sands development the opposite is the case. The resource to be extracted is virtually unlimited in quantity whereas other process inputs are relatively limited or

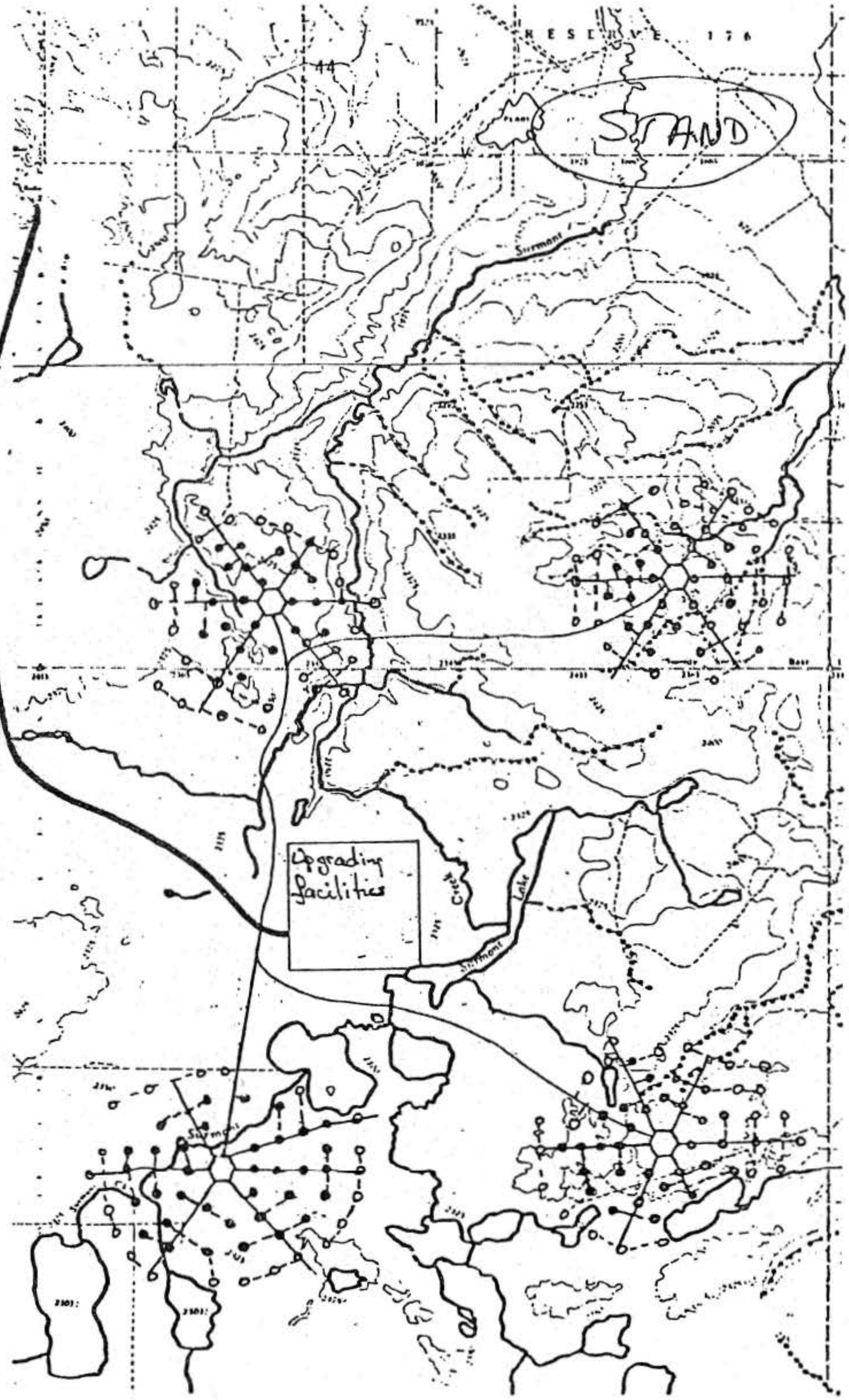

Figure 16. Surface land use year 9.

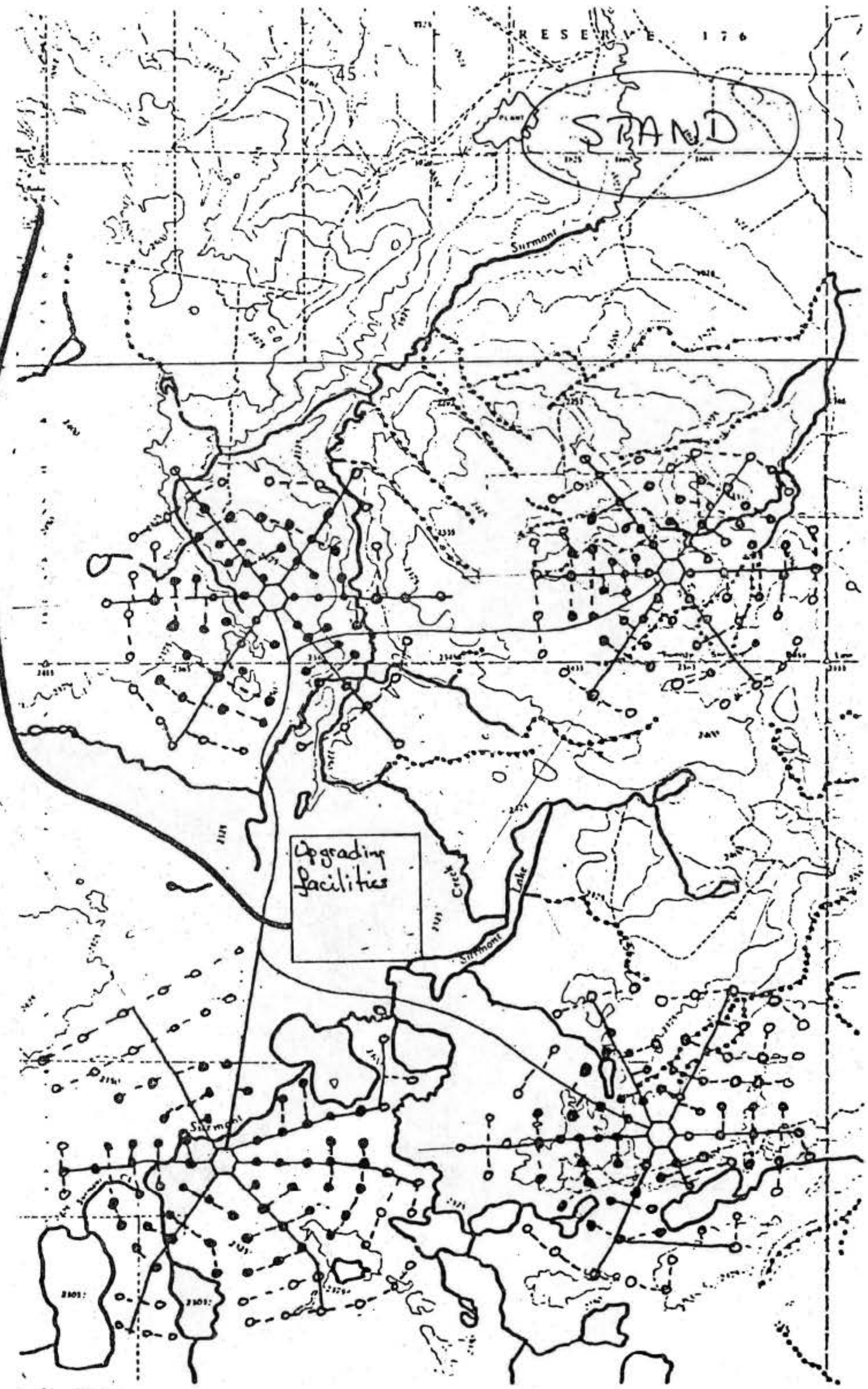

Figure 17. Surface land use year 15.

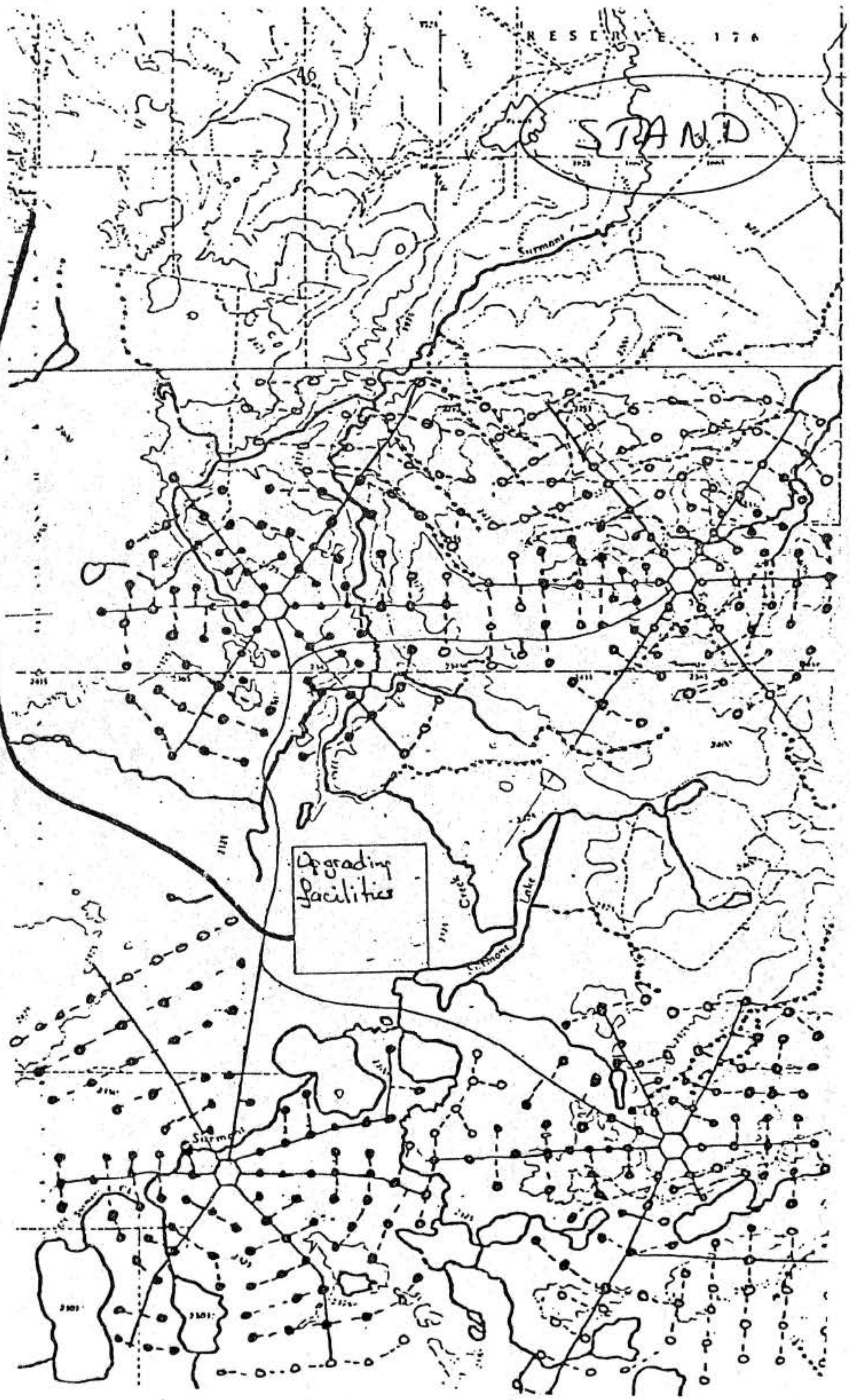

Figure 18. Surface land use year 21.

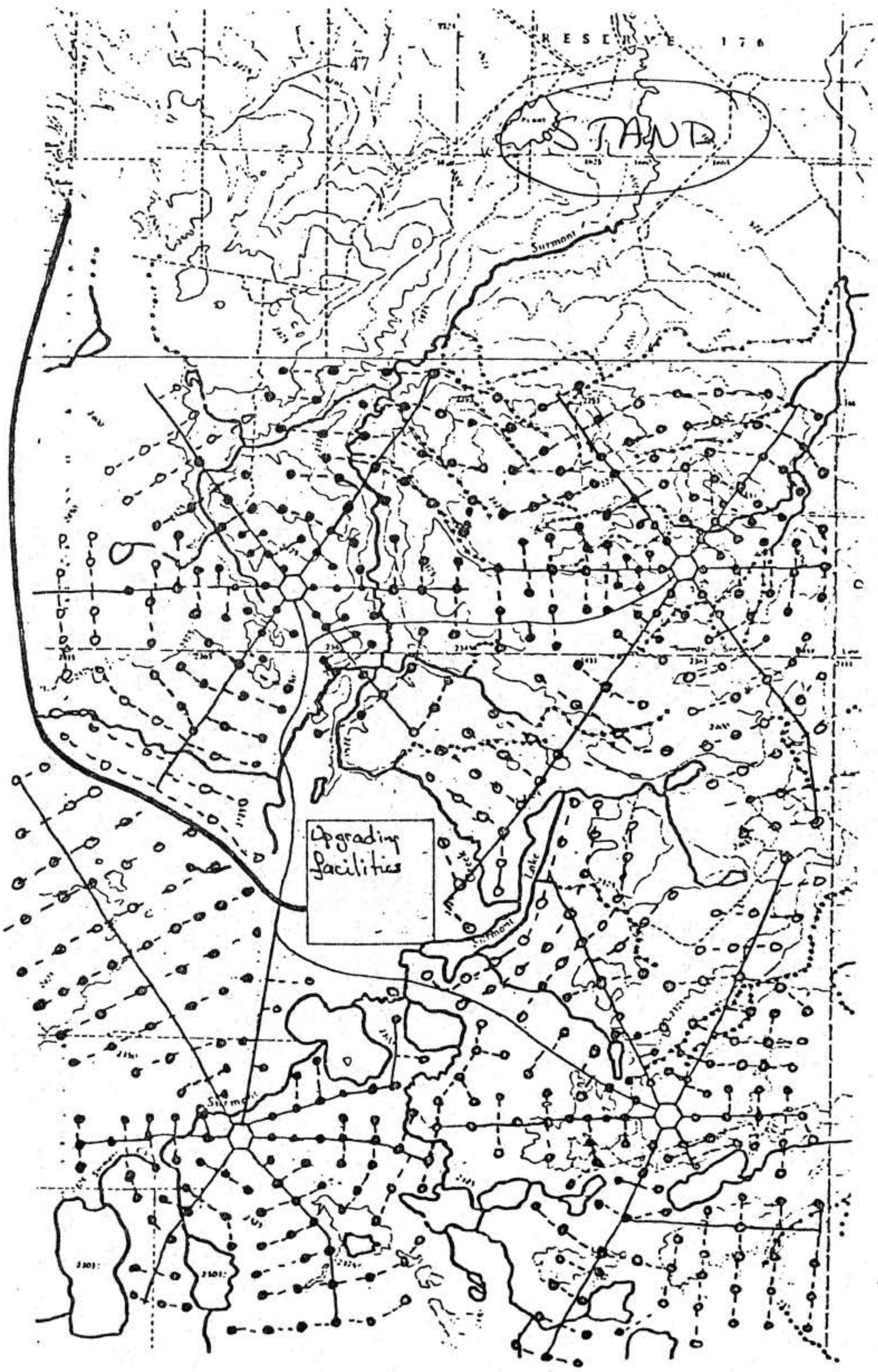

Figure 19. Surface land use year 27.

Table 3. Site land use and land disturbance (acres).

	Year					Total
	3	9	15	21	27	
Upgrading Plant - 1280						1280
Primary Roads 145						145
Bathering Stations 600			2230			660
Main Utility Corridors 205						205
Secondary Utility Corridors						
Stub Roads and Drilling Pads	1155	1144	1144	1144	1144	5731
Stub Roads and Pads Available for Reclamation		878	878	878	878	(3512)
Total Net Disturbed[a]	3385	3651	3917	4183	4449	
% of Lease Total	11.0	11.8	12.8	13.6	14.4	

[a]Of a total lease area of 48 square miles, 7,961 acres, on 25.9% of the land surface, are disturbed at some point in the development.

relatively costly. Hence, development can provide only as rapidly as inputs are available. For example, a "Huff and Puff" plant requires a total of 901,000 bbls of water daily, of which 319,000 bbls can be recycled and the balance has to be discharged and made up from some water source. This amounts to approximately 50 cubic feet per second. The water balance for Imperial Oil's Cold Lake plant is illustrated in detail in Table 4.

Each type of process applied in this scenario has a different resource input requirement and a different mix of discharges. The key inputs and outputs are summarized in Table 5 for the "Huff and Puff" and COFCAW processes. Inputs and discharges vary with the type of heat source utlilized. Coal is assumed as the heat source in Tables 4 and 5.

4.4 INFRASTRUCTIVE REQUIREMENTS

The scaling up of our hypothetical *in situ* project has assumed a site-specific location on or near Surmont Lake. This lease, using the present highway network, is approximately 32 miles from Fort McMurray and 11 miles from Anzac.

Given the proposed Surmont location, an estimated employment multiplier of 1.6 is used. This means that, for every primary job, 0.6 jobs are created in the service sector. Using the figure of 2,000 permanent employees, an additional 1,200 jobs are created in secondary and tertiary employment, for a total employment of 3,200. To arrive at the total population an aggregate figure of 2.5 has been used and must be multiplied by the employment figure of 3,200 to arrive at an estimated permanent population level of 8,000.

The primary human system impact issue which must be addressed is where the 8,000 people directly and indirectly associated with the project will be domiciled. Several alternatives are available:

Table 4. Water balance for the Imperial Oil plant at Cold Lake, using coal as a heat source.

	MB/D
WATER REQUIREMENTS	
Injection Steam	400
Process Water and Steam	124
Cooling Tower	162
Water Treatment Backwash	111
Utility Water	80
Potable Water	24
	901
WATER CONSUMPTION	
Consumed in Operations	
Displacing Bitumen	160
Cooling Tower Evaporation	126
Hydrogen Synthesis	15
Coke Gasification	32
	333
Waste Disposal	
Deep Wells -	
Water Treatment Backwash	48
Sour Water	15
Desalter Brine	15
Chemical Wastes	5
	83
Surface -	
Water Treatment Backwash	63
Cooling Tower Blowdown	21
Boiler Blowdown	17
Utility Water Waste	67
	168
RECYCLED	
Produced Water	240
Sour Water	28
Sanitary Wastes	24
Oily Wastes	25
	317
	901
WATER SUPPLY	
Recycled Water	317
Fresh Water Make-up	584
	901

Table 5. Input-output balance per plant per day.

	Process	
	"Huff and Puff"	COFCAW
Bitumen Production	160,000 bbls	160,000 bbls
Water Balance		
Total Required	901,000	800,000
Recycle	317,000	640,000
Make-up	584,000	
Air Emissions		
S	43.0 <tons	
SO_2/SO_3	0.4 <tons	9.7 <tons
H_2O (vapour)	126.0 M bbls	2100.0 <tons
NO_x	7.2 <tons	14.0 <tons
CO	5.6 <tons	0.82 <tons
Particulates	.3 <tons	3.89 <tons
Elemental Sulphur	1124 <tons	
Natural Gas Required	55 MMCF	
Coal Required	17.6×10^3 <tons	
Purchased Electricity	250 megawatts	

1. Option 1--Workforce commuting from Fort McMurray using existing modes of transport (i.e., car, bus);
2. Option 2--Workforce commuting from Anzac which would be expanded substantially to accommodate growth;
3. Option 3--Workforce commuting from Fort McMurray using high speed modes of transportation (i.e., rail, air); and
4. Option 4--Workforce commuting from a new urban centre situated on or near the work place.

Of the above four options, all have received or are currently receiving study by the Northeast Regional Commission in relation to the proposed Shell mining scheme to be situated near McClelland Lake, north of Fort McMurray. Several studies addressing these options have been undertaken, from which the following conclusions seem to emerge.

1. The outer boundary of the "practical" commuter shed for travelling to work is approximately 30 miles.
2. Employee compensation for travel time is typically necessary when travel time exceeds 0.5 h per one-way trip.
3. Employee compensation for travel over the useful life of an *in situ* project approaches in magnitude the capital costs of building a new urban centre.
4. Use of a high speed rail for travelling to work will not materially affect or reduce travel time either on a one-way or round trip basis. In addition, a high capital investment will be necessary to upgrade the existing rail bed.
5. Residents of Anzac have expressed their view that they do not want to accommodate the impact of a full scale *in situ* project.

6. Journey to work by use of air travel for a large workforce is still untried in Alberta. However, one resource developer is utilizing the technique for a permanent workforce of approximately 200 employees.

Based upon the above considerations, and in the face of existing technology and public opinion, Option 4--a new urban centre--is selected to accommodate the projected direct and indirect employment and population impact of a commercial project.

4.4.1 Manpower

4.4.1.1 General. With the present "state of the art" knowledge of *in situ* technology it is generally felt that a commercial process will require a smaller operating workforce than a conventional mining plant of equivalent production capacity. This is mainly due to elimination of several major steps associated with mining, such as the drainage and removal of muskeg, removal of overburden, and the overall strip mining technique. Associated with these direct mining activities are the support services, such as vehicle maintenance, which would be largely absent from *in situ* projects.

4.4.1.2 Pilot plant. Manpower requirements of the pilot plant with estimated production capacity of 3,500 bbl/day will require, during peak construction activity, up to 250 workers. At this level of activity, all personnel can be easily accommodated in temporary camp quarters. To operate this facility, a staff of 35 personnel are required. In addition, a staff complement of up to 25 people are needed to monitor the project.

At the operating level of activity for the pilot project, the number of personnel employed would be too small to provide anything more than "camp"-type accommodation. This camp would probably be augmented by a "fly in-fly out" shift exchange either to the major point of settlement, Fort McMurray, or Edmonton.

The impact problems in the human system will start to accelerate if the developer's phasing of a pilot plant jumps in multiples to full scale commercial production. In other words the "additive" effect will pose many urban alternative pressures to provide more than temporary camp type accommodation to permanent operating personnel.

4.4.1.3 Construction. The movement from a pilot project to a commercial project is a massive construction undertaking estimated to require a considerable work force over a 5 to 6 year period. The skill mix required will be somewhat different than a mining project, with less emphasis on heavy equipment operators and labourers and more requirements for boilermakers, pipefitters, and insulators.

Total construction manpower is expected to build up through the summer and winter months at the maximum in year 5, as follows:

1. Year 1--170;
2. Year 2--1,170;
3. Year 3--4,000;
4. Year 4--8,600;
5. Year 5--9,200; and
6. Year 6--1,800.

At the regional level this construction impact will be varied and substantial.

A large and sophisticated construction camp will need to be built. Using the Syncrude model, this camp will require:

1. Portable water system, 0.62 MGD (million gallons per day);
2. Sanitary sewage system, 1.24 MGD (million gallons per day);
3. Solid waste disposal system; and
4. Fire protection services and recreational facilities.

Tied into the construction camp will be the requirement for a job site transportation system, probably in the form of bus service. In addition, an airstrip will be necessary for direct site access.

4.4.1.4 Operating. Estimates of the operating workforce requirements for a 160,000 bbl/day *in situ* extraction plant, based on our current knowledge of commercial technology, varies substantially. The Imperial Oil project at Cold Lake has estimated its operating work force at 2,000, whereas earlier estimates undertaken by Alberta Advanced Education and Manpower indicate 1,300 full time employees. Proponents of other projects of a similar nature place the operating workforce figure between 1,400 and 1,800. Experience with similar projects of the nature of Syncrude has indicated wide upward swings in operating manpower as technology and engineering design considerations are finalized; thus, the figure of 2,000 permanent operating personnel has been selected.

Preliminary estimates indicate operating manpower will be hired in stages during the latter part of the construction phase as well as following the commencement of production.

4.5 LONG-TERM DEVELOPMENT SCENARIO

As noted, in conventional extraction of finite resources, the actual resource is normally the limiting factor; other factors of production are available within economic limits. The oil sands resource, for all intent, is limitless with other factors of production limiting the ability to develop the resource, recognizing current technological and economic limitations. The availability of water appears to be the limiting physical resource that will dictate the number of extraction plants. Current knowledge suggests that no more than 10% of the minimum flow should be extracted for a water course. The Athabasca River system is the only reliable water supply available and, hence, the water demand on this river dictates long-term development potential. The minimum monthly recorded average flow of the Athabasca is 3,700 c.f.s. Thus, the 10% rule would provide 370 c.f.s. of water for industrial use.

Currently, two oil sands plants, GCOS and Syncrude, are in operation and a third plant, Shell Canada Ltd., is proposed. The total projected output of these three surface mines will require

110 c.f.s. of water from the Athabasca River. This water demand is inclusive of plant, municipal, and other uses. Thus, a balance of 260 c.f.s. is available for further uses. An *in situ* plant with daily production of 160,000 BPCD has an estimated requirement of 50 c.f.s. of water. Thus, there would be sufficient water supply to operate five *in situ* plants of 160,000 BPCD output in addition to the three open pit mining operations.

These calculations are based on current technology of water use, clean-up, and recycling. However, a major technological break-through reducing water demand could substantially alter the number of plants which could be supported by the river system.

In addition, the 10% of minimum flow rule, although accepted by this report, is and certainly has been questioned as perhaps being too conservative. On- or off-river storage could also remove or alter water availability, consumption, and disposal as the limiting factor.

4.6 SUMMARY

To assess possible environmental impacts, an operational scenario of a commercial *in situ* plant has been developed, assuming application of the "Huff and Puff" extraction method. A region 30 miles south of Fort McMurray was selected as the geographic setting. The operational plan outlined was based largely on the production plan outlined in the Imperial Oil Ltd.'s Cold Lake application. The physical resource inputs and emissions anticipated in this application were used as representative of this application of technology.

Surface land disturbances and the distribution of utility corridors and well pads are based on this production scenario.

Finally, a review of long-term potential of *in situ* extraction development is undertaken. Based on the application of current technology it is concluded that five *in situ* plants are feasible in the AOSERP study area.

5. IMPACT MATRIX ANALYSIS

5.1 INTRODUCTION

The use of a detailed impact matrix provides an effective checklist that systematically analyses the probable impact of development activities on the environment. Impact matrix analysis was used in the Imperial Oil Cold Lake application and as an analytical tool during the project team work sessions of this report. However, because of the speculative nature of this report, the summation of the matrix analysis results most meaningfully in a broad overview as presented in Table 6.

Table 6 emphasizes that development impacts can place stress upon the environment in both cumulative and synergistic fashion. The essence of environmental protection is to recognize these symptoms of stress and avoid the threshold limit at which unacceptable environmental degradation will occur.

Plants of similar technology will generally cause cumulative impacts upon the environment, whereas oil sands plants of differing technologies also introduce the possibility of synergistic impacts. In this overview analysis the bias has, therefore, been to highlight broad environmental issues and their implications with a particular focus on the regional aspects of *in situ* oil development.

The range and magnitude of impacts derived from the development of several plants of differing technologies is far greater than experimental considerations pertaining to a single pilot plant. It may be that the most significant impacts will result from low stress and cumulative factors operating over a long period.

Consideration is given, therefore, to impacts identifiable from a single plant which will be replicated for multi plants. Data are insufficient to carefully weigh or rate impacts on a one plant, two plant, or five plant progression. That type of analysis must await site specific details and acquisition of suitable baseline data.

Table 6. Impact matrix.

Development Scenario/ Environmental System	One Plant, "Huff and Puff" Technology, located more than 30 miles from existing urban centre	More than one plant, all "Huff and Puff", located in close proximity to each other--15 miles or less separation	Combinations of "Huff and Puff" and COFCAW technology located in close proximity
Land	- 13 to 16% total lease area physically disturbed - total lease area lost to most other uses, i.e., hunting, recreation, ungulate production for life of project	- cumulative effects → threshold limits	- cumulative and synergistic impacts → threshold limits
Water	- local watersheds altered - 50 c.f.s. water demand--pipeline from Athabasca - major recycle-disposal problems	- cumulative effects → threshold limits	- economics of scale in water delivery
Air	- localized effects dependent largely on topography	- cumulative effects → threshold limits	- synergistic and cumulative effects
Human	- new urban centre required - increased recreational access demands, land use conflicts potential very high - company town element	- some economics of scale possible for infrastructure - company town effects reduced	- no difference unless air quality changes--minor effects

5.2 WATER SYSTEM

The *in situ* processes currently proposed for commercial application require tremendous quantities of water, estimated at 901,000 bbls daily. Of this total, 584,000 bbls consists of freshwater make-up and the balance is recycled.

Such large quantities of water are not available from underground sources, necessitating the aquisition of water from surface sources. The primary water source would be the Athabasca River. A water pipeline from the river to each plant site would be required.

5.2.1 Water Use, Disposal, and Drainage

The immense water requirement and its associated problems is the most significant environmental consideration of a "Huff and Puff" *in situ* development. Water withdrawls, even for one plant, represents a significant and constant demand with attendant drawdown or flow reductions. It is estimated that the volumes required would preclude establishment of more than five *in situ* plants utilizing 10% of the Athabasca River at minimum flow. Additional development would either significantly deplete the Athabasca River or require storage or inter-basin water transfers. The environmental implications are numerous and would extend beyond the region, downstream throughout the river basin. Implications are greatest for aquatic species, primarily fish, and their habitats. Withdrawls can affect littoral zones, spawning areas, river morphology, and benthic organisms.

Disposal of wastewater by injection may introduce contamination of potable groundwater supplies or precipitate saline discharge from existing aquifers into rivers and streams. Any significant increase in sodium chloride in existing streams would have significant effects on aquatic biota.

Oily disposal water presents pollution problems (spills) from accidents in storage, processing, and disposal.

Master drainage plans are assumed in any plant operation as part of construction practice as a mitigation against surface and sub-surface contamination. Such plans will result in lesser flow in some areas and increased flow in others. In general, surface drainage plans will decrease flows in watercourses and increase rates of runoff. The implications are effects on ecological stability of aquatic environments (flows) and drying of large areas of muskeg soils with attendent changes in vegetation.

The combination of volumes of water used, effects on surface and sub-surface hydrology, and contamination potentials present a wide range of potential impacts on both the terrestrial and aquatic environments. The most significant mitigation potential lies in the development of a technology to allow recycling of water and reduce water demands.

The development of communities and their associated demands and infrastructure will introduce other impacts related to water: domestic use, recreational use, pollution, and siltation.

Each environmental component, from fish populations to ecological stability of surface waters, requires intensive consideration on a site and regional basis and, where appropriate, on a river basin level.

In summary, surface water resources may be affected in four ways:

1. Changes in the area's surface runoff characteristics due mainly to changes in vegetation cover, drainage, or road ditches, drainage of low lying areas, and changes in surface topography;
2. The use of water in the bitumen production and upgrading process;
3. The release of used waters to surface water supplies; and
4. The movement of underground formation waters to the surface.

As indicated, groundwater resources have not been identified, to date, as a major water supply for industrial operations in the area; however, they are regularly used for residential uses, and in some cases for urban municipal supplies. Changes in surface water resources may decrease the recharge of the water-bearing formations and, thus, reduce the amount of useable groundwater.

An alternative disposal method for the unuseable waters can be the "deep well" method, where suitable underground formations are available. The potential for this method in the Fort McMurray area has received some attention. Recent studies indicate that the easterly area should be ruled out for this use; however, the westerly area was evaluated as "possible". One of the critical parameters here is the containment ability of the receiving formation; in the Surmount Lake area, this factor is sensitive because the underlying evaporite saline formations are suspected of being the source of chloride seepages to the surface.

5.2.2 Summary of Total Water Demand

The technology applied to the extraction of oil from the oil sands for both the surface mining method and *in situ* method, as noted, require huge quantities of water. Two principal areas of concern surface: the acquisition of adequate supplies and the disposition of used water.

Available data indicate that sub-surface water supplies are insufficient for the operation of plants of the proposed sizes. As well, although numerous streams meander throughout the Athabasca oil sands area, the flows are intermittent and not sufficient to operate a plant. Thus, the only practical water supply available for the operation of oil sand plants is the Athabasca River. Previous conclusions suggest that water withdrawl from the river system should not exceed 10% of minimum flow. On this basis, 370 c.f.s. are available for withdrawl. Two plants, GCOS and Syncrude, currently withdraw water for plant operation. Shell Canada is proposing a mining operation, similar in size to the Syncrude plant, north of Fort McMurray. Total water withdrawl for these three plants is estimated at 110 c.f.s. With a 50 c.f.s. requirement for each *in situ* plant, the addition of five *in situ* plants would be the maximum that could be sustained on the basis of water demand, exclusive of other large users.

The disposition of used water also creates difficulties. Because much of the post-process water contains oil and other contaminants, surface disposal through existing watercourses may not be possible.

Thus, a critical area of consideration for the development of the resource is the regional water balance. Policies influencing the rate of development of the resource will influence the degree to which the water balance situation becomes critical. Several options emerge which deserve consideration in finding solutions:

1. Flow augmentation projects could be developed along the Athabasca River;
2. Further research aimed at reducing process water demand could be undertaken; and
3. New methods of cleaning used water could be investigated to increase the volume of water recycled.

5.3 AIR SYSTEM

The air pollution potential of these projects could be classified as major and, therefore, complete and thorough consideration must be given to air pollution control at both the design and operation levels. The upgrading of 160,000 bbls/day of raw bitumen to marketable crude requires a large and complex oil refining plant. Also, the combustion of fuels to provide the required heat and pressure to extract the bitumen from the formations is large, as indicated in the Cold Lake proposal. The coal fuel required is estimated at 6,240 LT/D or 2.3 million tons/year and the purchased electricity amounts to approximately 288 MW.

The air pollutants from the upgrading section of *in situ* projects are expected to be similar to those resulting from the mining method. However, the pollutants from different *in situ* techniques of producing the raw bitumen no doubt will differ appreciably. In particular, *in situ* combustion of in-place bitumen is expected to require special study. The combustion of fuels in a properly designed furnace, with good control of temperature and the air: fuel ratios produces a minimum amount of carbon monoxide and oxides of nitrogen.

Underground combustion is not subject to the same degree of control of temperature, air:fuel ratio, or combustion area. The hot areas tend to produce more oxides of nitrogen. The cooler areas, where the oxygen is nearing depletion, produce more carbon monoxide. The nitrogen content of the gases produced with the bitumen could be troublesome as an inert material requiring disposal.

The significant meteorological parameters used in the air pollution control program planning for *in situ* plants may require development for new areas. However, the information and experience gained during AOSERP work related to Syncrude and GCOS will assist in determining the extent of additional meteorological information required for the Surmount Lake or other new areas.

Any proposed air environment management program will have to consider the overlapping of the effects of emission "footprints" of adjacent plants in the same area as well as the combinative or additive effects of one area on other areas. One of the main factors here will be the horizontal and vertical separations between project sites. This, in turn, will depend to some extent on the quality of the oil sand deposits in the area and the recovery efficiency of the *in situ* method to be used.

5.3.1 Emissions and Toxic Materials

Large quantities of toxic gases from plant sites will have significant impact on air quality. Oxides of nitrogen (NO_x) and sulphur (SO_x), and carbon monoxide (CO) are of particular concern. Mitigative techniques such as scrubbing and stack heights are standard operational procedures. However, because of residual emissions and their ultimate descent, ground level concentrations may introduce effects on vegetation (e.g., effects of SO_2), or a synergistic effect (particulates in combination with SO_2). In addition, ground level concentrations of CO would have to be maintained within acceptable levels to avoid danger to humans and wildlife.

Because of the long term of continuous operations, present design standards for individual plants may not be adequate to deal with regional air pollution from several plants. This is particularly true where overlapping dispersion and cumulative downwind concentrations may exceed ground level concentration standards. It is important, therefore, that regional criteria for air quality be developed and integrated into design standards for each plant.

5.3.2 Particulates

Fly ash from coal incineration is created in large quantities, necessitating disposal and/or storage with attendent possibilities of contaminated groundwater by leaching. Also, transportation of coal will result in particulate loss and an undetermined potential for sulphur contamination.

The possible combination of sulphur compounds with particulate stack emissions may pose environmental hazards and should be assessed.

5.4 LAND SYSTEM

5.4.1 Soils and Vegetation (Terrain Disturbance)

In the base case, terrain alteration as a result of construction of drilling pads, roads, pipelines, upgrading plant, gravel removal, drainage control, stockpile sites, etc. will be extensive. It is calculated that 86 acres out of every square mile of new field will be disturbed and occupied by facilities in addition to the two square miles for the upgrading plant. Intensive alteration will, therefore, comprise over 15% of the total land surface of a plant over a long period of time (25 years operation, up to 15 years development period). The types of alterations envisaged represent a permanent impact, at least over the life of the project and perhaps longer, depending on abandonment procedures. Approximately 4,650 acres on each lease will be affected and taken out of their existing state. This is equivalent to approximately 325 miles of a large diameter pipeline right-of-way. Five or more plants would then have terrain implications equivalent to the largest industrial projects in Canada.

A variety of plant associations would be altered within the boreal mixedwood forest zone. Large areas of muskeg present particular problems in revegetation and drainage. Soil textures and fertility vary, and erosion susceptibility is a function of terrain sensitivity. A terrain sensitivity classification is required to anticipate erosion control and revegetation requirements. A master revegetation program is prerequisite to mitigating adverse effects of terrain disturbance.

Disturbed and altered vegetation constitutes direct habitat loss. In the long-term, interference with surface drainage patterns is likely to affect areas of vegetation not directly altered by road and pad construction. Depending upon surface water alteration, trends could be established which favour differing successional stages or a different edaphic climax than would occur normally in the area.

5.4.2 Linear Disturbance and Access

Linear disturbance refers to a number of environmental stresses, particularly those affecting terrestrial wildlife and fisheries. It involves sensory disturbance to birds and mammals, particularly ungulates (moose, deer, and caribou), resulting from noise, vehicular traffic, physical presence of roads, human presence, and actual or perceived barriers (snow ploughed berms, utiladors, and pipeline gathering systems). Because of the systematic network of roads, gathering systems, and drill sites represented by the base case, and the continuous activities, linear disturbance has far greater implications than simply habitat removal. The progressive nature of the development is likely to result in extensive and reinforced displacement of birds and mammals from affected habitats, which may be sufficient to alter utilization of large areas of physically undisturbed habitat. If utiladors are employed in conjunction with the road network, the combination of a physical barrier and sensory disturbance would have severe implications for ungulate populations. This would be exacerbated with each successive plant and would likely alter patterns of movement and distribution of wildlife within the region.

Woodland caribou would be particularly affected in a multi-plant scenario because of their seasonal movements.

Transmission lines and towers would be a source of mortality to migrating birds and siting of facilities may interfere with raptorial birds.

Culverts associated with roads and drainage programs can create velocity barriers to fish passage and road construction is a major source of siltation in streams. Although road traffic is a direct source of mortality to some wildlife species, effects can be mitigated to some degree by traffic control.

5.4.2.1 Access. Road networks will create environmental stresses by providing access to habitats and populations previously inaccessible. Increases in hunting, fishing, and recreational pressure are all impact factors which may place excessive stress on wildlife and fish populations if uncontrolled or unregulated. Passive recreational activities may affect sensitive areas by increasing human disturbance (e.g., to nesting areas), or by increasing pollution. The influx of large numbers of people will create recreational demands and access problems which will require resolution, particularly with the establishment of new towns and many plants. Linear disturbance problems will be compounded in the region with increased traffic or transportation corridors and the use of private vehicles.

5.4.3 Site Specific Disturbance

Drilling rigs and pads will be foci of disturbances to wildlife from noise generated by men and machines. Aircraft disturbance, particularly helicopters, can disturb nesting birds and ungulates on winter ranges.

If a rail network is involved in the transport of coal to several plants, unit trains will add to mortality of wildlife and contribute to barrier effects. In summary, each plant presents a growing disturbance matrix with each successive annual drilling program.

5.4.4 Urban and Secondary Development

In previous sections mention has been made of implications of urban development on resources and the environment. Impacts of *in situ* development on the urban development are expected in such matters as potable water supplies and air pollution. New town planning is required to deal with such problems. The development of an urban infrastructure itself is characterized by well-known impact factors such as sewage treatment, solid waste disposal, pollution, and habitat alteration. Development of secondary industries associated with towns and the opportunities provided by the *in situ* development itself will introduce a range of impact considerations in the long-term. In the sense of proximity to the urban center, these will contribute to regional environmental impacts although each stage of secondary industry development has site-specific implications.

5.4.5 Operations

The operational phase of each project plant carries the impact factors discussed above. Problems of solid waste disposal and environmental contamination (air and water systems) will predominate as operations proceed and will accumulate as new plants come on stream.

5.4.6 Environmental Implications

As the foregoing discussion indicates, the effects of one or more *in situ* development will be felt over a large area. While the magnitude of environmental impacts requires more investigation than can be provided in a preliminary overview study, some generalizations can be made.

5.4.6.1 Synergistic and cumulative impacts. Because of the large scale of each *in situ* project, the impacts of a series of projects will be cumulative and, possibly, have synergistic effects as well. An example of synergistic impact would be successive increases in ground level concentrations of toxic compounds from processing operations because of dispersion overlap. Another area of cumulative synergism may concern wildlife; seasonal distributions and abundance may be altered by the first plant, and combinations of successive plants could both re-inforce impact to beyond the threshold or tolerance limit and intensify the severity of impacts on ungulates or other populations. Thus, environmental assessments of the long-term impacts must address questions of cumulative and synergistic impacts. This, we believe, is the fundamental requirement for planning, design criteria, and development of mitigation programs.

5.4.6.2 Sequential disturbance. Disturbance of habitats and populations within the study area will be characterized by progressive disturbance patterns over time. Each plant will gradually expand the operating field and infrastructure without abandonment of central facilities in a systematically planned sequence. This is unlike most developments, such as pipelines or hydro projects, where initial disturbance is reduced during the operational phase and residual disturbance remains at the site of initial impact, enabling accommodation by species which have been displaced or disrupted. Added to the disturbance of a single plant is the sequence of development of new plants over the long-term. Thus, sensory disturbance to affected species and populations will be progressive and cumulative.

The seriousness of this pattern cannot be predicted; however, it is clearly a more disruptive pattern than a defined and circumscribed disturbance. The result may be that disturbance is a more significant impact for *in situ* developments than would normally be expected and its long-term effects may be of equal or greater importance than conventional impacts such as habitat destruction.

5.4.6.3 Ecosystem impacts. Environmental impacts of developments are normally described as low, moderate, and high according to the effects of perturbation on some environmental component. Generally, such effects are direct or indirect and defineable as short- or long-term. Normally, because of either a limited duration of impact or its site-specific nature it is somewhat circumscribed. Such impacts can be described for various resources in the *in situ* production area as specific developments are designed. The Imperial Oil Limited environmental application has a table characterizing possible impacts associated with various activities, a significance rating for each, and proposed mitigative measures. A similar range of specific impacts is expected for each plant in the Fort McMurray area.

Two factors, duration of development and the large scale of resource use, indicate the possibility of fundamental ecosystem effects that are broad and would influence terrestrial and aquatic communities. These potential ecosystem effects warrant further study as they underly a great variety of possible long-term changes. Properly identified, they would more clearly indicate priorities for mitigation research and protective measures.

Specifically, the questions of water withdrawls, disposal, and drainage of large forested areas are examples of potential ecosystem effects. As discussed, a multi-plant scenario may have water requirements exceeding the minimum flow capacity of the Athabasca River. Water use alone could have long-term severe impacts on the aquatic resources of the Athabasca River and its delta. The development of water drainage programs for surface development and water criteria has been referred to earlier. Replication of such drainage programs on a regional basis combined with habitat removal could lead to long-term successional changes in large areas of existing forest communities; in short, development of a new edaphic climax. Attendant changes in the productivity and in biota of terrestrial and aquatic environments would take place. While changes are anticipated, it must be recognized that some species may benefit, while others are impacted negatively. It is important to note, however, that the status quo will change and the implications are broader than those pertaining to individuals of a population affected in a site-specific way.

5.5 HUMAN SYSTEM

The detailed examination of the total social-economic impact of a full commercial *in situ* project will, as in other systems, require extensive modification and re-examination as the development goes from pilot through to commercial. Much of the present research in the human system area is peripheral to the project itself as technology, design criteria, site specific locations, government programs, and developer attitudes will indicate to a large degree the nature, extent, and timing of the human system impact. Government policies and program delivery, for example, on a macro basis will dictate how this project meshes in with other resource projects in the province. Secondly, the issue of a new urban community to accommodate the impact will need to be weighed against the likelihood of other similar projects in the same general location.

Consequently, for the purpose of this report, the impact on the human system will be assessed on a narrow regional scale, and related specifically to the project placement on the Surmont Lease. It will not deal with the broader policy issues of cost-benefit analysis of the project (second and third level) outside the region. It is assumed, therefore, that engineering design, construction management, raw and fabricated materials, etc. can be made available to fit the project's schedule.

Leisure time activities of the construction labour force will have substantial demand on the outdoor recreational capabilities of the region and sub-region. Preliminary examination of the region's outdoor recreation potential has been undertaken and various alternatives presented. Outdoor recreational activity, in our view, must be further examined in relation to two primary criteria:

1. What are the outdoor preferences of a large construction force?
2. How do these preferences relate to the physical capabilities of the land and water systems?

This research should assist in providing policy direction on such items as new park facilities, road access, trapline compensation, and enforcement needs.

Of equal concern with the construction impact is non-authorized use of the land (i.e., squatters). Mitigation measures and policy regulations should be developed such that effective land use control measures are enforced to avoid squatting and its related problems (uncontrolled waste disposal, vegetation damage, fire hazards, etc.). This will be a joint responsibility of the developer and the government, the developer by virtue of his camp accommodation rental policies and the government through its miscellaneous permits for land use.

In planning for the impact of operating manpower, it is vital that the demographic characteristics of the workforce (age, sex, marital status, dependents, etc.) be secured at the earliest possible time. This aggregate profile will have a substantial impact on the nature and level of support infrastructure and support services (both public and private) needed to provide for the primary employment.

The scaling up of the development scenario dealt with the broad overall socio-economic considerations. As stated earlier, the impact on the human system is very much a function of anticipated or approved projects. As such, the authors have attempted to articulate the broad policy issues which must be resolved with each successive plant approval.

6. SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

The foregoing discussion has emphasized the environmental implications within the development region for an individual plant site, and factors to be considered in planning for multiple plants.

From the provincial standpoint, however, impacts arising from the developments may accrue beyond the immediate plant site and oil sands area. Examples are:

1. Effects of water withdrawal on the Athabasca River basin;
2. Dams or inter-basin water transfers that may be necessary to meet supply requirements;
3. Development of supply and transportation corridors; and
4. Mining for coal to meet fuel requirements.

The above examples would have environmental impacts beyond the original *in situ* operations and cannot be ignored in the environmental planning process. The potential for applying an organized research effort to address these issues is not clear.

6.1 MITIGATION CONCEPTS AND POTENTIALS

Mitigation of environmental impacts generally involves five major concepts:

1. Mitigation by avoidance--avoidance of environmentally sensitive areas during construction and operation;
2. Mitigation by design--engineering design to minimize impacts or to meet standards for air or water pollution (e.g., stacks, waste treatment, and erosion control);
3. Rehabilitation--reclamation of disturbed areas and terrestrial and aquatic restructuring of habitats;
4. Mitigation by operational procedure--control of human and operational activities in sensitive areas at important times, generally related to disturbance of wildlife (e.g., aircraft control and motor vehicle control); and
5. Contingency Plans--for limiting damaging from spills, fires, and unforeseen hazards.

All of the foregoing pre-suppose an adequate data base to identify impact potentials and implement an effective mitigation program.

Because of existing legislation, standards for air and water quality and design procedures are well defined. In the *in situ* mining area, particular attention must be given to design standards which deal with cumulative and synergistic impacts on a regional level.

At the individual plant level, proper design of culverts, roads, and erosion control are important measures for minimizing impacts on aquatic environments within a lease.

Mitigation by avoidance can be exercised in circumstances where important resources are affected (e.g., winter ranges for ungulates, nesting sites of raptorial birds). Development, however, if to proceed, constrains opportunities for mitigation by avoidance because of the systematic nature of operations over large areas. Careful study will be required to priorize key resources and adjust development plants to provide the necessary protection.

Rehabilitation or reclamation involves primarily the revegetation of disturbed areas. Revegetation is a vital process in erosion control and also contributes to the early re-establishment of wildlife habitats. In some cases, intensive habitat development is feasible. Within a given lease, however, the feasibility of intensive habitat development is questionable for ungulates because of the widespread disturbance and barriers to movements, which will exist for decades. Any such intensive rehabilitation would best be applied where wildlife populations are viable and able to respond to management. Depending on the species involved, intensive habitat rehabilitation has potential for offsetting unavoidable disturbances. Waterfowl, fish resources, and aquatic furbearers, for example, are responsive to habitat improvement through water control.

Mitigation by operational procedure will be difficult to implement on a large scale because of the nature of *in situ* developments. However, a detailed resource inventory would delineate key times, habitats, and populations which would benefit from protection from disturbance during important periods. Such a program should be established as an integral part of an overall environmental protection program.

Contingency planning is vital in dealing with spills of toxic materials and is well recognized as a protective mechanism. The effectiveness of plans, however, is contingent on the availability of clean-up materials and manpower and the ability to quickly mobilize a clean-up operation. The logistics of contingency plans must be reviewed in terms of their viability to meet emergencies and the adequacy of equipment and materials. Research and planning by regulatory agencies should include forecasts of the vulnerability of various operations and sites within the development area; for example, an oil spill involving water courses is far more serious than a contained terrestrial spill.

Mitigation implicity includes land use planning, particularly in siting of urban centres and in dealing with human activities. An environmental research program must recognize the need for policies and regulations governing human activities and exploitation of resources.

Impacts on existing resource users, such as trappers, will vary according to effects of the development on different furbearing species and interference with trappers' access to traplines. In some cases, access may be improved and trapping efficiency increased. Monetary compensation may be necessary where adverse effects on a trapping operation are unavoidable. Assessments of impacts on trappers require site-specific information on the trapping operation and proposed development activities affecting the trapline.

One of the most significant mitigative measures for *in situ* development would be the development of a wastewater recycling technology to reduce the immense water requirements of a "Huff and Puff" operation. The benefits of such a process would accrue to virtually all environmental components.

6.2 EXTERNAL INFLUENCE ON RESEARCH POLICY

In bringing forward recommendations for identifying deficiencies in the data base and priority areas for further research, the authors are cognizant of several external influences which may dictate the direction and intensity of research.

1. The human socio-economic impact is highly sensitive to present and future government and corporate developer policies.
2. Much of the planning responsibility for the proposed impact and resulting mitigating measures (by way of policy and regulation) rests outside AOSERP's mandate.
3. An *in situ* project at a commercial scale is likely to have a substantial impact on the "men, money, and material" resources of the provincial economy. As such its exact timing and scheduling will have to be meticulously examined and priority given by the approval agencies measured against other industrial projects within the province in an effort to avoid undue strain on the economy.
4. The timing and scheduling of other competing projects, either within the province or in other parts of the country, can seriously alter the proposed Surmont model. This would take place if the model build-up were slower, hence lowering the demand for direct and indirect employment and resulting services.
5. Extraction technology may alter with technological breakthroughs. Consequently the demands for human and physical resources employed in their development will alter, creating a different scenario of possible impacts.
6. Because of the immensity of the Athabasca Oil Sands deposit, development will not, in the foreseeable future, be contingent upon available reserves.

6.3 LIMITATIONS UPON FORWARD PLANNING

To predict the impact of a full scale *in situ* project and to make recommendations on further research and conditions which might mitigate these impacts, several overall considerations must be recognized.

1. Some impacts are easier to predict than others as there may be vast differences between the effects that will occur in the early years and those important a decade later;
2. Some consequences of resource development are controllable, while others are not;
3. Limitations of prediction and planning should recognize that the nature of human affairs often defies planners; and
4. It is unlikely, no matter what control mechanisms are established, that any real control can be exercised over people's lifestyles or habits; problems (such as alcoholism) are beyond anyone's power to control but can generate enormous social costs which are by and large neither measurable or assignable.

6.4 CONCLUSIONS

The previous sections have examined the availability of the resource base, the most likely technologies which may be applied to extract the resource base, and the potential environmental and social impacts which may arise from the development. The following conclusions emerge.

1. Based upon our current understanding of the bitumen resource, the physical extent of the oil sands of the Athabasca deposit do not appear to be a limiting factor in their ultimate development.
2. The most likely technological *in situ* application to be first used is the "Huff and Puff" method.
3. Each *in situ* plant requires the equivalent of 50 c.f.s. of make-up water. Water availability from the Athabasca River would limit the development to five *in situ* plants.
4. Water demand, use, and disposal is the most significant environmental problem of *in situ* development.
5. Cumulative and potential synergistic impacts of toxic air emissions are highly probable for a multi-plant

development scenario. Development of air quality standards should reflect regional long-term requirements.

6. The impact of a series of *in situ* plants will have significant effects on the terrestrial and aquatic ecosystems in the oil sands region.
7. Considerable engineering design work must still be undertaken to fully assess the construction manpower needs as they relate to pilot plant and commercial scale development.
8. A large construction workforce accommodated in a temporary construction camp will create unique service demands on both the physical and human environment when isolated from an established urban centre.
9. An operating workforce of 2,000 people per *in situ* plant is anticipated. A workforce of this magnitude is expected to create a total population of 8,000, which in turn must be domiciled somewhere.
10. The alternatives open for domiciling the anticipated population impacts leads to the conclusion that a new urban centre will be required.
11. Changes will occur in the existing land use patterns through the introduction of a sophisticated transportation and utilities system. These alterations of land use are likely to create compatibility problems that must be examined in detail and ultimately planned for.
12. The new urban alternatives option related to the domiciling of the project's permanent workforce will require substantial analysis in terms of economics and urban planning. Conflicts will arise between the proponent (whose position is likely to support a new urban centre based upon enormous costs of transportation, lost productivity, and broad quality of life considerations) and government whose role is to provide the necessary

support services and, consequently, pay for the services. While these two polarized positions can be and have been measured, the broader downstream benefits to the provincial and national economy are likely to play a significant role in the ultimate resolutions. Therefore, any site specific choice for a new urban alternative should be selected on engineering costs and related physical attributes and constraints and not on the basis of oil sand deposits which may not be exploited because of urban development.

6.5 RECOMMENDATIONS

1. That AOSERP undertake baseline studies to determine the "state of the art" in resource impact assessment as it relates to indirect employment, income, and population multipliers.
2. That a detailed demographic breakdown be undertaken of the pre- and post-Syncrude impact in Fort McMurray.
3. That AOSERP undertake detailed studies with potential developers to identify, as precisely as possible, operating manpower requirements by major plant component (i.e., drilling, upgrading, processing, etc.).
4. That AOSERP approach major developers proposing *in situ* projects in the study area to determine, from engineering design and technological processes, operating manpower sensitivities related to design processes.
5. That AOSERP examine in detail regional and national characteristics of large constuction camps in an effort to develop a profile of their residents, and the habits and needs of these residents.
6. That AOSERP examine the source of saline seepages to the Clearwater and Christina river systems and the associated movement of saline waters in formation.
7. That AOSERP undertake the evaluation of the effects of deep well disposal of waste waters on the movement of saline

waters in receiving formations and adjacent saline water bearing formations.

8. That AOSERP assess the fish productivity of surface waters in the areas having significant bitumen deposits.
9. That AOSERP determine adequacy of available surface and underground water resources for potential plant areas, together with a study of ways and means of augmenting the supply and/or methods of supplying water to the area.
10. That AOSERP examine methods of reclaiming, for further plant use, used waters which have been usually considered waste or unuseable waters.
11. That AOSERP determine methods of reducing evaporation and other losses of water from plant operations.
12. That AOSERP determine the environmental effects of disposal of waste water upon surface waters.
13. That AOSERP determine in detail the nature and amount of air pollutants associated with underground combustion methods of producing raw bitumen, together with the effect on the region's air quality.
14. That AOSERP continue to assess the region's vegetation and its sensitivity to the significant air pollutants.
15. That AOSERP stress the development of a practical and effective program to monitor air quality in the region.
16. That AOSERP continue to undertake baseline wildlife and fish inventories on a lease and regional level, as required, to adequately identify impacts and mitigation potentials. Emphasis should be placed on protection of identifiable populations (e.g., colonial nesting birds, woodland caribou) and critical habitats (winter ranges, calving areas).
17. That AOSERP stress that environmental protection plans must be developed on a lease and regional basis for co-ordinating mitigation and design protection measures

for fish and wildlife and their habitats.

18. That AOSERP sponsor studies on possible long-term successional changes resulting from a multi-plant development.
19. That AOSERP support a regional land use plan incorporating environmental criteria.
20. That AOSERP continue development of a detailed terrain typing map to establish terrain sensitivity and susceptibility to erosion, and to serve as a basis for revegetation planning.
21. That AOSERP sponsor a comprehensive study to determine susceptibility of key species and populations to various types of disturbance (e.g., sensory, human presence, and noise barrier effects). Results should be incorporated into a regional mitigation program with emphasis on critical habitats and populations.

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8. AOSERP RESEARCH REPORTS

1.		AOSERP First Annual Report, 1975
2.	AF 4.1.1	Walleye and Goldeye Fisheries Investigations in the Peace-Athabasca Delta--1975
3.	HE 1.1.1	Structure of a Traditional Baseline Data System
4.	VE 2.2	A Preliminary Vegetation Survey of the Alberta Oil Sands Environmental Research Program Study Area
5.	HY 3.1	The Evaluation of Wastewaters from an Oil Sand Extraction Plant
6.		Housing for the North--The Stackwall System
7.	AF 3.1.1	A Synopsis of the Physical and Biological Limnology and Fisheries Programs within the Alberta Oil Sands Area
8.	AF 1.2.1	The Impact of Saline Waters upon Freshwater Biota (A Literature Review and Bibliography)
9.	ME 3.3	Preliminary Investigations into the Magnitude of Fog Occurrence and Associated Problems in the Oil Sands Area
10.	HE 2.1	Development of a Research Design Related to Archaeological Studies in the Athabasca Oil Sands Area
11.	AF 2.2.1	Life Cycles of Some Common Aquatic Insects of the Athabasca River, Alberta
12.	ME 1.7	Very High Resolution Meteorological Satellite Study of Oil Sands Weather: "a Feasibility Study"
13.	ME 2.3.1	Plume Dispersion Measurements from an Oil Sands Extraction Plant, March 1976
15.	ME 3.4	A Climatology of Low Level Air Trajectories in the Alberta Oil Sands Area
16.	ME 1.6	The Feasibility of a Weather Radar near Fort McMurray, Alberta
17.	AF 2.1.1	A Survey of Baseline Levels of Contaminants in Aquatic Biota of the AOSERP Study Area
18.	HY 1.1	Interim Compilation of Stream Gauging Data to December 1976 for the Alberta Oil Sands Environmental Research Program
19.	ME 4.1	Calculations of Annual Averaged Sulphur Dioxide Concentrations at Ground Level in the AOSERP Study Area
20.	HY 3.1.1	Characterization of Organic Constituents in Waters and Wastewaters of the Athabasca Oil Sands Mining Area

21.		AOSERP Second Annual Report, 1976-77
22.		
23.	AF 1.1.2	Acute Lethality of Mine Depressurization Water on Trout Perch and Rainbow Trout
24.	ME 4.2.1	Air System Winter Field Study in the AOSERP Study Area, February 1977.
25.	ME 3.5.1	Review of Pollutant Transformation Processes Relevant to the Alberta Oil Sands Area
26.	AF 4.5.1	Interim Report on an Intensive Study of the Fish Fauna of the Muskeg River Watershed of Northeastern Alberta
27.	ME 1.5.1	Meteorology and Air Quality Winter Field Study in the AOSERP Study Area, March 1976
28.	VE 2.1	Interim Report on a Soils Inventory in the Athabasca Oil Sands Area
29.	ME 2.2	An Inventory System for Atmospheric Emissions in the AOSERP Study Area
30.	ME 2.1	Ambient Air Quality in the AOSERP Study Area, 1977
31.	VE 2.3	Ecological Habitat Mapping of the AOSERP Study Area: Phase I
32.		AOSERP Third Annual Report, 1977-78
33.	TF 1.2	Relationships Between Habitats, Forages, and Carrying Capacity of Moose Range in northern Alberta. Part I: Moose Preferences for Habitat Strata and Forages.
34.	HY 2.4	Heavy Metals in Bottom Sediments of the Mainstem Athabasca River System in the AOSERP Study Area
35.	AF 4.9.1	The Effects of Sedimentation on the Aquatic Biota
36.	AF 4.8.1	Fall Fisheries Investigations in the Athabasca and Clearwater Rivers Upstream of Fort McMurray: Volume I
37.	HE 2.2.2	Community Studies: Fort McMurray, Anzac, Fort MacKay
38.	VE 7.1.1	Techniques for the Control of Small Mammals: A Review
39.	ME 1.0	The Climatology of the Alberta Oil Sands Environmental Research Program Study Area
40.	WS 3.3	Mixing Characteristics of the Athabasca River below Fort McMurray - Winter Conditions
41.	AF 3.5.1	Acute and Chronic Toxicity of Vanadium to Fish
42.	TF 1.1.4	Analysis of Fish Production Records for Registered Traplines in the AOSERP Study Area, 1970-75
43.	TF 6.1	A Socioeconomic Evaluation of the Recreational Fish and Wildlife Resources in Alberta, with Particular Reference to the AOSERP Study Area. Volume I: Summary and Conclusions
44.	VE 3.1	Interim Report on Symptomology and Threshold Levels of Air Pollutant Injury to Vegetation, 1975 to 1978
45.	VE 3.3	Interim Report on Physiology and Mechanisms of Air-Borne Pollutant Injury to Vegetation, 1975 to 1978

46.	VE 3.4	Interim Report on Ecological Benchmarking and Biomonitoring for Detection of Air-Borne Pollutant
47.	TF 1.1.1	A Visibility Bias Model for Aerial Surveys of Moose on the AOSERP Study Area
48.	HG 1.1	Interim Report on a Hydrogeological Investigation of the Muskeg River Basin, Alberta
49.	WS 1.3.3	The Ecology of Macrobenthic Invertebrate Communities in Hartley Creek, Northeastern Alberta
50.	ME 3.6	Literature Review on Pollution Deposition Processes
51.	HY 1.3	Interim Compilation of 1976 Suspended Sediment Data in the AOSERP Study Area
52.	ME 2.3.2	Plume Dispersion Measurements from an Oil Sands Extraction Plant, June 1977
53.	HY 3.1.2	Baseline States of Organic Constituents in the Athabasca River System Upstream of Fort McMurray
54.	WS 2.3	A Preliminary Study of Chemical and Microbial Characteristics of the Athabasca River in the Athabasca Oil Sands Area of Northeastern Alberta.
55.	HY 2.6	Microbial Populations in the Athabasca River
56.	AF 3.2.1	The Acute Toxicity of Saline Groundwater and of Vanadium to Fish and Aquatic Invertebrates
57.	LS 2.3.1	Ecological Habitat Mapping of the AOSERP Study Area (Supplement): Phase I
58.	AF 2.0.2	Interim Report on Ecological Studies on the Lower Trophic Levels of Muskeg Rivers Within the Alberta Oil Sands Environmental Research Program Study Area
59.	TF 3.1	Self-Aquatic Mammals. Annotated Bibliography
60.	WS 1.1.1	Synthesis of Surface Water Hydrology
61.	AF 4.5.2	An Intensive Study of the Fish Fauna of the Steepbank River Watershed of Northeastern Alberta.
62.	TF 5.1	Amphibians and Reptiles in the AOSERP Study Area.

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