ALBERTA ENVIRONMENT

COLD LAKE - SUBSURFACE FLUID DISPOSAL MEETING

Report 0045 March 27, 1980

E. A. Christiansen Consulting Ltd.

E. A. Christiansen Consulting Ltd.

CONSULTING GEOLOGIST

BOX 3087
SASKATOON, SASKATCHEWAN, CANADA
S7K 3S9

PHONE 374-6700

March 27, 1980

Alberta Environment
Earth Sciences Division
9820 - 106 Street
Edmonton, Alberta T5K 2J6

Attention: Mr. Kerr

Dear Mr. Kerr:

Enclosed is one copy of the material used for my presentation at the Cold Lake - Subsurface Fluid Disposal meetings of March 20 and 21, 1980.

Sincerely yours,

E.A. Christiansen

Alberta 75 1905 1980

ENVIRONMENT

Environmental Protection Services

Earth Sciences Division

403/427-2739

Telex: 037-2006, TWX: 610-831-2636

Oxbridge Place

9820 - 106 Street

Edmonton, Alberta, Canada

T5K 2J6

1980 02 26

E.A. Christiansen
Consulting Ltd.
Box 3087
Saskatoon, Saskatchewan
S7K 3S9

Dear Mr. Christiansen:

Re: Deep Well Disposal

For some time now Alberta Environment has been concerned about the shallow injection of industrial wastes, particularly in the Cold Lake oil sands area. This was reinforced by a recent letter from the Prairie Provinces Water Board concerning the possibility of interprovincial groundwater contamination in that area.

In order to evaluate in more detail the possibilities of such contamination Alberta Environment would like to invite you to attend an informal meeting to exchange ideas on this issue and to suggest avenues for future work that would help clarify the potentiality for groundwater contamination from various sources. Meetings are planned for March 20th and 21st, and we would appreciate your informing us if you would be able to participate.

Yours truly,

H.A. Kerr
Head
Groundwater Branch

hak/bmh
c.c. Dr. Maurice Dusseault
Mr. Don Lennox
Mr. Lloyd Hicklin
Mr. Silver Lupul
Dr. Bill MacDonald
Mr. Tai Yoon
Dr. Chris Gold

March 2, 1980

Mr. H.A. Kerr
Head, Groundwater Branch
Alberta Environment
Oxbridge Place
9820-106 Street
Edmonton, Alberta T5K 2J6

Dear Mr. Kerr:

Thank you for your letter of February 26, 1980.

I accept your invitation to attend an informal meeting to exchange ideas on groundwater contamination to be held March 20 and 21 at your Branch.

Sincerely yours,

E.A. Christiansen

March 10, 1980

Alberta Environment
Environmental Protection Division
Earth Sciences Division
Oxbridge Place
9820 - 106 Street
Edmonton, Alberta T5K 2J6

<u>Attention: Mr. L.D.M. Sadler</u>

Dear Mr. Sadler:

Enclosed are two signed copies of Contract 800766. Item 1 (a) was modified in consultation with Mr. Alan Kerr, and the modified ~~revision~~ version is shown on page 2.

I shall look forward to seeing on March 20.

Sincerely yours,

E.A. Christiansen

This has been submitted to our contract people for approval

Alberta 75 1905 1980

ENVIRONMENT

Environmental Protection Services
Earth Sciences Division

403/427-2739
Telex: 037-2006, TWX: 610-831-2636
Oxbridge Place
9820 - 106 Street
Edmonton, Alberta, Canada
T5K 2J6

1980 02 26

E.A. Christiansen
Consulting Ltd.
Box 3087
Saskatoon, Saskatchewan
S7K 3S9

Attention: E.A. Christiansen

Re: Contract 800766
<u>Cold Lake-Subsurface Fluid Disposal</u>

<u>Background</u>

A review of applications for disposal of waste fluids at depths of 2000 feet and shallower are undertaken by both the ERCB and Alberta Environment. Alberta Environment is concerned with possible pollution of shallow aquifers through uncontrolled movement of these waste fluids.

The purpose of the meeting on March 20 and 21 is to discuss the possible effects of such disposal and to make recommendations to senior Environment staff concerning the level and content of application review.

Therefore in regard to the above I understand our Allan Kerr has made the following arrangements with you:

1) Mr. E.A. Christiansen of your firm will:

* a) Perform consulting services to review, discuss and make recommendations concerning subsurface fluid disposal in the Cold Lake area.

b) Make a short presentation to the group assembled March 20 on your general understanding of the area and the problem as presented in the Background statement.

c) Assist in drafting recommendations to senior Department staff.

2) Allan Kerr of Alberta Environment will be the project supervisor who is authorized to issue directives under this contract and is authorized to terminate this contract.

* See next page for 1 (a)

3) This contract comes into effect on March 1, 1980 and the services shall be completed on or before March 31, 1980.

4) All discussions concerning this project are confidential and are only to be discussed with those involved in the project unless approved by Allan Kerr.

5) Your fee for these services will be charged on a rate of $50.00 per hour up to a maximum of $4,000.00, upon satisfactory completion of this contract; the fee shall include all costs of operation unless authorized otherwise by L.D.M. Sadler.

6) The invoice for this service is to be forwarded for approval to Allan Kerr at the following address: Alberta Environment, Earth Sciences Division, 9820 - 106 Street, Edmonton, Alberta, T5K 2J6.

7) This contract inures to the benefit and is binding upon the parties to this contract and their respective successors and assigns.

Yours truly,

L.D.M. Sadler
Director
Earth Sciences Division

hak/bmh

If the foregoing represents your understanding of the arrangements made and you are in agreement, please sign this letter in the space provided for your signature, retain one for your records and return the signed letter to Allan Kerr.

E A Christiansen ________ Date March 10/80

E.A. Christiansen

* 1 (a) Perform consulting services to review, discuss and make recommendations concerning subsurface fluid disposal in the Cold Lake area as it pertains to disturbance of bedrock by glacial thrusting and collapse, to the nature of the bedrock surface, and to potential aquifers in glacial deposits and preglacial valleys.

ALBERTA ENVIRONMENT
Contract Cover Sheet

Contract Number: 8 0 0 7 6 6

Assignment #
Amendment #

Vendor Name and Address: E.A. Christiansen Consulting Ltd. Box 3087 Saskatoon, Saskatchewan S7K 3S9

Project Name: COLD LAKE FLUID DISPOSAL

Division: Earth Sciences
Branch: Groundwater
Project Manager: H.A. Kerr

Amount $: 4,000.00
Contract Type: Letter
Selection by: IV

Amended $:
Date:
Contract Signed by: L.D.M. Sadler

Effective date: March 1/80 amended
Wk. Compl. date: March 31/80 amended
Date of Contract: amendment
Holdback %: 0
Certification Officer: H.A. Kerr
Expenditure Officer: H.A. Kerr

Commit ☐ Do not Commit ☐ Assignment ☐
Input Code: W0502 Special Funding ☐
Expenditure Code: 300
Change or Amendment Items

		date
Initiated by	H.A. Kerr	Feb. 25/80
Contents Approved		
Form Approved		
DM/ADM Approved		
Returned to Division		
Returned to CAU		
Entered		

RECORD OF PAYMENTS

INVOICE NO.	TRANSATOR NO.	AMOUNT	HOLDBACK	BALANCE

Alberta 75 1905 1980

ENVIRONMENT

Environmental Protection Services
Earth Sciences Division

403/427-2739
Telex: 037-2006, TWX: 610-831-2636
Oxbridge Place
9820 - 106 Street
Edmonton, Alberta, Canada
T5K 2J6

1980 02 27

Dr. E.A. Christiansen
E.A. Christiansen Consulting Ltd.
Box 3087
Saskatoon, Saskatchewan
S7K 3S9

Dear Dr. Christiansen:

I am sending you some of the information we have available concerning the potential for interprovincial aquifer contamination in the Cold Lake area. Some items will have to be sent later, I am afraid, but I hope you will find these ones helpful prior to our meeting in March.

I enclose:

- the available deep well disposal files, together with an index
- our bibliography on deep well injection
- our bibliography on hydraulic fracturing
- R.F. Jackson's report to the Prairie Provinces Water Board.

Four of the deep well files will be sent in a few days, as will an index of Riley's oil and gas well logs for the area.

Looking forward to seeing you next month.

Yours truly,

C. Gold

Christopher Gold
Groundwater Branch

cg/bmh
att'd

Cold Lake Disposal Well Index

File	File #	Correspondence Files	Reports	Maps & Logs
+ Canadian Industries Gas & Oil	8853	1		4
+ BP Canada-Cold Lake	770913	1		
+ BP Exploration Canada-Cold Lake	2469	1		2
+* BP Exploration Canada	790707	1		
* Pacific 66, Muriel Lake	790509	1	1	
World-Wide Energy, Fort Kent	770363	1		1
Norcen-Primrose	9106	1		
Murphy Oil-Lindbergh	8987	1		2
Murphy Oil-Lindbergh	8021	1		2
Imperial Oil-Liming	780177	1		
Ashland Oil-Cache Lake	9830	1		
Chevron Standard-Cold Lake	780324	1	1	3
Chevron Standard-Cold Lake	770508	1	1	2
Chiefton-Craigend	780465	1		
Gulf Oil-Cold Lake	770280	1		4

- Files marked + will be forwarded in a few days
- Files marked * are copies of the originals and need not be returned
- All original files must be returned at the completion of the contract

Alberta 75 1905 1980

ENVIRONMENT

Environmental Protection Services
Earth Sciences Division

403/427-2739
Telex: 037-2006, TWX: 610-831-2636
Oxbridge Place
9820 - 106 Street
Edmonton, Alberta, Canada
T5K 2J6

1980 03 05

Dr. E.A. Christiansen
EA Christiansen Consulting Ltd.,
Box 2087
Saskatoon
Saskatchewan S7K 3S9

Dear Dr. Christiansen,

I am enclosing the four remaining deep well disposal files I promised you, together with the index to Riley's oil and gas well logs for the Cold Lake area, and our water well index for the same area.

Two copies of our contract with you have been sent to you under separate cover. Please sign them and return one copy.

Yours sincerely,

C. Gold

Christopher Gold
Groundwater Branch

CG/cak

Enclosure

INFORMATION ON DISPOSAL SITES PROVIDED
by
ALBERTA ENVIRONMENT

Gulf Cold Lake 1-14-65-2-W4

SOBC Beaver Crossing 8-36-61-2-W4

Chiefco BluCr. Craigend 3-28-64-12-W4

Pacific *et al.* Muriel 7-22-59-4-W4

SOBC Beaver Crossing 16-36-61-2-W4

Fina Cache 10-18-58-11-W4

BOCO *et al.* Lindbergh 4-14-58-5-W4

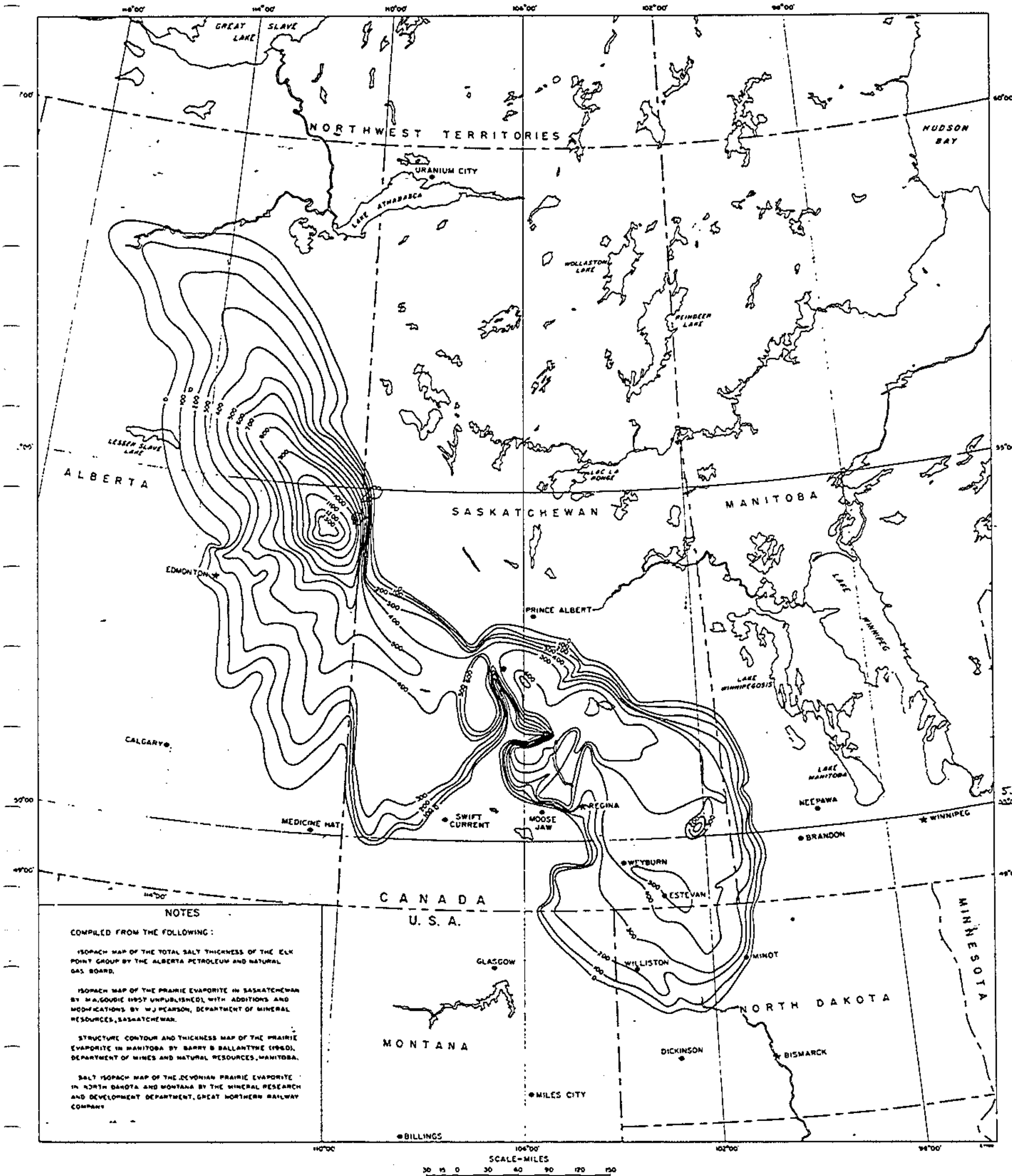
CIGOL WD Primrose Ex 10-6-66-1-W4

WECO Fort Kent SWD 5A-28-61-4-W4

IMP 1-78 Cold Lake OV 4-17-65-3-W4

IMP 2-78 Cold Lake OV 11-7-65-3-W4

Murphy BOCO PI-3 Lind Ex 5-13-58-5-W4



53°
106°

FIGURE 17

ISOPACH MAP SHOWING THE TOTAL THICKNESS OF THE SALT IN THE ELK POINT GROUP

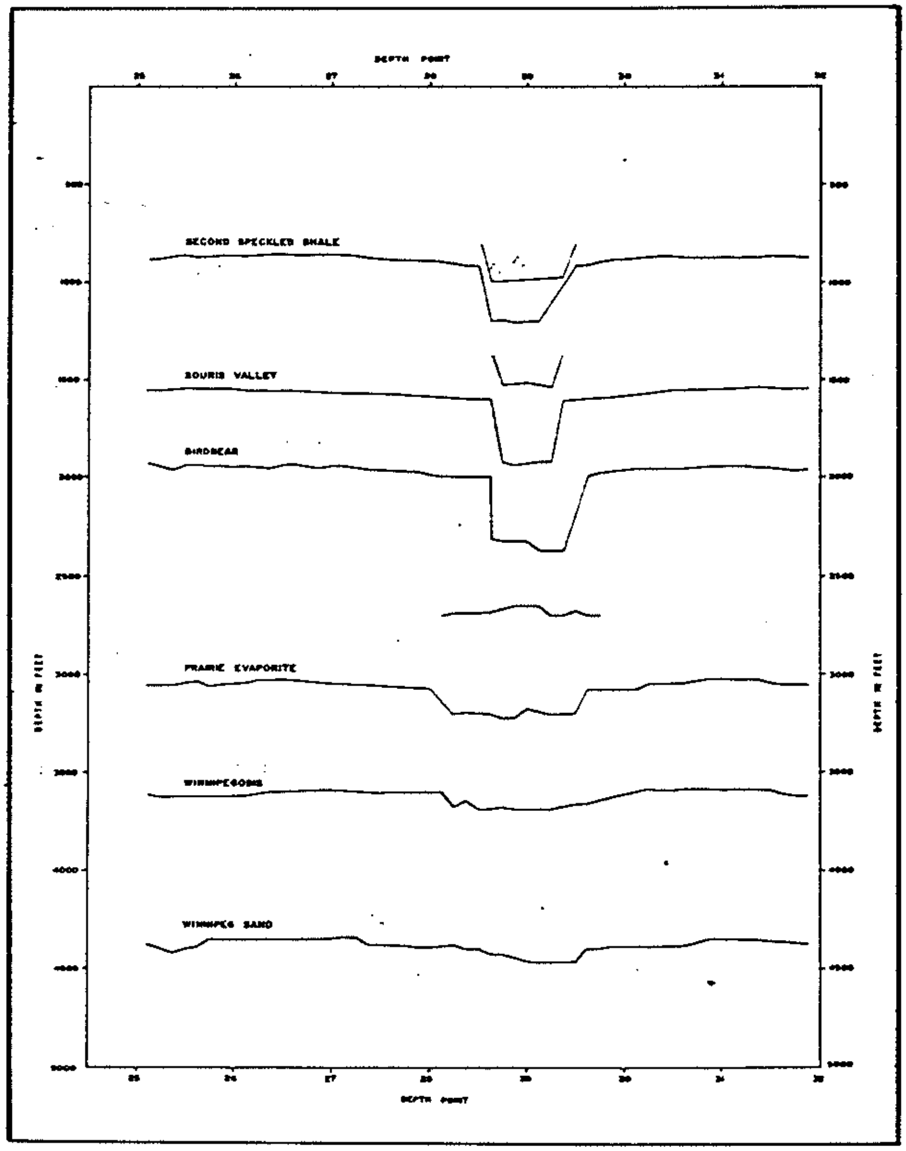


Figure 0013-002-16. Seismic cross section showing that the Crater Lake structure is the result of removal of salt from the Devonian Prairie Evaporite Formation. From Gendzwill and Hajnal (1971).

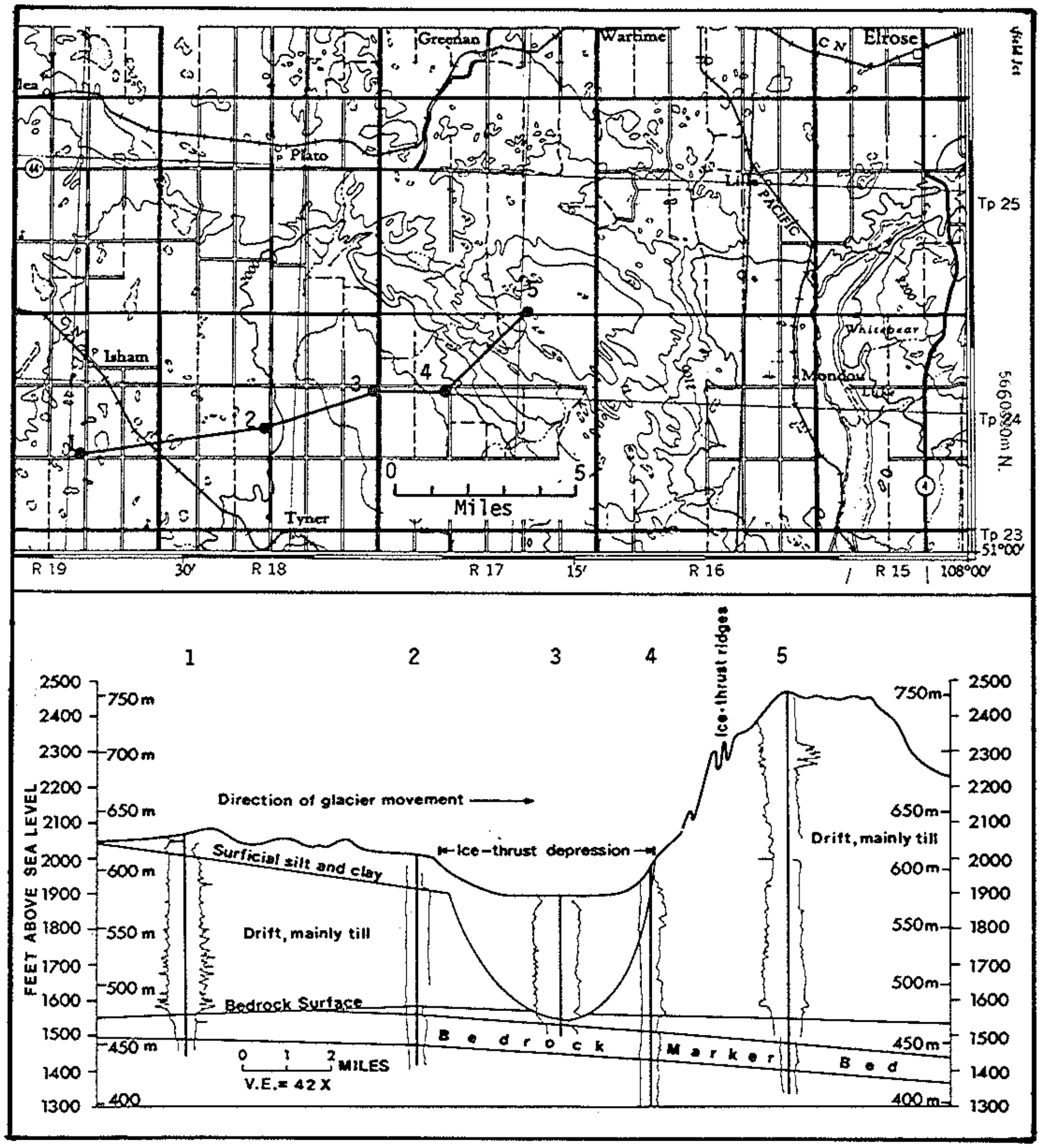


Figure 5. Ice-thrust depression northeast of Tyner, Saskatchewan.
From Christiansen and Whitaker (1967).

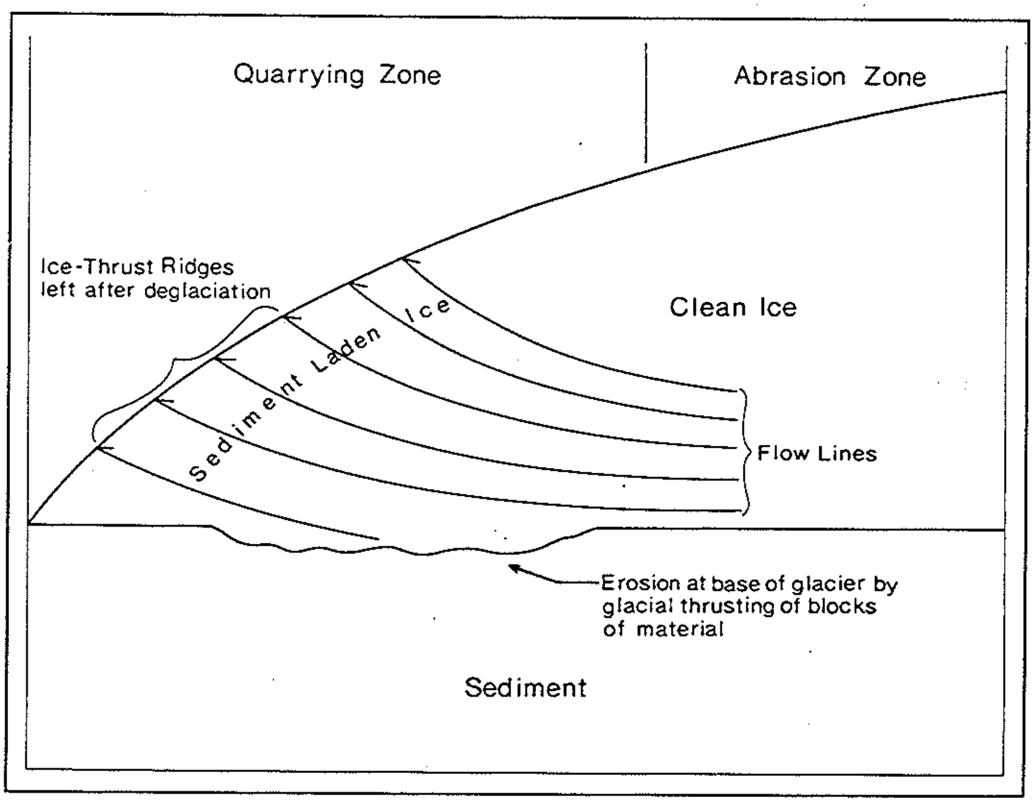


Figure 4. Schematic diagram showing the process of glacial thrusting. From Clayton and Moran (1974).

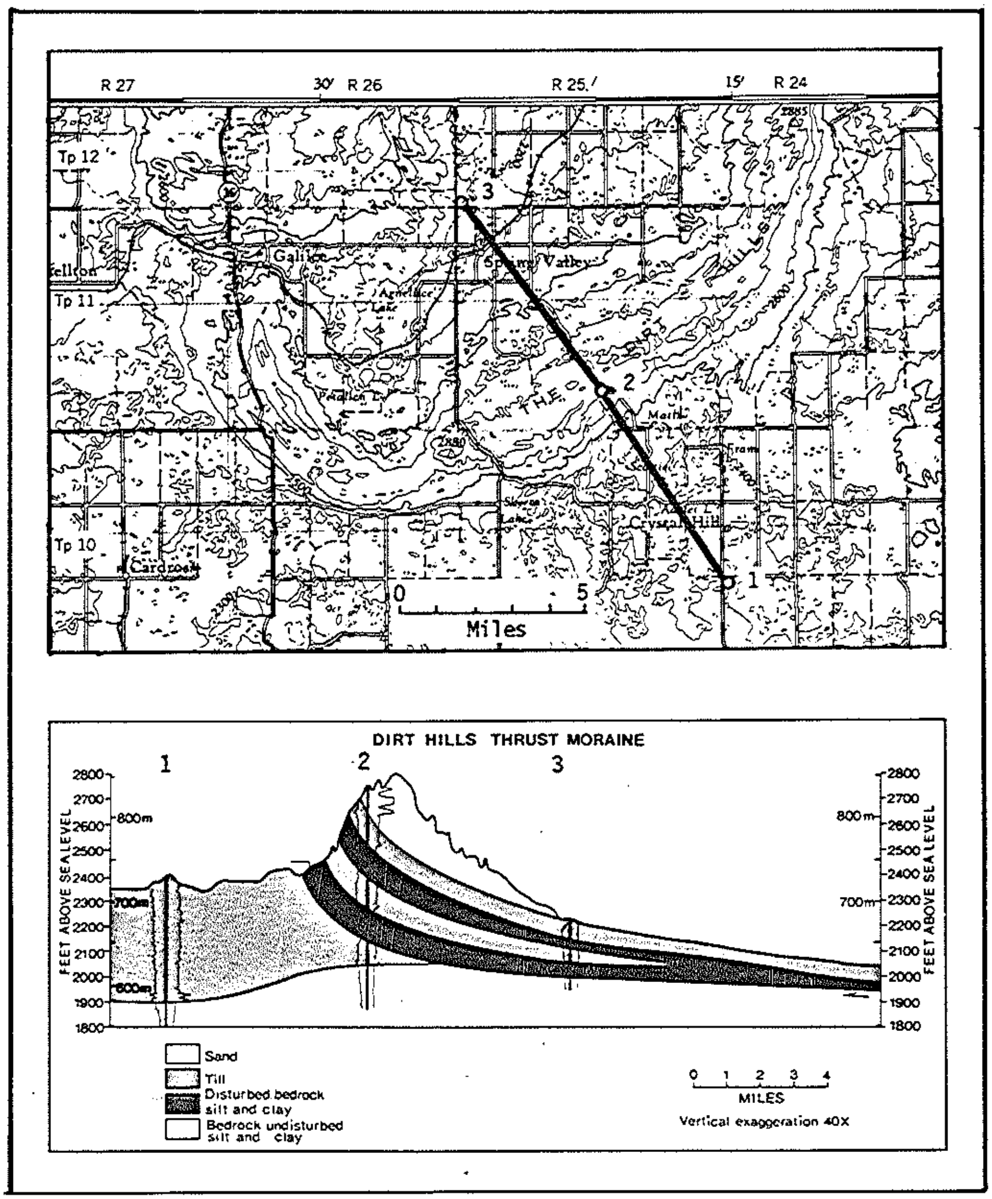


Figure 0013-002-15. Repetition of drift and bedrock by glacial thrusting in the Dirt Hills Moraine, 30 miles south of Moose Jaw, Saskatchewan. From Christiansen and Whitaker (1976).

ON

THE PROBABLE IMPACT OF THE COLD LAKE PROJECT ON INTERPROVINCIAL AQUIFERS

R. E. Jackson
National Hydrology Research Institute
562 Booth St., Ottawa, Ontario; K1A 0E7

August 1979

This report was prepared for, and at the request of, the Prairie Provinces Water Board.

SUMMARY

The effect of the Cold Lake (Alberta) Oil Sands Project on the quantity and quality of ground water in a nearby interprovincial aquifer is considered.

The interprovincial aquifer in question is a sand and gravel, buried-valley aquifer known in Saskatchewan as the Hatfield Valley Aquifer. Because of both the insufficient quantity and the poor boiler-water quality of the ground water in this aquifer, Imperial Oil Ltd. has no intention of abstracting significant quantities of ground water for the Project. The principal adverse effects on this aquifer therefore concern the possibility of a deterioration in the ground-water quality due to potential contamination by proposed waste-management operations both on the surface and involving deep-well disposal. Any such contamination of the aquifer is assumed to be unacceptable. Proper waste-management practices are to be applied to the storage of solid wastes on the surface and, as a consequence of this, the downward migration of leachates to the interprovincial aquifer should be prevented.

Unresolved risks remain, however, with the intent of Imperial Oil Ltd. to dispose of some 2000 imp. gpm of toxic waste water for 25 years by deep-well disposal involving, if necessary, the hydraulic fracturing of the disposal formation. Such disposal will result in the migration of the waste waters an average distance of 0.4 miles or 650 metres from each of 12 disposal wells over the 25-year lifetime of the project, however dispersion in the disposal formation will result in a greater maximum distance. While the migration of the wastes in the disposal formation may not be of interprovincial consequence, there is a distinct possibility that under injection pressures which cause hydraulic fracturing waste waters may migrate through or around improperly finished boreholes or disposal wells penetrating the disposal formation or through fractured confining beds and thence into the interprovincial aquifer ("the Sarnia Syndrome").

It is recommended that (1) a study be undertaken of the proposed deep-well injection program by a hydrogeologist(s) familiar with the Western Canada sedimentary basin and the proposed method of deep-well waste disposal and (2) clarification be sought on the intentions of Imperial Oil Ltd. and Alberta Environment to install observation-well networks in, respectively, the disposal formation and the buried-valley aquifers.

INTRODUCTION

The purpose of this report is to comment on the probable impact that the Cold Lake (Alberta) Oil Sands Project of Imperial Oil Ltd. might have on the quantity and quality of ground water in interprovincial aquifers.

The Cold Lake Project is designed to recover 160,000 barrels per day of bitumen from approximately 8,000 dual purpose, steam-injection/oil recovery wells. For every 1 unit of upgraded crude oil (140,000 bpd) produced at the Project site 0.6 units of waste are to be disposed by deep-well injection methods and 1.2 units are to be disposed to surface waters. Furthermore solid-waste landfills, sulfur piles and ash-disposal areas resulting from the Project pose additional, potential threats to the interprovincial aquifers of the Cold Lake Area.

The interprovincial aquifers of the Canadian Prairies with ground waters of potable quality are generally known as bedrock-valley aquifers (see Figure 1). They are composed of sand and gravel and are situated in valleys cut into the bedrock by preglacial ancestors of the present Saskatchewan river system. They are generally overlain by relatively impermeable glacial till and are underlain by thick sequences of less permeable sedimentary rocks (see Figure 2). They comprise "the most important aquifer in southern Saskatchewan" (Whitaker and Christiansen, 1972), albeit an undeveloped one NW of the N. Saskatchewan River, as well as in the Cold Lake area of Alberta (Yoon et al., 1977). In the present case only one interprovincial aquifer is of concern -- the Hatfield Valley of Saskatchewan and its Alberta counterpart. Because of the importance that this aquifer might have in the future development of the Prairie Provinces, *it is assumed, a priori, that any contamination of is unacceptable.*

ANALYSIS

Concerning the effect of the Cold Lake project on the quantity of ground water flowing in the interprovincial aquifer, Imperial Oil Ltd. in its Draft Final Environmental Impact Assessment (DFEIA, 1978) stated that:

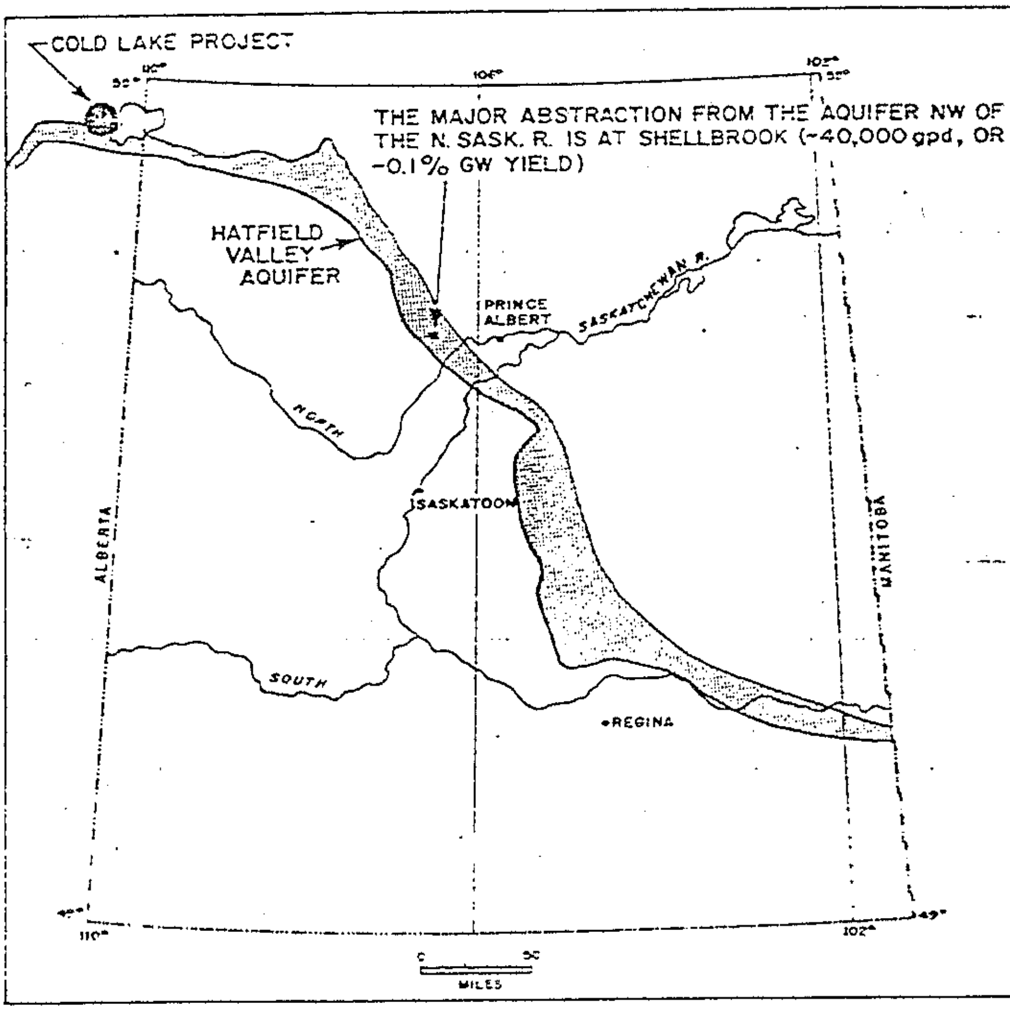


FIGURE I. THE HATFIELD VALLEY AQUIFER

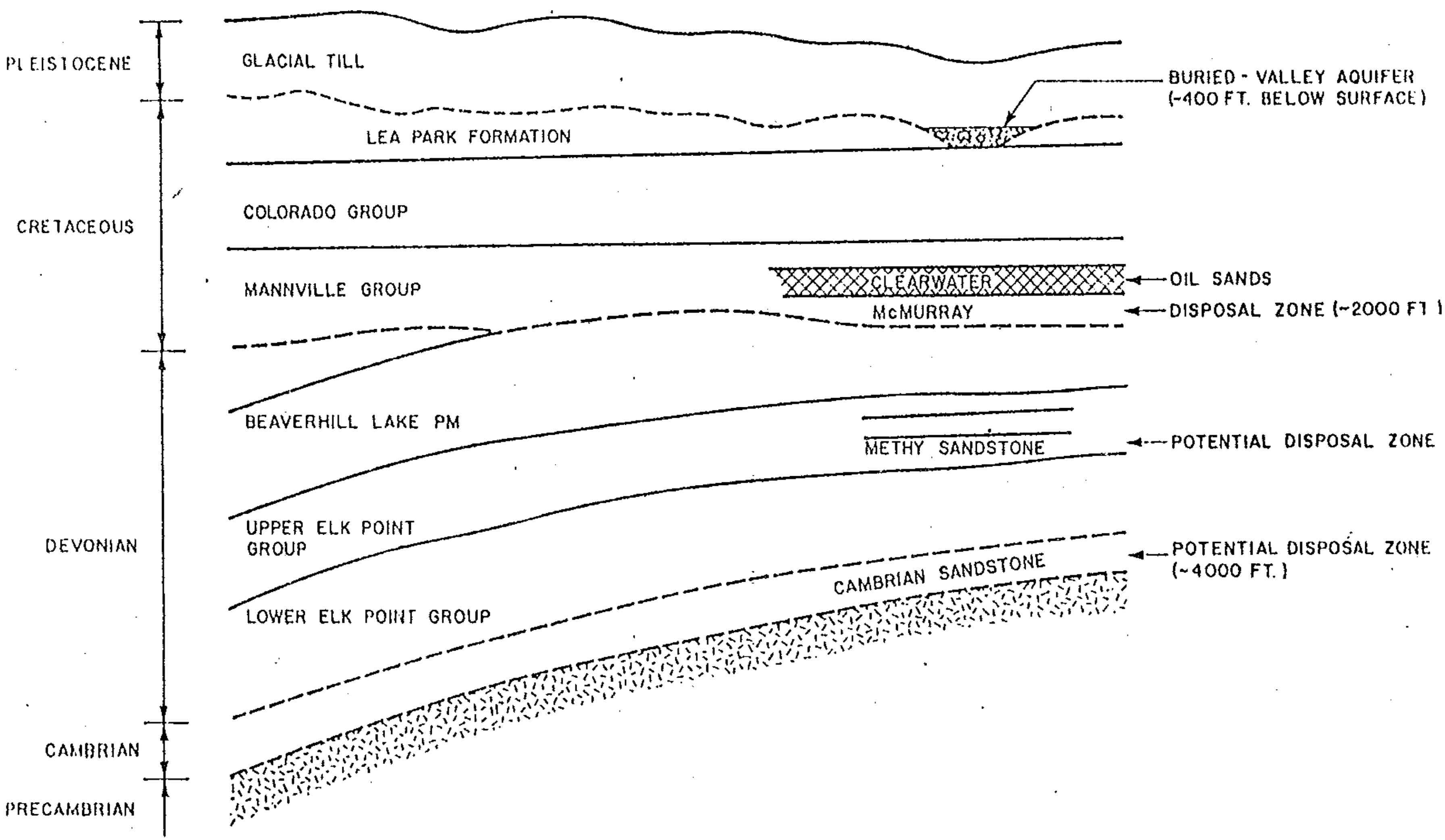


FIGURE 2. SCHEMATIC GEOLOGICAL CROSS SECTION
COLD LAKE AREA

> "...the potential supply from aquifers is considerably less than the project requirements. Furthermore, water from near surface aquifers is very hard and would require considerable treatment for boiler feedwater" (DFEIA, p.59).

Consequently, unless the July 31 interim decision of the Alberta Energy Resources Conservation Board (AERCB) forces Imperial to reappraise and then adopt ground water as a source of water for the project, the *quantity* of ground water in the interprovincial aquifer should not be affected.

Therefore the potentially adverse effects on the interprovincial aquifer are those concerning ground-water quality. In particular the threats are posed by two types of waste-management operations -- (1) waste-management areas on the surface from which leachates might migrate downwards to the buried-valley aquifers and (2) the deep-well disposal of waste waters to formations beneath the buried-valley aquifer.

The potential exists for the interprovincial aquifer to become contaminated from the downward migration of leachate (from landfills, sulfur piles and ash dumps) through fractures in the glacial till. However the standard waste-management practice of lining waste-disposal areas with impermeable bottoms and treating the leachate produced should minimize this danger.

Consequently the threat posed in the interprovincial aquifer is mainly that arising from the injection of liquid wastes by means of deep (~2000 feet) disposal wells.

It is the intention of Imperial Oil Ltd. to inject 84,000 barrels of waste water per day into the McMurray formation for a period of 25 years at wellhead pressures of up to 1000 psi. The waste water is predominately a NaCl water with significant quantities of toxic substances such as phenols, cyanides, sulfites and vanadates (DFEIA, pp. 619-621).

The McMurray formation is a sandstone approximately 200 feet thick (DFEIA, p. 169), with an average permeability of "greater than 1 darcy" (> 10^{-3} cm/s at 20°C) in the basal 100 foot unit (Exhibit 3, Question 1, page 3, submitted to December 1978 AERCB hearings). It is a saline aquifer (total dissolved solids ~ 10,000 ppm) which will be irreversibly contaminated by this disposal operation. The author is aware of no other possible uses for this formation.

The injection is to be accomplished by fracturing the disposal formation, if necessary, with the applied hydraulic pressure (bottom-hole pressures up to 1700 psi). From each of 12 disposal wells the injected wastes will migrate an average distance of 0.4 miles (~650 metres) through the disposal formation over the 25-year lifetime of the project (see Appendix), however the maximum distance produced by dispersion of the wastes may be one or even two orders of magnitude farther.

Not only is it the intent of Imperial to hydraulically fracture the disposal formation if necessary, it is also their intent to fracture the overlying oil sands by steam injection (DFEIA, p.7). In his study "Subsurface Disposal of Waste in Canada" van Everdingen (1974) of IWD Calgary commented

> The technique of hydraulic fracturing should not be used to increase the receptive capacity of a waste disposal formation, because of the inherent risk of causing damage to overlying or underlying confining beds.

Because of the low permeability of the McMurray formation, wellhead injection pressures approximately twice the maximum recorded in Canada (Vonhof and van Everdingen, 1973) may be employed. With such high applied pressures upward migration of the waste waters may occur (1) through fractured confining beds, (2) around improperly-grouted disposal wells or (3) up improperly-plugged or around improperly-grouted exploration boreholes penetrating the disposal formation. This third possibility has been considered by Imperial (Exhibit 20, Question 1, page 7 submitted to December 1978 AERCB hearings):

> "...the possibility of communication to the [buried-valley] aquifers, approximately 400 m (1300 feet) above the injection zone is extremely remote."

It is recommended that the Prairie Provinces Water Board seek a second and independent opinion on all three of the above possibilities from a hydrogeologist (or hydrogeologists) familiar with deep-well waste disposal and the Western Canada Sedimentary Basin. (N.B. Vandenburg et al. (1977) reported that there is evidence to suggest that unplugged or improperly abandoned wells may be leading to the contamination of buried-valley aquifers in the Sarnia area of Ontario by deep-well injected wastes.). In light of what has been said it is encouraging to note the AERCB interim decision (dated July 31, 1978) that Imperial inject their wastes into the deeper (~4000 ft) Cambrian sandstones and not the McMurray formation (unless Imperial can show it is "impractical").

DISCUSSION

From the literature made available to the author by Imperial Oil Ltd. (principally DFEIA and Exhibits 3 and 20) several uncertainties remain unresolved and are of concern:

(1) It is far from clear how much basic information exists regarding the disposal formation:

> "Subsurface disposal of liquid wastes should only be allowed after extensive studies of the hydrodynamic, hydrogeologic and hydrochemical environments have shown that no hazards are apparent" (Vonhof and van Everdingen, 1973).

Given this uncertainty it is not clear how far the wastes might migrate in the disposal formation and in what direction.

(2) As already mentioned, the possibility of interformational flow resulting in the contamination of the interprovincial aquifer has not been thoroughly discussed in either the DFEIA or Exhibit 3. In particular it is important that the number, location and state of exploration boreholes drilled into the disposal formation be known so that the liklihood of interformational flow (see pp. 6-7, Exhibit 3, Question 1) may be assessed. Furthermore nothing is said concerning the construction of the disposal wells; it is particularly important that a third casing be set from the surface to beneath the buried-valley aquifers and be cemented from shoe to surface as is shown in Figure 5 of van Everdingen and Freeze (1971, p.21).

(3) The chemical interactions between the waste waters and both the disposal-formation rock and the buried-valley aquifer sediments have not been considered. Without studies of such interactions (e.g. using laboratory columns) it is impossible to assess the attenuation of the waste waters in either the disposal formation or the interprovincial aquifer should it become contaminated. Consequently it is not known whether or to what extent chemical reactions will cause the plugging of the disposal formation, nor is it known how mobile the toxic components of the wastes might be in the aquifer.

(4) Finally, observation-well networks must be installed in both the disposal formation and the interprovincial aquifer. Imperial have indicated their intention of monitoring the "aquifer response and water quality in the McMurray formation throughout the life of the project" (DFEIA, p. 232), however recent discussions between Imperial and IWD cast doubt on this (memo of L. Wiens, IWD Regina, to R.P. Baldwin, IWD Regina, dated June 19, 1979). Furthermore, although it is the intention of Alberta Environment to install an observation-well network in the buried-valley aquifers near the Cold Lake Project (Yoon et al., 1977), so far there are only 3 observation wells in place with another 6 intended for installation when funds are provided (Yoon, T.N., Alberta Environment, pers. comm.). Suffice it to say that 9 observation wells is a minimum number by which to monitor ground-water quality variations over so large an area when the bedrock-valley aquifers are of 100-200 feet in thickness.

RECOMMENDATIONS

In order to reduce the uncertainties identified in the Discussion above it is recommended that:

(1) a study be undertaken by a hydrogeologist (or hydrogeologists) familiar with the techniques of deep-well waste disposal and with the hydrogeology and geochemistry of the Western Canada sedimentary basin to

(a) examine the basic data concerning the hydrogeology and hydrochemistry of the disposal formation in order to determine the probable migration pattern and chemical interactions within the disposal formation,

and (b) determine the potential for upward migration of the waste waters to the interprovincial aquifer through fractured confining beds or improperly finished exploration boreholes or disposal wells, given the proposed method of disposal.

(2) clarification be sought from Imperial Oil Ltd. and Alberta Environment on their intentions to install observation-well networks in, respectively, the disposal-formation and the interprovincial aquifer.

REFERENCES

DFEIA, 1978. Draft Final Environmental Impact Assessment for Imperial Oil Ltd. Cold Lake Project. Volume 1, Biophysical Resources, dated August 1978. Imperial Oil Ltd., Calgary, Alberta. AERCB Application No. 770866.

Vandenburg, A., Lawson, D.W., Charron, J.E. and Novakovic, B., 1977. Subsurface Waste Disposal in Lambton County, Ontario. Tech. Bull. No. 90, Inland Waters Directorate, Ottawa, 64 p.

van Everdingen, R.O., and Freeze, R.A., 1971. Subsurface Disposal of Waste in Canada. Tech. Bull. No. 49, Inland Waters Directorate, Ottawa, 63 p.

van Everdingen, R.O., 1974. Subsurface Disposal of Wastes in Canada-II, Disposal-Formation and Injection-Well Hydraulics. Tech. Bull. No. 78. Inland Waters Directorate, 30 p.

Vonhof, J.A. and van Everdingen, R.O., 1973. Subsurface Disposal of Liquid Industrial Wastes. CIM Trans., LXXVI, pp. 120-126.

Whitaker, S.M. and Christiansen, E.A., 1972. The Empress Group in Southern Saskatchewan, Can. J. Earth Sci., 9, pp. 353-360.

Yoon, T.N., Goble, K.A. and Carlson, V.A., 1977. Groundwater Resources in the Cold Lake Oil Sands Area. In Oil Sands of Canada and Venezuela, CIM Special vol. 17, pp. 103-132.

APPENDIX

Calculation of the average migration distance of injected waste.

From van Everdingen (1974) the average radial migration distance of the injected waste for each of the 12 disposal wells is given by

$$(r_e) \text{ miles} = 0.0236\ [q_T' \ T/H\ \phi]^{1/2}$$

where q_T' is the injection rate in thousands of US gallons per day, T is the time in years, H is the formation thickness in feet and ϕ is the porosity as a fraction.

Representative values are:

$q_T' = 84{,}000 \text{ bpd}/_{12} = 294 \times 10^3 \text{ US gpd}/_{\text{well}}$

T = 25 years (i.e. project lifetime)

H = 100 ft. (thickness of basal McMurray formation)

ϕ = 0.25 (from Exhibit 20 submitted to AERCB)

Therefore r_e = 0.4 miles or ~650 metres.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

Informational Letter
IL-OG 77- 4

TO: All Oil and Gas Operators

APPLICATIONS - SUBSURFACE WATER DISPOSAL SCHEMES

The Board has revised its requirements regarding the handling and content of certain applications for subsurface liquid disposal schemes under section 38 of The Oil and Gas Conservation Act. In lieu of a detailed application, consideration will now be given to a simple application for those subsurface disposal schemes that comply with certain criteria listed in a proposed revision of section 15.070 of the Oil and Gas Conservation Regulations, a copy of which is attached. The information required in both the simple and detailed applications is also listed in the revised section 15.070 of the Regulations. A sample format to be followed in the submission of a simple application is illustrated in Appendix I.

Alberta Environment has also agreed that only schemes injecting plant waste or large volumes of fresh water will, in the future, be referred to the Department and will require Ministerial Approval.

Any questions concerning this Informational Letter shall be directed to Mr. L. E. Hicklin of the Board's Development Department.

ISSUED at Calgary, Alberta on 16 March 1977.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

Attachments

Water Disposal

15.070 (1) A simple application for subsurface disposal under section 38, clause (c) of the Act that complies with the conditions set out below, shall be made in accordance with subsection (2)

(a) produced water shall be returned to the zone of origin, or to a formation below 2,000 feet K.B.,

(b) in the disposal formation,

(i) there is no oil or gas, or

(ii) the top of the injection interval is 10 feet or more below the gas/water or oil/water interface,

(c) where the disposal pool or formation contains oil or gas, the monthly volume of injected water, shall not exceed the total reservoir volume of gas, oil and water produced from the wells completed in that pool or formation,

(d) if the disposal formation contains oil or gas, the mineral owners in the pool or formation within a one-mile radius of the disposal well have agreed to the scheme,

(e) the sum of the hydrostatic head of the fluid column in the well and the maximum surface injection pressure shall not exceed 90 per cent of the formation fracture pressure,

(f) there are no open perforations above the packer in the tubing-casing annulus,

(g) the tubing-casing annulus shall be filled with inhibited fluid,

(h) a packer shall be set within 50 feet of the top of the injection interval,

(i) the casing above the packer was successfully pressure tested to 1,000 pounds per square inch gauge for 15 minutes,

(j) the total solids content of the water in the disposal formation is greater than 10,000 parts per million.

(ii) completion details of the proposed disposal well including,

(A) the depth of the packer,

(B) existing completion interval and the proposed disposal interval, and

(C) the inhibited fluid to be used in the annulus,

and

(iii) the measurement and water handling facilities,

and

(c) a tabulation of

(i) reservoir parameters including vertical and horizontal permeabilities, aquifer and pool thickness,

(ii) the virgin reservoir, bubble point and current reservoir pressures,

(iii) the results of the material balance calculations to show anticipated interface movements and drive indices,

(iv) pool production history,

(v) water/oil ratios and production history of the disposal well and the first two rows of off-set wells,

(vi) surface, bottom hole injection and formation fracture pressures,

(vii) estimated monthly injection volume, and

(viii) analysis of the water in the disposal formation.

APPENDIX I

Example - Simple Application

Energy Resources Conservation Board
603 - 6th Avenue S.W.
Calgary, Alberta
T2P 0T4

Attention: Development Department

Dear

SUBSURFACE WATER DISPOSAL
WELL NAME AND LOCATION
FIELD OR AREA

In accordance with section 15.070, subsections (1) and (2) of the Oil and Gas Conservation Regulations, A.B. Oil Company Ltd., applies for approval of a scheme to dispose of produced water by injection into the Nisku Formation through the above well.

The scheme complies with the criteria set out under section 15.070, subsection (1) of said Regulations. The attached schematic diagram contains the information required under section 15.070, subsection (2) of the Regulations.

Yours truly

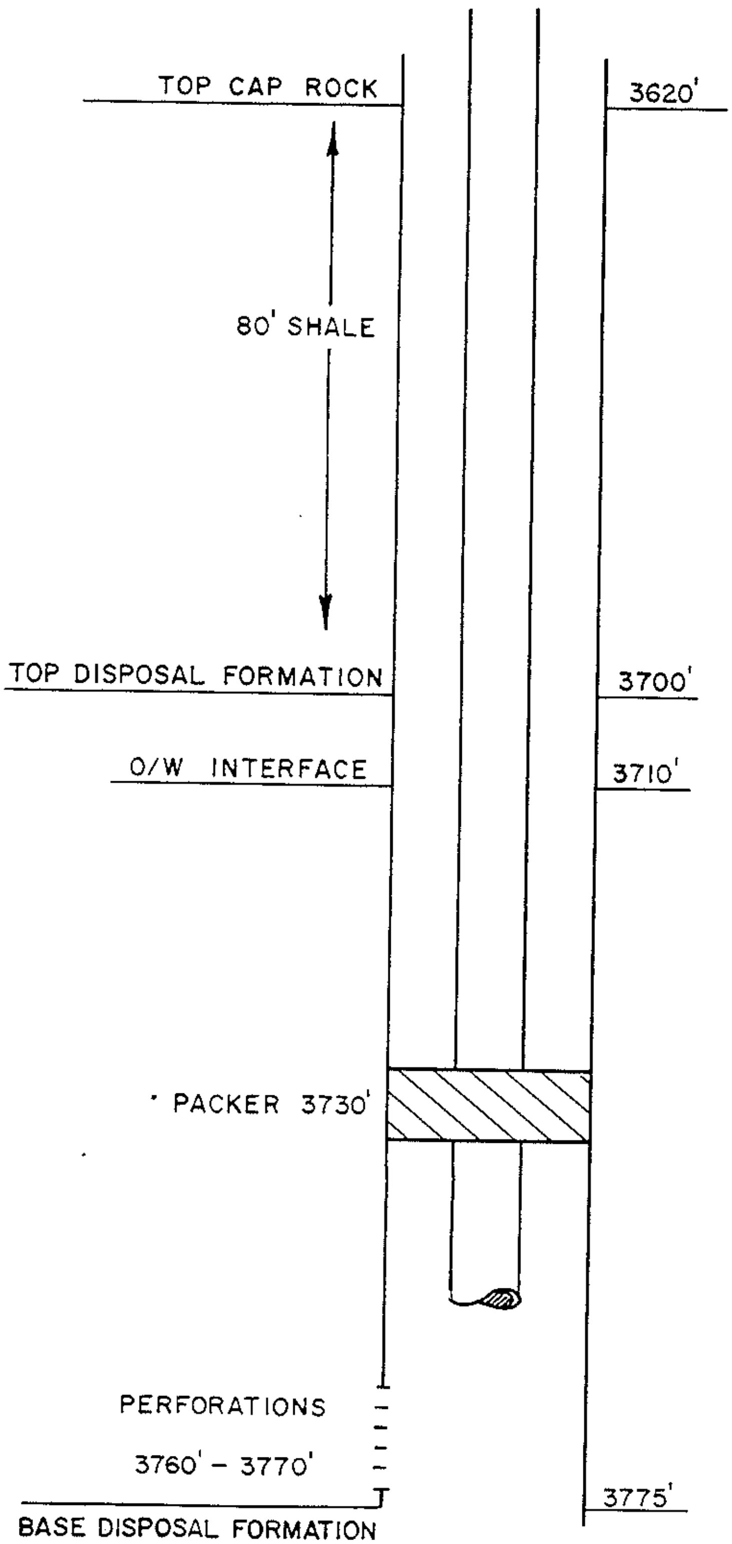
A.B. Oil Company Ltd.

Attachment

E.R.C.B. DISPOSAL WELL # 1

LSD. 1-20-20-20 W4

K.B. Elev. 2000'



RESERVOIR PARAMETERS

POROSITY	30 %
HORIZONTAL PERMEABILITY	100 MD
VERTICAL PERMEABILITY	10 md
INITIAL RESERVOIR PRESSURE	1000 psig
CURRENT RESERVOIR PRESSURE	600 psig

PRESSURES

SURFACE INJECTION	1000 psig Max.
BOTTOM HOLE INJECTION	1800 psig Max.
FRACTURE	2200 psig

THE BEHAVIOUR OF HYDRAULICALLY INDUCED FRACTURES IN OIL SANDS

by

Maurice B. Dusseault, B.Sc., Ph.D., P.Eng.
Associate Professor of Mineral Engineering
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Introduction

Conventional hydraulic fracture operations are usually performed in rocks of high tensile strength and at considerable depths in a single well or in several widely spaced injection points. Injection volumes are small compared to the reservoir volume. For most proposed *in situ* production schemes in Alberta's oil sands, massive hydraulically induced fractures are proposed. These fractures will be generated by injection of fluid volumes of a significant percentage of the reservoir volume (on the order of 2%), injection will take place in many closely spaced injection points, many pressurization cycles will probably take place, and large amounts of thermal energy will be introduced into the system. Furthermore, oil sands are cohesionless materials and the depths at which injection will take place are relatively shallow: from 200 metres to 600 metres. Behaviour of oil sand reservoirs cannot be explained by conventional fracture mechanics because of the gross system changes which occur as the result of these factors.

Characteristics of the Major Oil Sands Deposits

Two major oil sands deposits in which *in situ* pilot projects are being conducted at this time are the Athabasca and the Cold Lake deposits. Figure 1 shows the location of these two deposits along with the estimated bitumen in place, and Figure 2 shows the gross stratigraphy at each location with formations and major depositional environments indicated.

The McMurray Formation is a dense cohesionless quartzose sand deposited in an alluvial accretion plain (Mossop, 1978).

The deposit is characterized by much vertical and lateral variation in lithology which can have a considerable effect on the behaviour of horizontal fractures in this deposit. Table 1 lists some typical geomechanical and lithological characteristics of the Athabasca deposit. For greater detail of treatment the reader is referred to other publications (Carrigy, 1967; Dusseault, 1977; Dusseault and Morgenstern, 1978; Jardine,1974).

The Cold Lake deposit is the focus of the greatest *in situ* pilot project activity. Esso Resources Canada Ltd. is involved in the development of a major *in situ* oil sand scheme (Imperial Oil, 1978). There are two reasons for the Cold Lake deposit being a preferable location for the first attempts at large-scale *in situ* production; the reservoir is lithologically more uniform, and the bitumen in the interstices is at least one order of magnitude less viscous than that of the Athabasca deposit. The target reservoir in the Cold Lake deposit is in the Clearwater Formation. This formation is a fine-grained sand lithologically different from the McMurray Formation oil reservoir at the Athabasca deposit. The Clearwater sand is an arkose and contains appreciable quantities of feldspathic, lithic, and volcanic glass grains. Scanning electron micrographs of grains from the two deposits are shown in Figure 3 to demonstrate the textural difference arising from the difference in mineralogy.

Little research has been done on the geomechanical properties of the Cold Lake oil sands because of the extreme difficulty in obtaining samples worthy of detailed geomechanical investigation. What little is known of the geomechanical and lithological properties of the Cold Lake oil sands is summarized in Table 2.

Principal Stress Directions in the Oil Sands Deposits

In the Cold Lake oil sands deposit the minimum principal stress (σ_3) is horizontal and lies in the north-west south-east direction (Table 3). The total overburden stress (vertical principal stress) is equal to the total pressure of the overlying column of rocks and is approximately 10 MPa at a depth of 430 m. Pore pressures are on the order of 3.5 MPa. Controlled hydraulic fracture tests indicate that σ_3 is on the order of 0.71 to 0.91 of the overburden stress. It is not known whether the third principal stress direction, in the north-east south-west direction, is σ_1 or σ_2 as there is some evidence to support either assumption at different pilot project sites. Fractures in the Clearwater Formation reservoir in the Cold Lake deposit are initiated as vertical planes in a north-east south-west direction. Because of the depth of burial of the reservoir and the flat morphology of the ground surface, the stress conditions in the Cold Lake reservoir are expected to be uniform.

There is a considerable variation in the stress conditions in the Athabasca oil sands (Table 3). The depth of burial of the Athabasca oil sands ranges from 0 to 600 m. Loading and excavation processes in geological history have resulted in an increase in the ratio of horizontal-to-vertical stress throughout the region (Dusseault, 1977). There are a number of deep post-glacial valleys in the oil sands area; the Clearwater and Athabasca rivers east and west of Fort McMurray respectively occupy canyons as deep as 200 m. These valleys have important local effects on stress magnitude and orientation.

In relatively flat-lying terrain away from the major river valleys, it is expected that the direction of σ_3 will be vertical for depths shallower than 250 m but horizontal for depths in excess of 400 m. For the intermediate depth range, there is considerable uncertainty as to the direction of σ_3, and there is reason to believe that its value is not greatly different from that of the major principal stress. (In the shallower pilot projects such as the Texaco Canada project south-east of Fort McMurray, fractures are known to initiate in a horizontal direction). Further uncertainty as to the stress tensor orientation arises because of significant undulations of the limestone at the base of the oil sands (Carrigy, 1959).

Little is known of the behaviour of vertical fractures in the deeper sections of the Athabasca deposit, but is is known that horizontal fractures in the shallower portions of the deposit tend to climb upwards away from the fracture initiation point and tend to be confined by flat-lying cemented bands near the top of the formation (Figure 4) (Raisbeck, 1979). These "containing" strata are regionally discontinuous and cannot be relied on as guaranteed fracture deflectors.

Effects of Injection on Principal Stress Values and Direction

In those areas where fracture planes are originally vertical, massive injections over a short time are known to result in a change of fracture orientation. This phenomenon can be explained by a change in the minimum principal stress direction. Injection of massive volumes results in considerable straining in a direction normal to the fracture plane. This straining of the medium in a one-dimensional manner must result in an increase in the stress in that direction. After σ_H is equal to or slightly greater than the value of the original intermediate principal stress, it becomes more economical from an energy expenditure point of view for the fluid to reinject along a different direction (Figure 5).

If the injection rate is relatively rapid, then energy dissipation due to viscous traction on the walls of the fracture can result in thick fracture generation with rapid local overstressing, particularly near the injection point. It is believed that the minimum principal stress is increased to a value somewhat higher than the intermediate principal stress before reinjection takes place. Fractures therefore tend to recur by fluid injection in the direction approximately orthogonal to the original plane but still vertical if the direction of the intermediate principal stress was originally horizontal. If the direction of the intermediate principal stress originally was vertical, horizontal fractures are generated once the minimum principal stress is increased to a level equal to the overburden stress. The point of injection for these new horizontal fractures will be relatively high in the stratum to be consistent with viscous energy dissipation and because the overburden stress is the least at higher elevations, thereby allowing minimum energy expenditure.

In the case where the second fracture propagation direction is also vertical, stress build-up would continue due to the constraining effects of the surrounding earth and eventually horizontal fractures would be created. Evidence from several field operations confirm this conceptual model of fracture behaviour.

In those areas of the Athabasca oil sands deposit where the initial fracture propagation direction is approximately horizontal, the minimum principal stress direction is and remains vertical. If fluid is injected in massive volumes at high rates, a jacking-up of the surface of the earth takes place without significant increase in stress level. Fractures therefore will not change orientation dramatically during injection unless local stress fields are variable.

Numerical analyses of model vertical fractures in layered media with reasonable property assumptions confirm that regional stress changes can be brought about by massive injection volumes. There is reason to believe that, at the shallow depths of injection characteristic of oil sands projects, all fractures ultimately become horizontal as the result of stress changes. It must be noted that as these changes take place the values of the three principal stresses become more and more close to one another, eventually resulting in a near-hydrostatic stress state which will provide little preferred orientation control. If the major principal stresses are not greatly different, then minor lithologic variability dramatically affects fracture direction.

Lithologic Control on Fracture Propagation

Vertical fractures in the Clearwater Formation at Cold Lake tend to be confined in the reservoir (Figure 6). The clayey silts which bound the oil-bearing zone provide a barrier to the propagation of a fracture because of the higher energy required to traverse a material with cohesive strength. Pore pressure reduction in the material in advance of rapidly advancing fracture tip (because of dilatancy) may take place in the oil-free clayey silts. These materials are of sufficiently low permeability that a rapidly approaching fracture containing pressurized fluid may have no direct diffusion effect on the pore pressure, although an elastic dilatancy effect must occur because of the straining of the earth in advance of the fracture tip. If lower pore pressures arise from this dilatancy, they would tend to enhance the barrier effect of these clayey silts by increasing the resistance to shear and fracture.

If injection rates are high and injection is taking place at the base of the reservoir, breakthrough into the underlying McMurray Formation may occur. This can have disastrous consequences on process control as the McMurray Formation in this region is largely oil-free and is of high permeability and porosity. Breakthrough to formations above the reservoir is also undesirable because of the heat and fluid losses involved. It is not known whether the silty clays and clayey silts overlying the Clearwater strata form a long-term barrier to vertical fractures.

In those areas where horizontal fractures are initially created (these areas are to date known only in the Athabasca deposit), the fractures tend to climb upwards at angles of 10° to perhaps as high as 25° (Jenkins and Kirkpatrick, 1978; Settari and Raisbeck, 1978). The tendency for a horizontal fracture to climb has often been explained in terms of density; if air or gas is injected it is assumed that there is a tendency for fractures to climb upwards because of the buoyancy of the air or gas. Another explanation exists: in a material with variably oriented anisotropies (bedding planes, joints), fractures will tend to climb upwards along appropriately-oriented bedding features and other lithological discontinuities. There is a strong disinclination for fractures to propagate downwards because the greater stresses at depth require more energy expenditure and the process of fracture propagation is one of work minimization. If a highly cohesive stratum is encountered during the shallow climb of a horizontal fracture, the fracture will tend to skid along the interface between the two media. This accounts for the observation that horizontal fractures tend to follow the bottom of cemented or highly cohesive beds (Raisbeck, 1979). If the vertical principal stress (in this case the minor principal stress) is much less in either of the two other stresses, fractures tend to remain relatively flat lying. If the magnitude of the vertical principal stress is similar to either or both of the horizontal principal stresses, there is more tendency for the lithology to control the fracture propagation direction and cause a climbing of the fracture to a cohesive barrier bed.

In examining the relationships between stresses and lithology, careful assessment of local morphology may be valuable (nearby valley walls for instance) not just from the aspect of initial stress conditions but also from the aspect of stress change upon injection. Stress conditions may vary significantly with depth, but no rapid and reliable method exists for the accurate assessment of all of these stresses. Gross sample disturbance makes the value of detailed geomechanical laboratory investigation problematic, and a need exists for drilling and testing techniques to provide reliable *in situ* geomechanical data. This is important because after a hydrostatic stress condition has been approached, the effect of lithology on hydraulic fracture propagation direction is considerable. Detailed facies analysis and geomechanical behavioural tests of selected lithologies should aid in understanding how various factors affect fracture propagation direction.

Alteration of Oil Sand Properties as the Result of Injection

Massive volumes of injection of hot fluids at high velocities (at least near the injection point) probably results in erosion and remoulding of the cohesionless oil sands. The result of this is to enhance the porosity in the fractured zone. For example, the porosity of the Athabasca oil sands is expected to rise from an average value of about 30% to a value of approximately 36 to 40% upon remoulding. The effect of this remoulding upon the elastic properties of oil sands is great. For example, compressibility can be increased by an order of magnitude as the result of this remoulding. The relative permeability however is not so dramatically increased because the pores of the sand tend to become clogged rapidly with viscous bitumen once the well is put on production. The thickness of the altered zone of oil sand is not known, nor is it known if the altered zone forms a highly preferential fracture direction for subsequent fractures in the cohesionless oil sands. Quantification of these hypotheses remains to be systematically pursued by detailed field work, (Figure 7).

Conclusion

Conventional fracture mechanics derived for propagation in cohesive media are not applicable in oil sands because the sands are essentially cohesionless. Therefore, significant tensile stresses do not exist around the tip of a propagating fracture. A "fracture" in oil sands is essentially only a plane of parting. In those areas where vertical fractures are initially predicted, massive high rate injections will result in a change in stresses and fracture direction and ultimately the stresses will approach a hydrostatic state. This near-hydrostatic stress state will result in very little control of fracture propagation direction as the result of the principal stress differences. In this state, lithological differences will dominate. Predictive capabilities must be developed in these materials, and real-time monitoring of fracture growth (preferably by a surface method) should be utilized systematically in order to plan injection and production strategy in a more rational manner.

Assumption of material homogeneity is not justified for oil sands; the continental and deltaic nature of the formations in which the oil sands are found preclude widespread predictability, particularly in the case of the McMurray Formation at Athabasca. Ultimately, it is expected that surface methods of gaining access to oil sands (drilling) will be superseded by hybrid methods in which shafts with base working chambers are employed as sites for development by horizontal hole drilling. These methods will require hydraulic fracturing in any case, but the degree of control of hydraulic fracturing and consequently of the production process will be greater.

The most urgent needs in this area of oil sands engineering at present are a correct model of <u>in situ</u> behaviour, and useful geomechanical property data to use in analysis.

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Table 1

Athabasca Oil Sands (McMurray Formation) Properties

Mineralogy	:	quartz - 93% feldspar - 5% chert - 1% others - 1% (based on thin section analysis; mica and clay minerals probably average 2-3% overall)
Facies of Deposition	:	continental (stream) at the base grading upwards into accretion slope (alluvial) sands and tidal flat complex at the top.
Bulk Density (*in situ*)	:	2.11 ± 0.06 for coarse-grained sands and well-sorted fine-grained sands
	:	2.21 ± 0.06 for fine-grained sands
	:	2.32 ± 0.06 for sandyard clayey silts
Shear Strength	:	Very high for intact sandy material; 1.5-2.5 MPa for a normal stress of 1.0 MPa
Compressibility	:	$0.6 - 1.5 \times 10^{-6}$ kPa^{-1} in cyclic lab tests at 7.0 MPa
Dynamic Young's Modulus (geophysical)	:	4.0-8.0 GPa @ 70 m depth.

Table 2

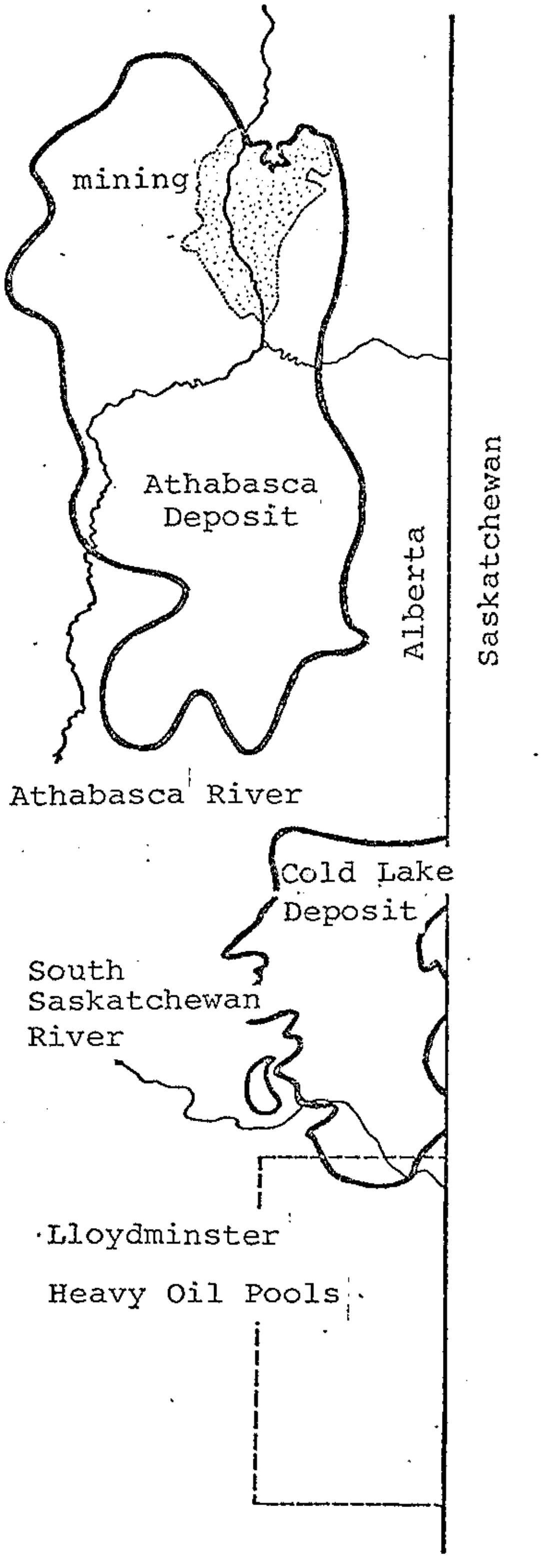
Cold Lake Oil Sands (Clearwater Formation Reservoir) Properties

Mineralogy	:	quartz 21% (based on this section analysis; mica and clay mineral probably average 2-5% overall; volcanics are highly siliceous) feldspar 28% volcanics 23% chert 20% argillite 3% metasediments 5%
Facies of Deposition	:	delta fringe (D_{50} = 95μ) to delta front and distributary channel (D_{50} = 165μ).
Bulk Density (*in situ*)	:	2.11-2.16 gm/cm^3 in sand facies 2.15-2.20 gm/cm^3 in silty facies 2.21-2.30 gm/cm^3 for overlying and underlying clayey silt beds
Shear Strength	:	no data available; may be low at high stresses because of clearable and incompetent grains.
Compressibility	:	no data; probably significantly greater than for Athabasca Oil Sands.
Dynamic Young's Modulus (geophysical)	:	4.0 GPa (assuming ν = 0.28) at 450 m depth.

Table 3

Known Fracture Orientations in Oil Sand

1. Peace River Deposit Bluesky-Gething Formation (550 m deep)	:	orientation not known probably vertical
2. Wabasca Deposit Grand Rapids Formation (250 m deep)	:	horizontal factures.
3. Cold Lake Deposit Clearwater Formation (370-450 m deep)	:	vertical fractures trending 30°-45° Az
4. Athabasca Deposit McMurray Formation	:	mining area: horizontal fractures (experiments to depth of 100 m)
	:	260 m overburden south of Fort McMurray: horizontal fractures
	:	350 m overburden south of Fort McMurray: uncertain
	:	Texaco site 20 km S.E. of Fort McMurray;100 m overburden relatively close to a valley wall: horizontal fractures (but breakthrough to surface has occurred).
5. Other Alberta Data	:	Medicine Hat gas field: 300-500 m overburden, horizontal fracture
	:	Pembina Oil Field: 1000 m overburden, vertical fractures @ N 45° W.



Athabasca Oilsands Deposit

Oil in Place: 138 (12 in stippled area)
($x\ 10^9\ m^3$)

Cold Lake Oilsands Deposit

Oil in Place: 31.2 Grand Rapids Fm.
($x\ 10^9\ m^3$) 6.4 Clearwater Fm.
5.4 McMurray Fm.

Three major reservoirs, two in the Grand Rapids Fmn, one in the Clearwater Formation

Depth of burial: 300-500 m

Lloydminster Heavy Oil Trend

Oil in Place: 5.6 x 10^9 m^3
(Alberta portion)

Depth of Burial: 650-800 m.

Numerous small oil pools

Figure 1: Major Oilsand and Heavy oil Deposits, Eastern Alberta

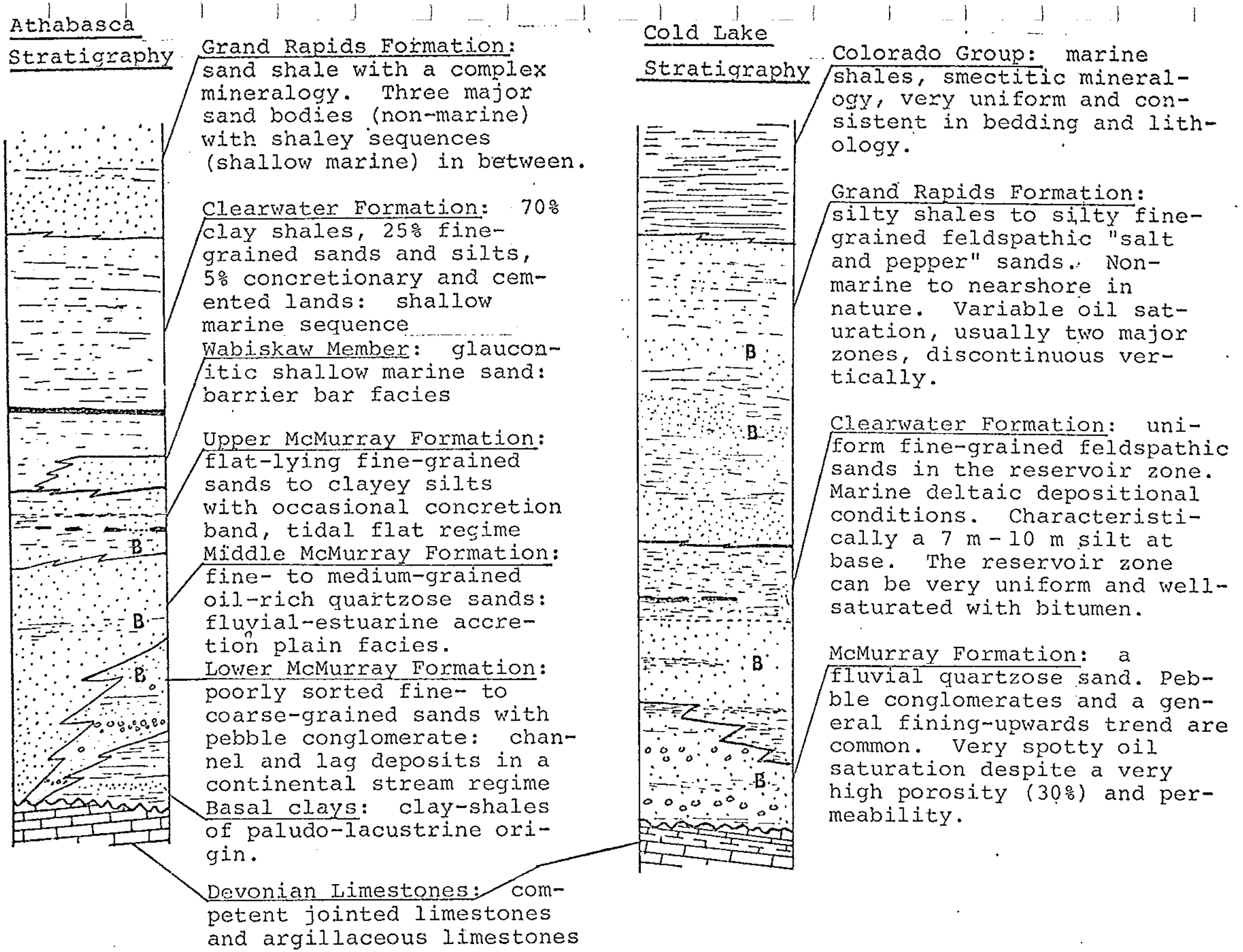
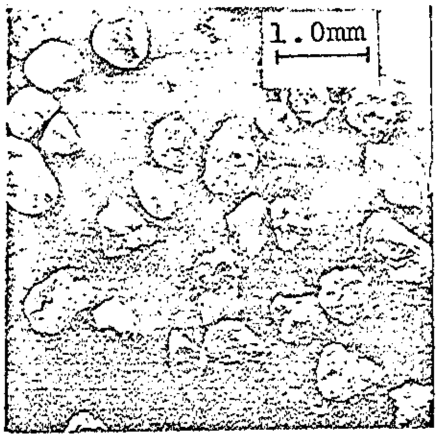
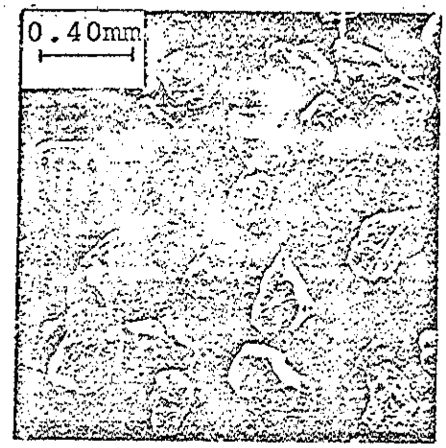


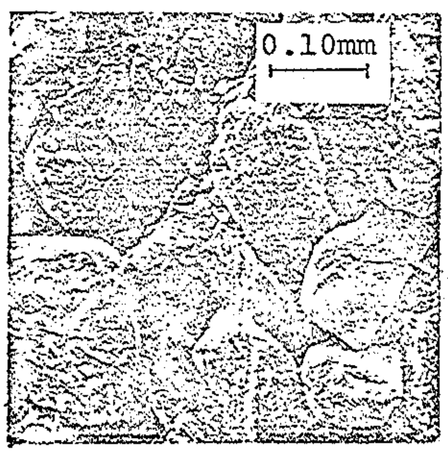
Figure 2: Stratigraphy and Depositional Environments of Alberta's Major Oil Sands



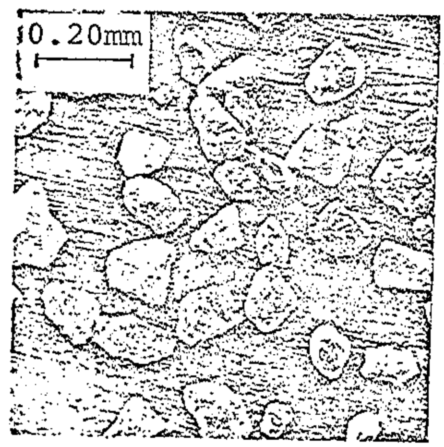
McMurray Fmn. grains
coarse-grained fraction



McMurray Fmn. grains
fine-grained fraction

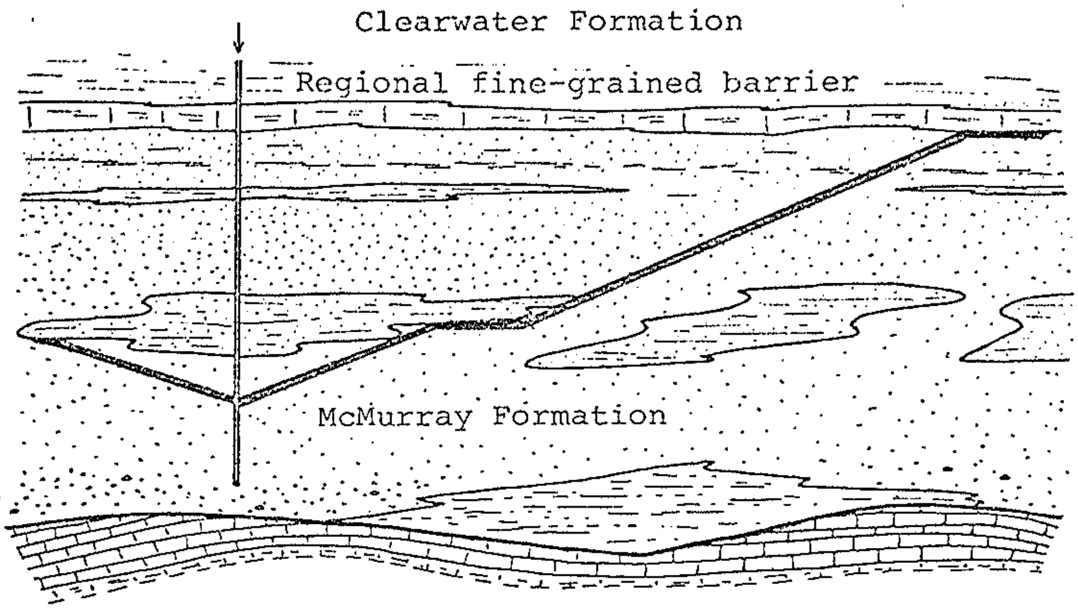


Clearwater Fmn. grains
undisturbed state

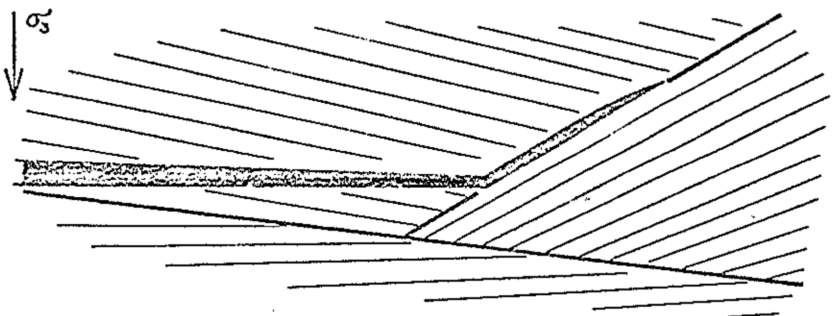


Clearwater Fmn. grains

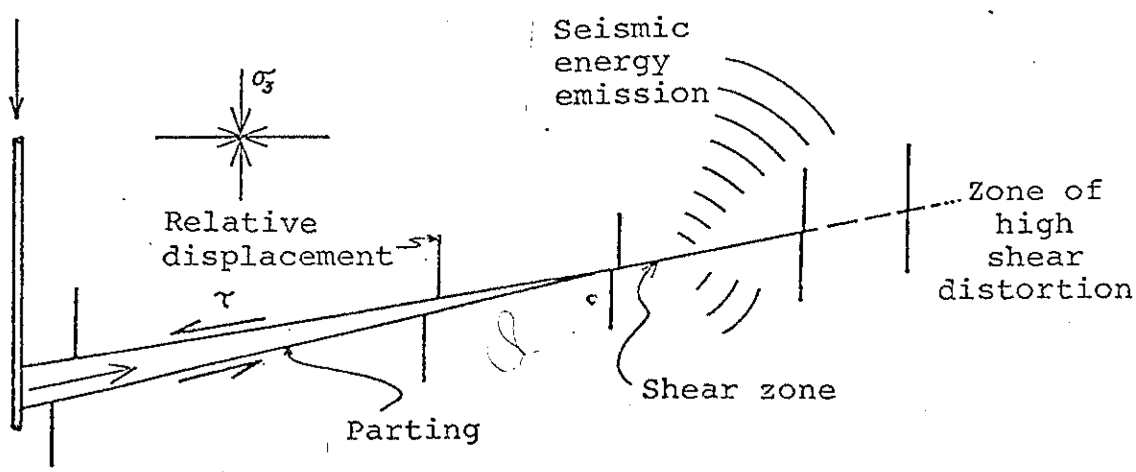
Figure 3: Grain Features, Oilsands Resevoirs



a) Horizontal Fractures Climbing in the McMurray Formation



b) Local Lithological Control on Fracture Climb



c) Relief of Shear Stress by Sudden Shear Failure

Figure 4: Behavior of "Horizontal" Fractures in Athabasca Oil Sand

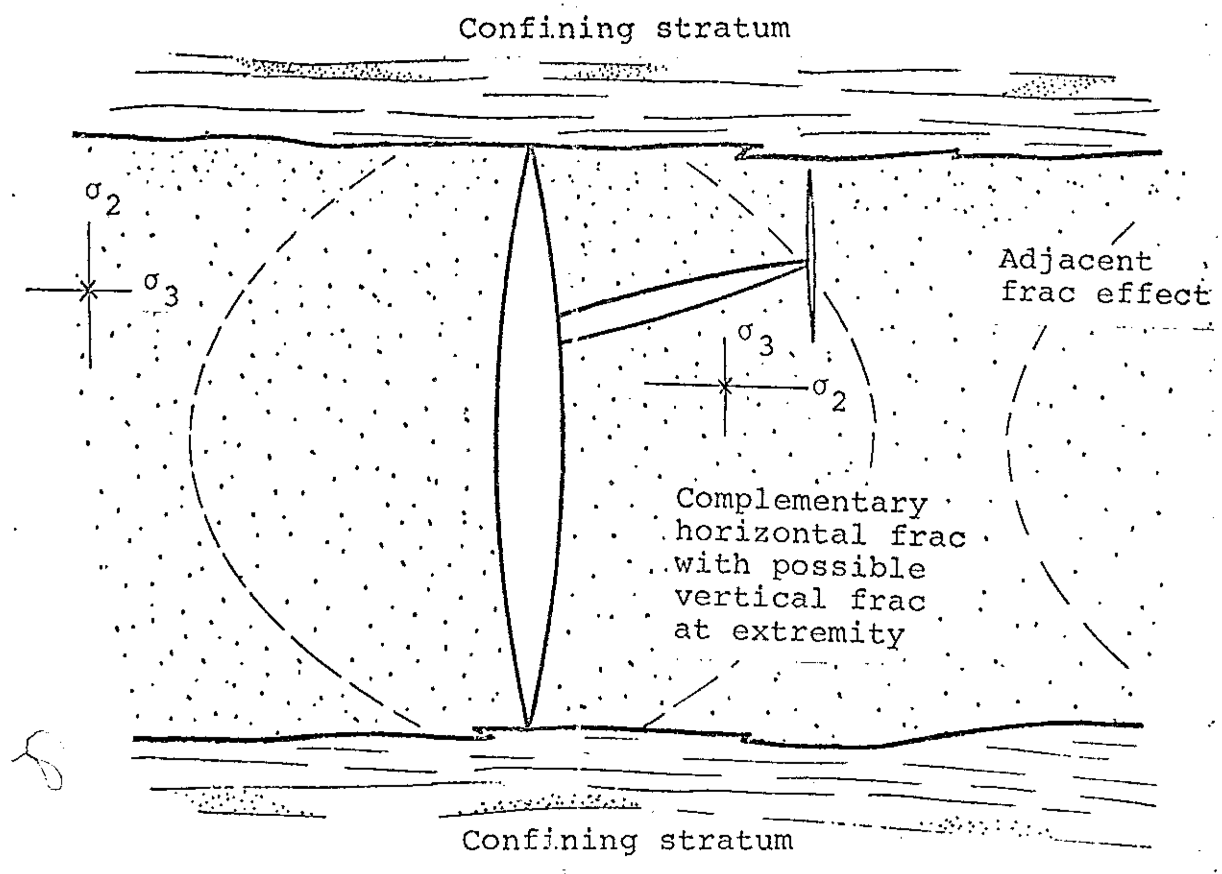
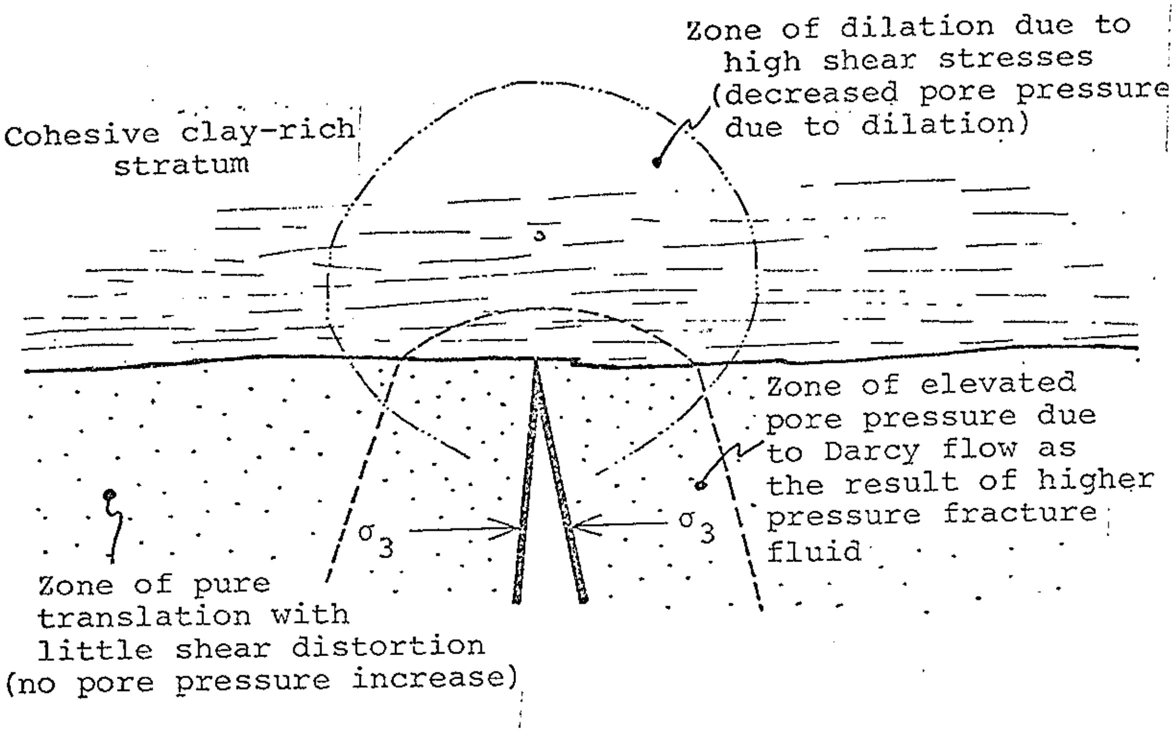


Figure 5: Change of Fracture Orientation Arising from Massive Injection



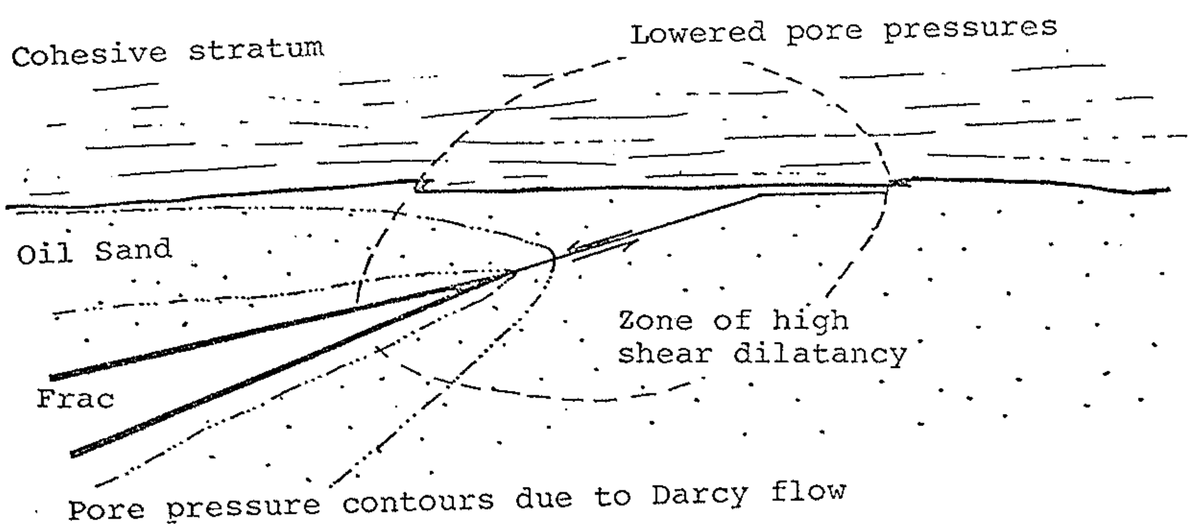


Figure 6: Pore Pressure Effects: Dilatancy,
Darcy Flow, Lithology

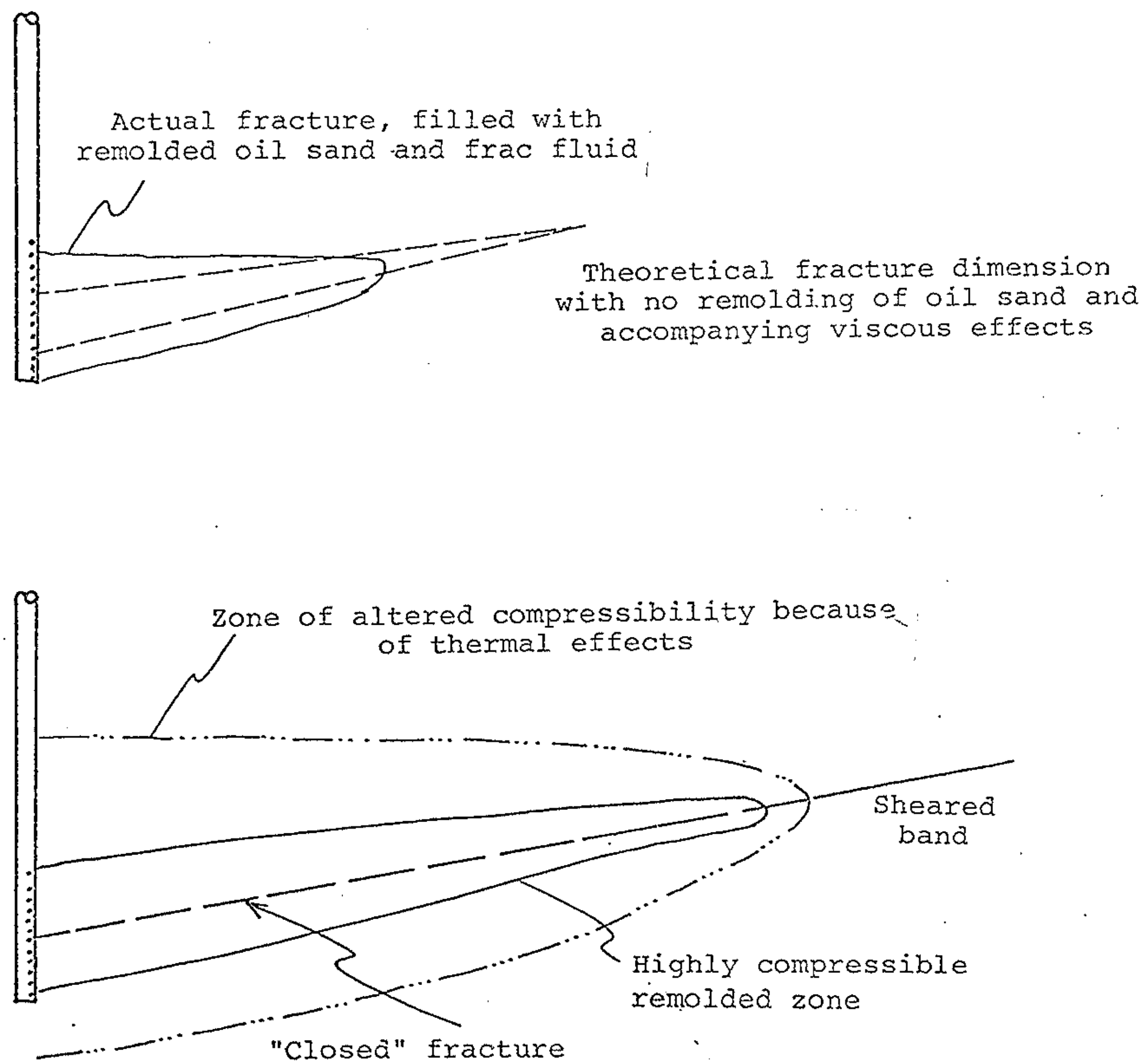


Figure 7: Alteration of Oil Sand Properties due to Injection

A CONCEPTUAL GEOMECHANICAL MODEL FOR HYDRAULIC FRACTURE IN THE ATHABASCA OIL SANDS

by

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ABSTRACT

A conceptual geomechanical model of earth behavior during massive hydraulic fracture in the Athabasca Oil Sands area is presented. Traditional fracture models use brittle tensile failure criteria for crack propagation. Oil sands are cohesionless, dense granular materials of very low permeability. Their behavior when subjected to massive and repeated injections of hot liquids cannot be assessed by traditional models.

Injections will result in changes of the stress field towards a hydrostatic state; this, in turn, means that an initially well-defined preferential fracture orientation will become changed as the result of injection. When a hydrostatic stress field is approached, lithological variability becomes an important parameter. Because horizontal fractures tend to propagate upwards at shallow angles, shear failure in advance of a propagating parting plane must occur to relieve accumulated shear strains. These shear failures will probably be of the stick-slip type and detectable by seismic techniques. Serious impairment of well integrity can occur because of shear displacements.

Massive injections of high temperature liquid remolds oil sand and creates zones of high porosity and low "elastic" modulus. However, the high stresses and viscous bitumen result in a "self-healing" of fractures with important results on thermal energy recovery and fluid flow.

Extensive analytic predictive capability is presently not within reach, and development of observational techniques is necessary to provide a process control capability. Numerical and laboratory modeling should aid these efforts.

INTRODUCTION

There is a need for a unifying conceptual model to explain observed behavior of the Athabasca Oil Sands during hydraulic fracturing operations and to serve as a predictive tool for future larger scale operations. Most conventional hydraulic fracture operations to date have been characterized by relatively small injection volumes compared to the volume of the reservoir, and have been carried out at considerable depth in single-point or several-point widely-spaced injections in cohesive rocks. By contrast, *in situ* production schemes in Alberta oil sands deposits which require hydraulically induced fractures to create and enhance permeability will use massive injection volumes and will take place at depths no greater than 600 m in multi-well, closely-spaced injection points, and will be generating fractures in a cohesionless granular medium. Unusual behavior has been observed in a number of pilot projects; a geomechanical model is presented herein to explain this behavior. The model leads to some startling predictions of earth behavior.

THE GEOTECHNICAL CHARACTERISTICS OF THE ATHABASCA OIL SANDS

For several reasons, the model has been developed for the Athabasca deposit only: the geomechanical characteristics of the Athabasca Oil Sands have been the object of considerable research; little information exists in the public domain for other oil sand deposits; and lithologic and other differences between deposits indicate that one behavioral model may not be adequate to describe all deposits. This limitation is also a strong argument for the collection and public dissemination of fundamental geomechanical data on oil sands to aid basic research upon which technological advances will depend.

Within the Athabasca deposit itself there is considerable variation in lithology, bulk density, bedding features, and other properties. Most injection operations will take place in oil-rich sands near the base of the McMurray Formation. The ranges of geotechnical properties listed in Table 1 and illustrated in Figures 1 to 3 are considered representative of these materials. The major features of oil sand behavior are strain-weakening, small strains to failure, dilatancy considerably greater than ordinary dense sands, relatively high strengths, curvilinear failure criteria, absence of cohesion at zero stress, and stress-stiffening behavior (Young's Modulus is greater at larger values of confining stress). All of these characteristics are observed under conditions of shearing to failure under a confining stress.

In addition to these characteristics of the intact material, when oil sand has failed or has been remolded, during shear it behaves as a normal granular material with a friction angle of appropriately 30 to 35 degrees. These data may be supplemented by reference to a number of works of a geotechnical nature (Hardy and Hemstock, 1963; Carrigy, 1967; Brooker, 1975; Dusseault, 1977a, 1977b, 1979a, 1979b; Dusseault and Morgenstern, 1978a, 1978b, 1979; Dusseault and Root, 1979; Dusseault and Scafe, 1979). No laboratory data on behavior during injection has been published.

BEDDING FEATURES AND DISCONTINUITIES IN OIL SAND

Bedding features and discontinuities (either physical or lithological) can have an important secondary effect on the propagation direction of an hydraulic fracture. Accordingly, a brief discussion of the most important of these is warranted. Many publications discuss the geology and stratigraphy of the Athabasca oil sands in general (Carrigy, 1959, 1963, 1966; Jardine, 1974; Martin and Jamin, 1963; Mossop, 1978); however, detailed stratigraphic and lithological data must be gathered on a site specific basis because of the considerable local and regional variability of the McMurray Formation (Stewart and MacCallum, 1978). The most important bedding structures in the lower part of the McMurray Formation are cross-bedded units having individual beds dipping at angles of up to 35 degrees, with the units themselves having dips of a few degrees.

Jointing surveys have been conducted on many river outcrops in the Fort McMurray area (Babcock, 1975). One conclusion from Babcock's paper is that there are regional trends to jointing, and the preferred directions in the McMurray Formation are approximately northeast and northwest (orthogonal). These joint surveys were, of necessity, performed only on indurated beds within the McMurray strata. The great majority of the oil-rich medium- to fine-grained sands in the lower and middle part of the McMurray Formation do not display diagenetic jointing patterns in outcrop. They do, however, display stress-relief jointing subparallel to the surface of the outcrops. Because these materials do not display significant jointing at surface they cannot be expected to have detectable jointing at depths of burial of greater than 100 meters. Babcock's conclusion (1975) that "...regional joints in the oil sands will probably act as conduits for fluid migration during the fluid injection phase of in situ heavy oil recovery" is not held by this writer for the conditions of hydraulic fracture flow. For production flow or injection pressures below fracture pressure, this conclusion may be valid to some degree. Joints are probably closed and clogged at depth, and fluid flow at the hydraulic fracture pressure required for injection is controlled by stress fields, rather than jointing patterns.

FIRST-ORDER CONTROLS ON HYDRAULIC FRACTURE PROPAGATION DIRECTION

The two major geometric characteristics of fractures are 1) the fracture plane orientation and 2) the direction in which the fracture propagates upon injection of a new increment of fluid (air or water).

The orientation of a fracture is a function of the stress field in the ground (Hubbert and Willis, 1957). Given three orthogonal principal stresses, a fracture will open (Mode I fracture) against the direction of the least of these stresses (Figure 4). That is, the vector normal to the fracture will correspond closely to that of the minor principal stress. It should be carefully noted that the direction of the minor principal total stress is exactly the same as the direction of the minor principal effective stress, because the pore pressure is a hydrostatic tensor. Because hydraulic fracture direction is controlled by the stress field, carefully controlled fracturing is used to determine _in situ_ stresses (Zoback and Pollard, 1978).

The orientation of hydraulic fractures will correspond to that plane where a maximum surface area can be created by a minimum of work; the fracture will grow in the appropriate direction to minimize work performed during fracture growth. The dominant orientation of fractures in a significantly anisotropic stress field in the earth can only be altered by changing the orientation of the principal stresses: if horizontal fractures are desired in a region of the earth where vertical fractures are known to propagate, the only way to assure generating horizontal fractures is to change the state of stress within the whole zone of fracturing so that the minor principal stress is vertical. As will be discussed later, this may not be as difficult a task as has been previously assumed.

The direction in which an hydraulic fracture propagates is also a function of work minimization. Therefore, in a near-hydrostatic stress field and an isotropic medium, a propagating fracture will tend to climb; this is true for both horizontal and vertical fractures, and is a result of lesser values of minimum principal stress higher in the earth. It can therefore be assumed that if a fracture injection point is at the base of the McMurray Formation, vertical fractures generated would tend to rise through the formation (Figure 5) because the lithostatic stress field is not grossly anisotropic. This climbing tendency has been observed in natural magmatic fractures (Pollard, 1978). On the other hand, if a horizontal fracture is generated at the base of the McMurray Formation and that fracture encounters any geologic discontinuities such as bedding features which dip upwards relative to the fracture propagation direction, the fracture will likely follow that discontinuity providing that it minimizes work expenditure; the fracture in general would not follow a downward dipping feature because work expenditure would be greater in that direction. Horizontal fractures therefore tend to climb towards a zone of lesser stress. This is confirmed by direct field observation of heating patterns (Jenkins and Kirkpatrick, 1978).

These statements are correct for injection of low-viscosity fluids at reasonable rates of injection. Because of the viscous drag energy losses which may occur during high-viscosity high-injection-rate hydraulic fracture, local pressures in the fracturing fluid are not equal but drop as fracture width decreases and as distance from the injection point increases. These phenomena depend on fracture size and will result in unknown values of fracture tip pressures, and fracture growth and propagation cannot be accurately predicted without more detailed knowledge of dissipation and distribution of pressures (Zoback and Pollard, 1978).

The orientation of major principal stresses is not uniform throughout the Fort McMurray area. Dusseault (1977b) suggests that, as a result of sedimentary or glacial loading and subsequent unloading, the minor principal stress is vertical near the surface of the earth down to a depth of perhaps 300 meters (Figure 6). Below that depth, there is a 150 meter zone in which the minimum principal stress direction is basically unknown, and below 450 meters, the minimum principal stress direction is horizontal and is probably oriented between Az 300° and 330°. These numbers should be treated with a great deal of caution as topographic variability within the area of the Athabasca Oil Sands is very great: over 400 meters from valley bottom to height of land. In addition, significant alteration of stress field may have taken place near river valleys which have been incised deeply into the surrounding highland; for example, the canyon of the Athabasca River west of Fort McMurray and the valley of the Clearwater River east of Fort McMurray are more than 200 meters deep. Finally, differential compaction because of an undulating paleotopography (Carrigy, 1959) may have resulted in significant local changes in principal stress directions during burial, and this variability may exist to the present day.

There is another uncertainty with respect to hydraulic fracture orientation in oil sands. If either one or two of the other principal stresses are very similar in magnitude to the value of the minor principal stress, then lithologic variability, bedding structures, or small variations in stress direction will have a significant effect on fracture orientation and fracture propagation direction. It is quite probable that if a vertical fracture were initially generated and propagated upwards, it could become horizontal or at least begin curving over in that zone where minor principal stress direction changes over to vertical. This latter hypothesis may have important environmental consequences as vertical fractures would not be expected to break directly upwards to the surface because of high lateral stresses near the surface. In the zone from 200 m to 500 m burial in the Athabasca Oil Sands area, the stress fields are probably sufficiently close to hydrostatic (K_o = 0.9 - 1.1) that detailed lithological investigations may be distinct aids in predicting fracture behavior.

MECHANICS OF HYDRAULIC FRACTURE IN OIL SAND

Although oil sands are dense, the individual grains are not cemented together in any way; oil sands are essentially cohesionless at zero stress. Because there is no tensile strength, oil sands do not fracture (in the traditional sense of that word). Rather, the material separates or parts (Mode I "fracture") along planes normal to the minor principal stress. Virtually no energy is expended in creating a physical discontinuity in a material of no significant tensile strength or cohesion. There is some amount of interpenetrative fabric (Figure 7), and overcoming this interpenetration may result in a small energy expenditure, but the amount would be negligible with respect to the work done in overcoming the lithostatic stress field. This fact explains the unusual nature of pressure-time data from hydraulic fracture operations and from breakdown pressure measurements (Figure 8). If injection is carried out carefully and slowly, the formation breakdown pressure in oil sands will be very similar to the propagation pressure which in turn should be very similar to the instantaneous shut-in pressure. These observations are borne out by the pressure-time curves of hydraulic fracture operations at several locations within Alberta's oil sands (Settari and Raisbeck, 1978). Because no energy is spent in overcoming tensile strength, the parting pressure, propagation pressure, and instantaneous shut-in pressure are approximately equal, and the magnitude of these pressures is about the value of the minimum principal total stress.

Because the oil sands do not "fracture", stress fields at the tip of a propagating parting plane bear little relation to those predicted by traditional fracture mechanics derived for cohesive materials. However, there can be a significant shear stress concentration at the propagating fracture tip. If a fracture is propagating in the precise direction of one of the principal stresses (Figure 9), no shear stresses across the fracture plane exist. However, as a result of minor variabilities and a tendency to climb, fractures will deviate somewhat from a precise orientation with the principal stress, therefore significant shear stresses across the fracture plane must be relieved. Shear stresses are relieved through the shear strains expressed as lateral displacements across a fracture plane. The shear strains are accompanied by changing stress fields near and in advance of the tip and sides of a growing parting plane. The shear stress concentrations at the edges of the parting plane have to be relieved in advance of the plane by shear failure (Mode II and Mode III fracture) in a band extending away from, but in the same orientation as, the fracture (Lockner and Byerlee, 1977).

The extension of an inclined parting plane by fluid injection leads to shear fracture by direct shear (Mode II fracture) or by transverse movement (wrench fracture or Mode III fracture). In the most simple case where the two horizontal stresses are approximately equal, the lateral edges of an inclined fracture are sites of considerable shear stress concentrations and probable Mode III failure. The magnitude of the shear stresses, as compared to those at the frontal edge where Mode II fractures are most probable, is highly dependent on the elastic properties of the medium and the planar shape of the fracture. Mode III fractures are similar to Mode II fractures (direct shear or thrust) in that the shear strength of the oil sand must be overcome and failure is therefore directly dependent on effective stress distribution around the fracture. Because of the similarities between the two shear modes, this discussion will concern itself with Mode II while recognizing that if Mode II is occurring, then Mode III almost certainly takes place.

These conceptual discussions have important implications for hydraulic fracture operations in oil sands. Significant displacements can take place far in advance of a fracture, and because of the extremely viscous nature of the bitumen in the oil sands, detection wells measuring only fluid pressure and temperature may not record anomalous behavior despite the fact that significant strains or displacements are taking place in the vicinity.

Several very important controls on shear behavior of oil sands must be mentioned.

1. Fully non-penetrating fracture fluid behavior is only possible using extremely viscous fluids or high injection rates; in fact, when fractures are quite extensive, penetration effects increase the pore pressure in advance of the fracture, thereby decreasing the effective stresses and the consequent failure shear stresses, rendering shear failure more probable.
2. Hydraulic (or pneumatic) fracturing in general increases deviatoric stresses ($\sigma_1 - \sigma_3$, cyclic), thereby resulting in dilation which can affect pore fluid pressures.
3. Gas in solution in oil sands will tend to keep pore pressures high (Dusseault, 1979a).
4. Pore fluid response to a stress-field change will occur on a different time scale as compared to the response to a boundary fluid pressure increase. A stress change can occur throughout an elastic mass upon distortion whereas a simple boundary fluid pressure change must diffuse through the mass in a manner analagous to consolidation.

Displacements are not merely interesting phenomena; because the oil sand is strong and rigid, if these displacements are large they can bend and ultimately rupture production casing that traverses the zone of shear failure. Furthermore, these zones of failure exist in advance of the actual fracture plane in all directions; therefore a strategy of careful well placement may not guarantee well integrity. Because shear failure is preceded by shear distortion, one method of measuring the development of these shear bands would be to make extremely accurate measurements of the vertical distortion of a borehole which is physically coupled in a compliant manner to the surrounding oil sand (as opposed to using a "rigid" casing string). Other methods, for example strain gages pre-installed on casing, may be used. Careful instrumentation is required as shear distortion may be small as the result of the stiff, brittle nature of Athabasca oil sands (at least at lower stresses).

Monitoring of pressure changes around an area in which hydraulic fracture is taking place may yield data which is difficult to interpret. Shear distortion in a dense quartzose material such as oil sands is accompanied by general dilation of the fabric of the oil sand. This dilation (volume increase) may result in decreasing pore pressures because of the very high impedance of oil sand due to the viscous bitumen. However, shear failure itself is confined to an extremely narrow plane and once failure is complete, dilation may become negative. It may be concluded that if pressure monitoring devices indicate decreasing pressures, shear distortion is the dominant local phenomenon; on the other hand, if pressures increase significantly, actual communication with the injecting fluid is probably taking place. Because of the presence of pressure-dissolved gases, the consequences of shear-induced dilation on pore fluid pressures in oil sand are complex: as dilation tends to reduce pore pressures, pore gas maintains them due to expansion and exsolution (Dusseault, 1979a, 1979b).

Changes in effective stresses ($\sigma - u$) within the oil sand itself must be taking place during hydraulic fracture operations. The rate of change of pore pressures is a function of the relative permeability and the compressibility of the oil sands, and neither of these have yet been measured with sufficient accuracy to predict pore pressure propagation rates. Low compliance in situ pressure transducers may be required to measure these phenomena. Careful assessment of pressure coupling to injection strategy is necessary as an aid to interpretation of data.

ALTERATION OF STRESS FIELDS AS A RESULT OF MASSIVE HYDRAULIC FRACTURE OPERATIONS

In those areas of the Athabasca Oil Sands where hydraulic fracture orientation is approximately horizontal, no significant changes in horizontal fracture orientation can take place because the minor principal stress is vertical and all of the displacement takes place in that direction against a stress free boundary; the surface of the earth. Any strains that are imposed upon the ground are much greater in the vertical direction and these strains, caused by thermal expansion and by injection of fluid volumes, are taken up by an increase in elevation of the ground surface; a vertical displacement.

In those areas of the Athabasca Oil Sands where fractures have a tendency to propagate in a vertical orientation, there is no free face parallel to the fracture orientation, and therefore strains cannot be relieved by a direct movement. This leaves two alternatives for the release of strain: either the stress in the direction normal to the fracture must increase, or the strain must be rotated and translated such that vertical ground displacements are ultimately created at some distance from the fracture. Although the latter in fact does take place, there is excellent evidence to show that stresses increase as a result of fluid injection, and probably also as the result of the addition of significant quantities of heat. Very little research information exists on pressure/time relationships for long periods of time and large volumes of injection in oil sands. What little information does exist shows that, as time and injection volume increase, pressures rise significantly (Settari and Raisbeck, 1978). Their Figure 10 shows that the initial pressures for this injection experiment were on the order of 8 MPa. As injection proceeded, the pressure increased to approximately 10 MPa at the fifteenth day of injection. Although there is some obvious correspondence between injection rate and well head pressure in their diagram, careful examination of the data suggests that rates and pressures are not totally coupled, and that the effect could be related to local well bore stresses. A logical explanation of the increasing pressure is that increase of the minor principal stress is taking place because of injection of fluid in planes normal to that stress, and because of the input of thermal energy which causes one-dimensional thermal expansion in the same direction as the minor principal stress. Similar trends have been observed on other field experiments (Imperial Oil Limited, 1978). The value of 10 MPa corresponds approximately to the pressure of the overburden materials in the area where this experiment took place. The value of 8 MPa for an initial pressure, when divided by the overburden pressure of 10 MPa, yields a stress ratio of 0.8, which is extremely reasonable based on the model for lithostatic stresses presented by Dusseault (1977b).

A major and rather startling conclusion must be drawn from these data. In the shallow reservoirs of the oil sands where there are no dramatic anisotropic rock properties, vertical fractures will be generated only for limited fracture operations. If projects require massive volumes of injection over long periods of time at a large number of closely spaced injection wells, then horizontal fractures <u>must</u> ultimately be generated. This has serious implications as some <u>in situ</u> production methods require vertical and non-communicative fractures in order to be successful. This conclusion has not been counter-indicated by any published data to date and offers a more rational explanation for some of the unusual behavior shown during oil sands fracture operations.

REMOLDING OF OIL SANDS AND HEALING OF FRACTURES

The oil sands, essentially granular cohesionless materials, do not truly fracture, and if the fluid filling a fracture is removed or dissipated, the stresses in the earth would tend to return the material to approximately the initial configuration. If there has been no general remolding, there may exist a zone in which porosity is enhanced, but no true discontinuity is created that did not exist before hydraulic fracture operations; that is, no tensile "failure" is possible in a cohesionless medium. However, remolding of the material as the result of significant fluid velocities and high temperatures of injection fluid is extremely likely. After the effective stress has been relieved on the surfaces of a fracture, the oil sands are held together only by extremely small amounts of cohesion due to intergranular penetration, and by the viscous bitumen. High temperatures reduce the viscosity of the bitumen, and high velocities of fluid injection (viscous drag) can overcome the small amount of fabric cohesion present in the oil sands at low stresses. It is extremely probable that, as a consequence of any significant fracture operation, a dramatic remolding of oil sands takes place, particularly in the vicinity of the injection borehole. This remolding may not be obvious or even detectable in cores taken through a fracture zone as coring operations themselves result in significant damage to oil sands as a result of exsolution of pressure dissolved gases (Dusseault, 1979c), and because the black and viscous bitumen-containing oil sands are difficult to differentiate visually. Furthermore, the porosity differences may not in fact be large. In situ porosities are about 30% for Athabasca Oil Sands; the porosity of a disaggregated sand which is redensified as a consequence of the imposition of effective stresses on the order of 5-7 MPa may be as low as

32-36%. Since any porosity difference may be in a limited band, the detection of this difference by geophysical methods which average porosity over a significant vertical extent is problematic.

If large quantities of oil sand are actually "eroded" and carried along with the hydraulic fracturing fluid, this results in a change in properties of the fluid and changes in the behavior of the formation during fracturing which are extremely difficult to assess. Dramatic remolding of the oil sands may be a positive factor when attempting to maintain the integrity of casing production strings and monitoring wells. If oil sands are remolded, the strength and moduli are significantly decreased, and the oil sands will have a tendency to deform in a plastic manner upon the imposition of shear stresses rather than to shear in a more or less brittle manner.

RE-INJECTION AND FRACTURE WIDENING IN OIL SAND

Viscous energy expenditure along fracture planes results in an increased fluid pressure near the borehole during injection resulting in fracture widening (Coulter, 1976). Because of the cohesionless nature of oil sands, fracture widening by reinjection close to the bore hole must be very carefully evaluated when considering fracturing behavior. As oil sands have no tensile strength, when a fracture has been created it may be a preferred direction for subsequent or continued fracture, but not greatly so as in the case of a material with a high tensile strength. As a consequence, as hydraulic fractures propagate outward, it soon becomes more economical from a work standpoint for the fluid to reinject along a new fracture closer to the borehole, or to widen the existing fracture, than to lose energy through viscous dissipation by flowing down long fractures. This means that a fracture may not be a single plane of parting on the order of several centimeters thick and many square meters in area, but could consist of a number of planes of parting, perhaps directly or approximately in contact, and more or less parallel providing the lithostatic principal stress directions have not been altered. The use of extremely viscous fluids and higher rates of injection would probably dramatically increase the incidence of rein-jection and fracturing widening, whereas extremely slow injection rates using non-viscous cold fluids would probably result in greater lateral extent of fracture planes. More so than in cohesive materials, the width and lateral extent (but not orientation) of fractures in oil sands may be significantly affected by controlling viscosities and injection rates.

LITHOLOGIC CONTROLS ON HYDRAULIC FRACTURE ORIENTATION AND PROPAGATION

Lithology can have a significant effect on overall fracture orientation. Figure 10 shows how beds with significant cohesion (tensile strength) can affect significantly the orientation of a fracture. Vertical fractures tend to propagate upward until they encounter a bed in which the cohesion is sufficiently high to form an energy barrier to vertical fracture propagation, causing the fracture to propagate laterally rather than traversing a zone of appreciable cohesion (Fast *et al.*, 1977). Since lithologic changes are at least an order of magnitude more closely spaced in the vertical direction than in the horizontal direction, no impedance to horizontal propagation of a vertical fracture can be suggested within reservoirs such as the Athabasca Oil Sands deposit or the Cold Lake Oil Sands deposit. As previously stated, a horizontal fracture has a tendency to climb in a material which displays an appropriately aligned anisotropy of strength as the result of minor bedding features and lithologic variability. If a stratum of high cohesion is encountered during the shallow climb of a horizontal fracture, the fracture tends to skid along the interface between the two media. If the overlying cohesive material (e.g. lenses of clay shale) is laterally discontinuous, then fractures would tend to continue their shallow horizontal climb once the influence of the zone of high cohesion was beyond the tip of the propagating fracture. These generalizations must be carefully assessed within the framework of the previously presented portion of the geomechanical model which predicts the existence of shear bands in advance of the tip of the hydraulic parting plane.

Data for Athabasca Oil Sands fracture operations generally confirm these observations; hydraulic fractures tend to climb, and vertical fractures do not propagate upward into the Clearwater Formation. In the upper portion of the McMurray Formation and the lower Clearwater Formation, ironstone bands are relatively common. Although these ironstone bands are discontinuous locally, they may have some effect on the propagation of horizontal fractures. They should not, however, affect the propagation direction of vertical fractures in the same manner, as a vertical fracture can traverse the discontinuities with greater ease.

CONSEQUENCES OF THE BRITTLE STRENGTH BEHAVIOR OF OIL SAND

Oil sand displays a stress-strain curve which has a significant peak strength. This peak strength has two important consequences on hydraulic fracture propagation. First, because of the concentration of shear stresses in advance of a hydraulic fracture, shear resistance can be overcome in an instantaneous manner, a shear band is extended suddenly, becomes temporarily locked, and the hydraulic fracture grows at a different location for a period of time. This stick-slip behavior is observed in natural faulting in most earth materials at shallow depths where dilatancy is not overcome by confining stresses. The segmental and cusp-like features observed in natural sheet intrusions (Pollard, 1978) may be a reflection of a stick-slip mechanism during injection. Secondly, this stick-slip behavior should create small seismic events in the earth, even if shear displacements are small (Brown and Butler, 1977). These seismic events should be of a sufficient magnitude (Richter magnitude of -1 to 1) to accurately map from the surface and from borehole detectors. If borehole detectors are used, the acoustic velocity of the oil sand will probably be consistent enough over large areas that these seismic events can be deconvolved accurately and positioned quite precisely in space. It would seem that this is a promising approach in the monitoring of the spatial propagation of hydraulic fractures in oil sand. At such shallow depths, and in materials of a granular nature such as oil sands, the magnitudes of these seismic events will be quite small, and excellent microseism techniques will probably have to be employed to accurately map fracture propagation. In contrast to most seismic monitoring arrays, an array to map oil sand fracture behavior must be of the real-time type; that is, it may be important to understand where the fracture is growing at a given time during an injection operation; therefore time/event data will have to be monitored and deconvolved continuously.

CONTROL OF HYDRAULIC FRACTURE ORIENTATION AND PROPAGATION DIRECTION

As has been shown, it may ultimately be impossible to control hydraulic fracture orientation; all shallow massive hydraulic fracture operations will eventually create different fracture propagation directions. This is not necessarily detrimental as horizontal fractures are the most desirable type of fracture to create interwell communication in several proposed *in situ* technologies. Because failure takes place in advance of the injection fluid and in advance of any dramatic increases in pore pressure, the pore pressure may perhaps be manipulated in order to control fracture propagation direction. This would involve drawing down selected wells for long periods of time in advance of hydraulic fracture. This may assure that, when hydraulic fracture operations begin on some other well, shear bands would not propagate towards a drawn-down well because of very high effective stresses resisting shear in the region of that well (Figure 11). Alternation (in space and time) of drawn-down wells and injection wells might result in some control of hydraulic fracture propagation; however, well spacing and effect of draw-down must be carefully evaluated before any conclusions can be drawn.

It is extremely important to recognize the difference between Darcy flow and fracture flow during stimulation, injection, and production cycles. A well production situation can take advantage only of Darcy flow towards the well bore if no propped fracture exists, although gradients can be significant. Fissure flow, which takes place during hydraulic fracture operations (stimulation or injection), would not be reversible when wells are drawn down because fractures reheal (and clog with bitumen) and only Darcy flow can occur. Once the driving force (injection) which has created the fracture ceases, fractures close and flow conditions become dramatically different (Figure 12).

NUMERICAL MODELLING OF HYDRAULIC FRACTURE IN OIL SANDS

The model that has been presented herein is a conceptual geomechanical model based on known behavior of earth materials and data observed during hydraulic fracture operations. The geomechanical model has a certain predictive capability; that is, once the model is fully understood and developed, predictions as to behavior of oil sand during prototype operations may be made. There is a great deal of value in pursuing numerical modelling of oil sands behavior because behavior during hydraulic fracture is scale-dependent. Hydraulic fractures of

100 m diameter at depths of 50 m are different from fractures 400 m in diameter at depths of 400 m (Figure 13). The difference in behavior between the two can be predicted on the basis of appropriate numerical earth models. Among some of the behavioral modes that these earth models should incorporate are shear zone propagation in advance of the hydraulic fracture, strain-weakening behavior, appropriate earth properties. Eventually, pore pressure gradients, shear dilatancy, thermal and transient behavior can be incorporated.

Because of the great difficulties experienced in attempts to obtain undisturbed high quality oil sands specimens for accurate laboratory testing, and because of the lack of any suitable _in situ_ method of obtaining stress strength and deformation properties of oil sand, the appropriateness of the input parameters to numerical models is a topic of some debate. Table 1 is a list of common index and deformation properties of oil sand obtained on fully remolded oil sand, somewhat disturbed oil sand, and extrapolated to probable _in situ_ conditions. It can be seen that order of magnitude differences are evident for certain properties, and the estimated _in situ_ properties are extremely important, but unconfirmed. It would seem that the careful pursuit of superb quality sampling and of _in situ_ test devices would be appropriate considering the extent of the uncertainties and the extent of the problems associated with hydraulic fracture in oil sands. After appropriate data on earth materials behavior have been collected, detailed parametric analyses of the scale-dependent problems can be more fruitful.

Numerical analysis of the problem of compliance of a cement-encased production string embedded in oil sand through which a fracture is passing may also be attempted. Once again, appropriate earth materials properties must be gathered as model input.

SUMMARY

A conceptual geomechanical earth behavior model of the Athabasca Oil Sands during hydraulic fracture has been presented. The major observations and predictions which result from this model are:

1. Major hydraulic fracture orientation is normal to the least principal stress in the earth, providing the least stress is significantly different from the other two principal stresses;
2. Hydraulic fractures open and propagate in such a manner as to minimize work, and lithological variations and sedimentary features can have a second-order effect on hydraulic fracture orientation and propagation;
3. Shear bands exist in advance of fracture planes;
4. Fluid penetration may not occur along shear bands; therefore, temperature and pressure anomalies may not exist in advance of fracture propagation despite significant displacement;
5. Massive multi-well repeated injections for long periods of time in the shallow reservoirs of the McMurray Formation will eventually result in the propagation of horizontal fractures regardless of the initial fracture orientation;

6. There is a high probability that hydraulic fracturing with high temperature liquids creates zones of increased porosity and reduced strength and stiffness as the result of remolding of oil sands;
7. Oil sand fractures tend to self-heal under the lithostatic stresses;
8. Extensive reinjection and fracture widening is extremely probable in cohesionless oil sands fracture operations;
9. Numerical modelling based on a correct geomechanical model will be necessary to examine the consequences of massive fracture operations because of the scale-dependence of the displacements during these operations.
10. The difficulties in prediction of behavior of an *in situ* project employing hydraulic fracture are great because of the extreme complexity of the subsurface conditions, lack of knowledge of material properties, inadequate monitoring capability, remoteness from actual process, and many other factors.

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TABLE 1

Properties of Athabasca Oil Sand (Middle Member, Oil-Rich)

Property	Laboratory Value, Highly Disturbed Core Specimens	Probable *In Situ* Value, 300m Depth
Density	1.7-1.8 (lab.)	2.06-2.15 (geophysical)
Oil Content (% wt of mineral) (% total wt)	 16% 13-14%	 16% 14-15%
Water Content (% wt of mineral) (% total weight)	 2-9% (water taken in from drlg. fluid) 2-8%	 2% 1.6%
Saturation	0.65-0.95	1.0
Porosity	0.35-0.45	.30
Median Grain Size	0.17 mm	0.17 mm
Coefficient of Uniformity	1.3-1.7	1.3-1.7
Shear Strength @ 1.0 MPa @ 7.0 MPa	 0.80-1.2 MPa 4.0-5.0 MPa	 1.5-2.5 MPa 8-12 MPa
Compressibility (Cyclic @ 7.0 MPa)	$0.6\text{-}1.5 \times 10^{-6} kPa^{-1}$	$0.2\text{-}0.3 \times 10^{-6} kPa^{-1}$
Static Loading Young's Modulus	10-30 MPa	1.0-3.0 GPa
Dynamic (Geophysical) Young's Modulus	-	4.0-8.0 GPa
Permeability (Water)	10^{-6} to 10^{-8} m/s	$\sim 10^{-11}$ m/s

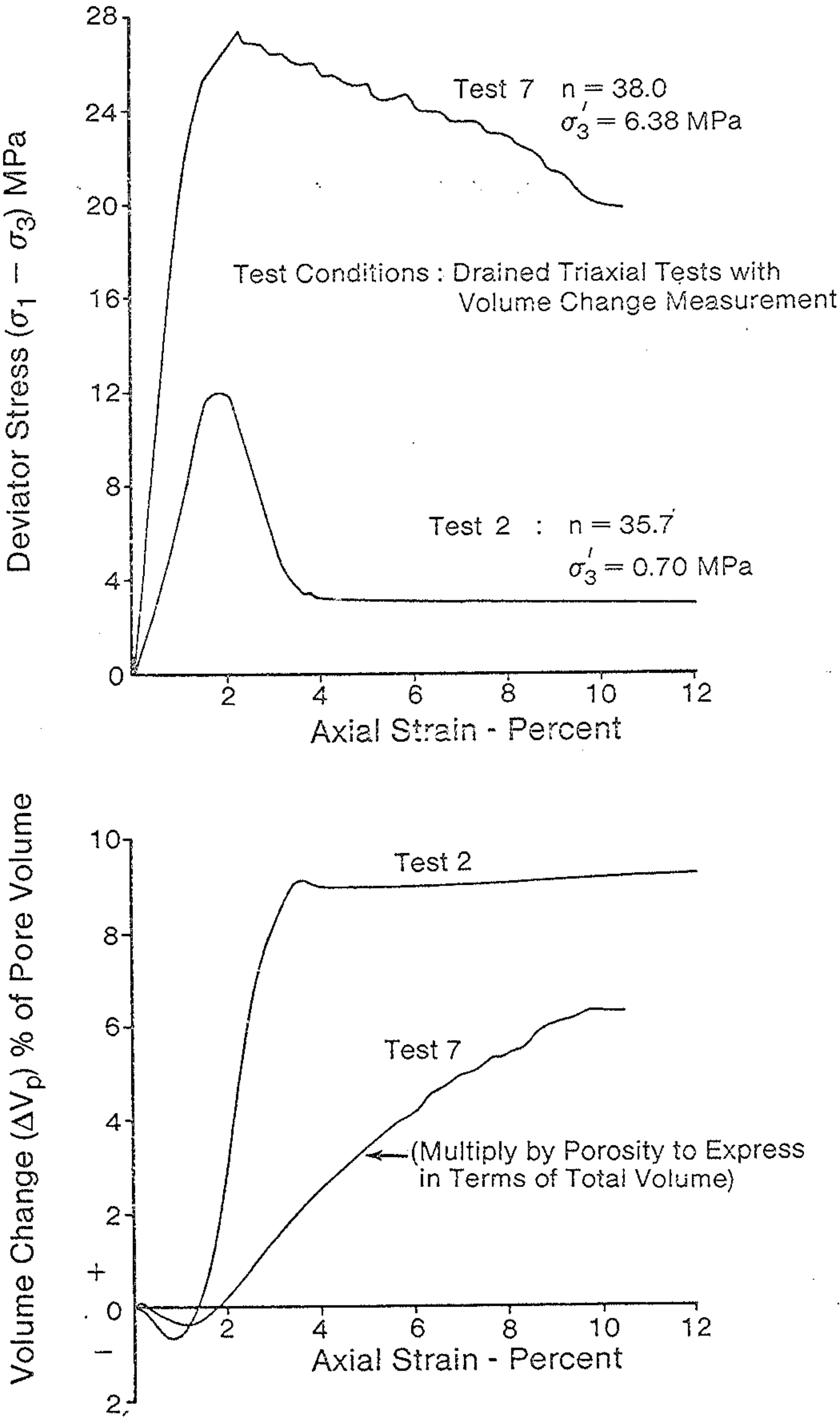


Figure 1 : Drained Triaxial Test Behavior of Oil Sand

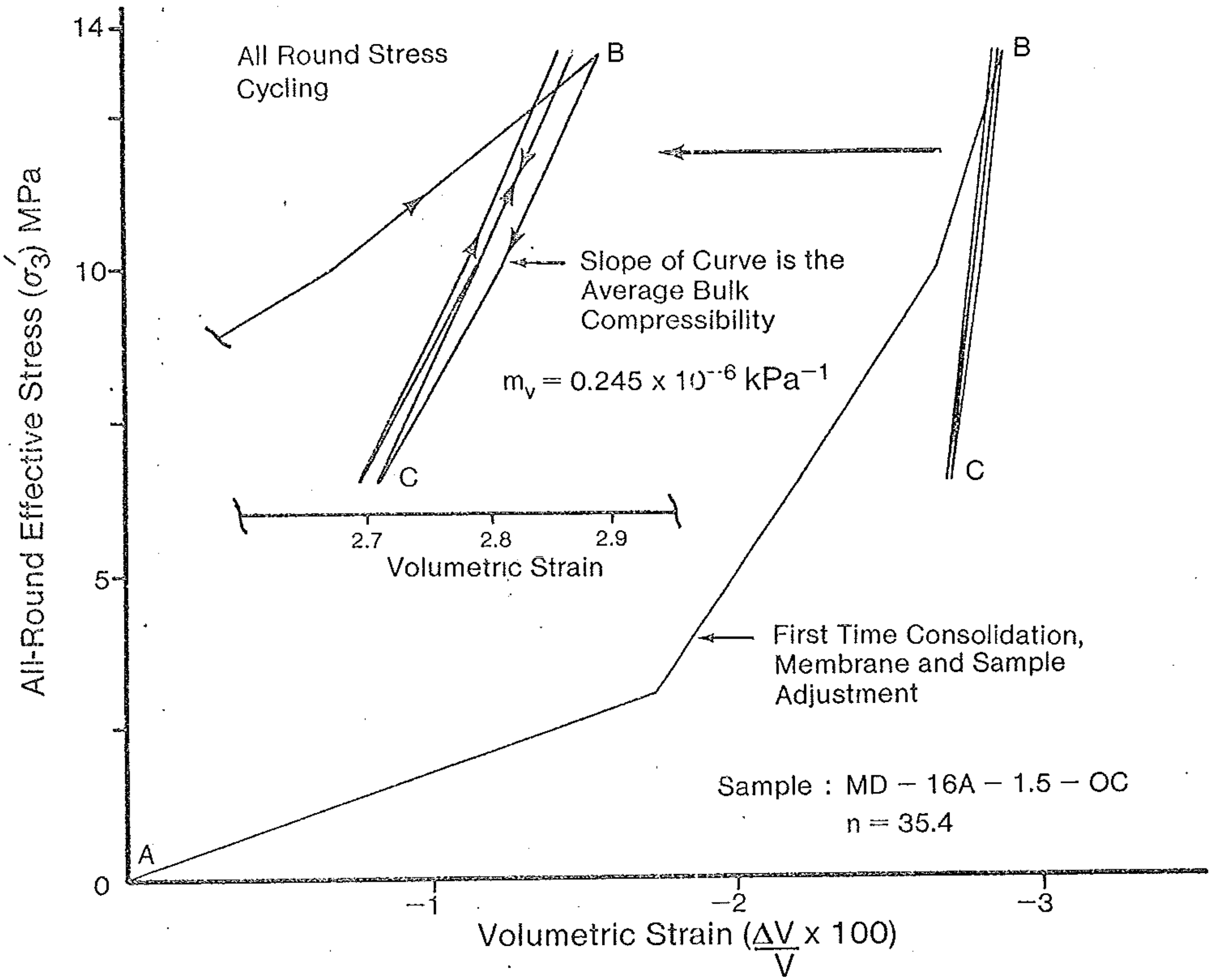


Figure 2 : Typical Bulk Compressibility Behavior of Oil Sand

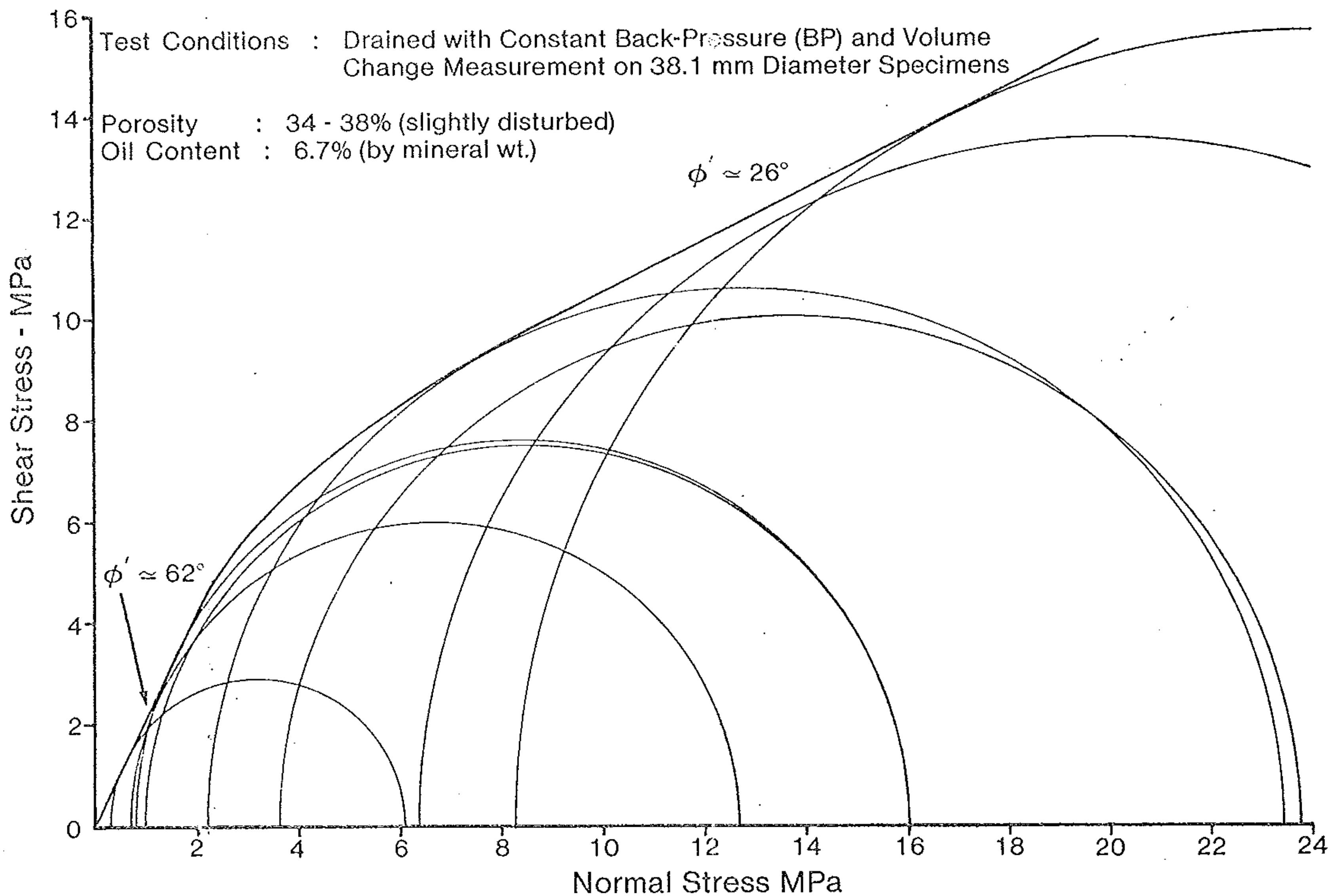
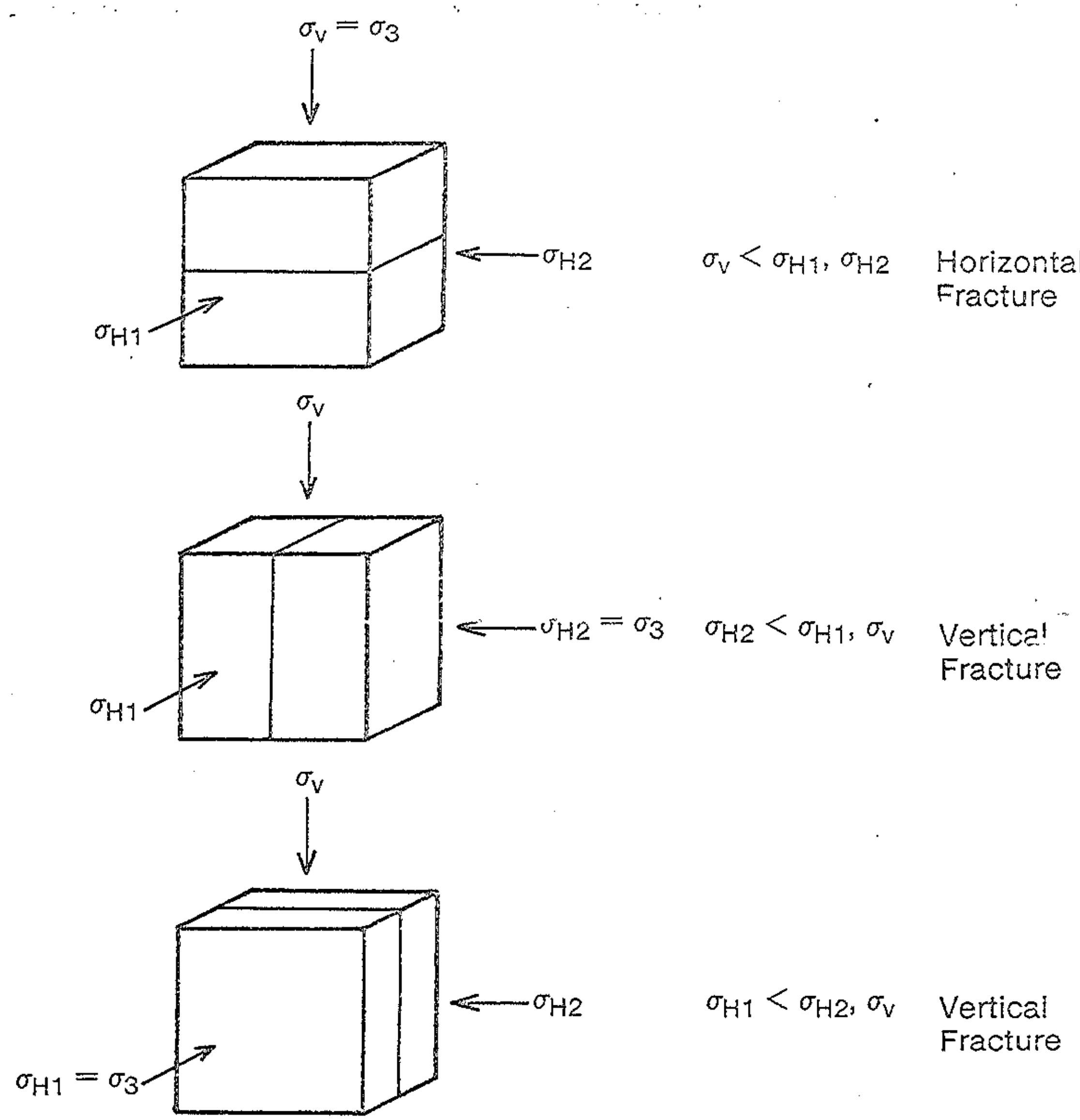


Figure 3 : Mohr - Coulomb Failure Envelope for Triaxial Tests on Oil Sand



Note: Principal stress directions are not a function of pore pressure (i.e.: $\sigma_1 - u > \sigma_2 - u > \sigma_3 - u$). However, effective stress ratios, which control behavior, are a function of pore pressure (i.e.: $\sigma_1 / \sigma_3 \neq \sigma_1 - u / \sigma_3 - u$)

Figure 4: Principal Stress and Fracture Orientation

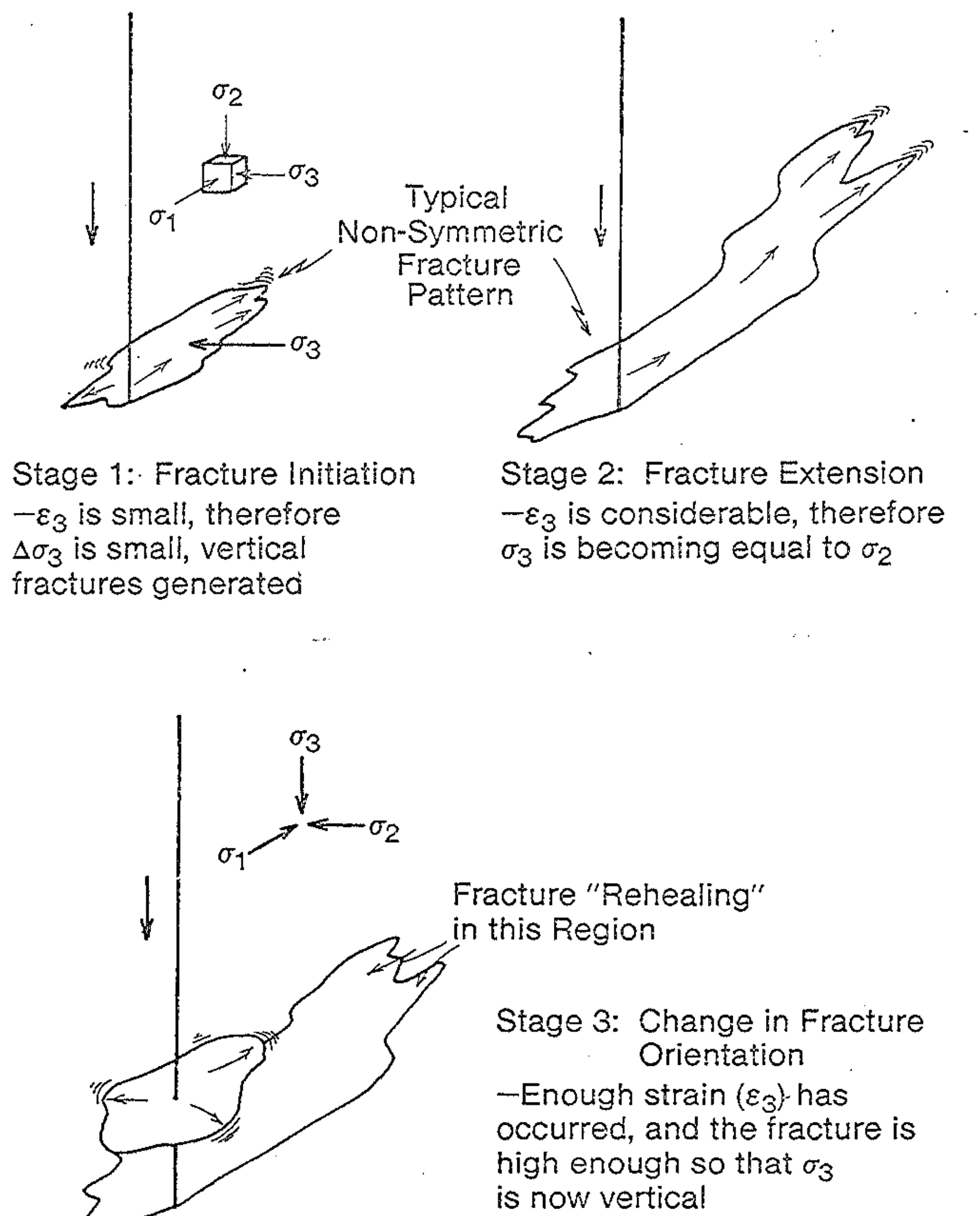


Figure 5: Alteration of Fracture Orientation Because of Stress Field Changes

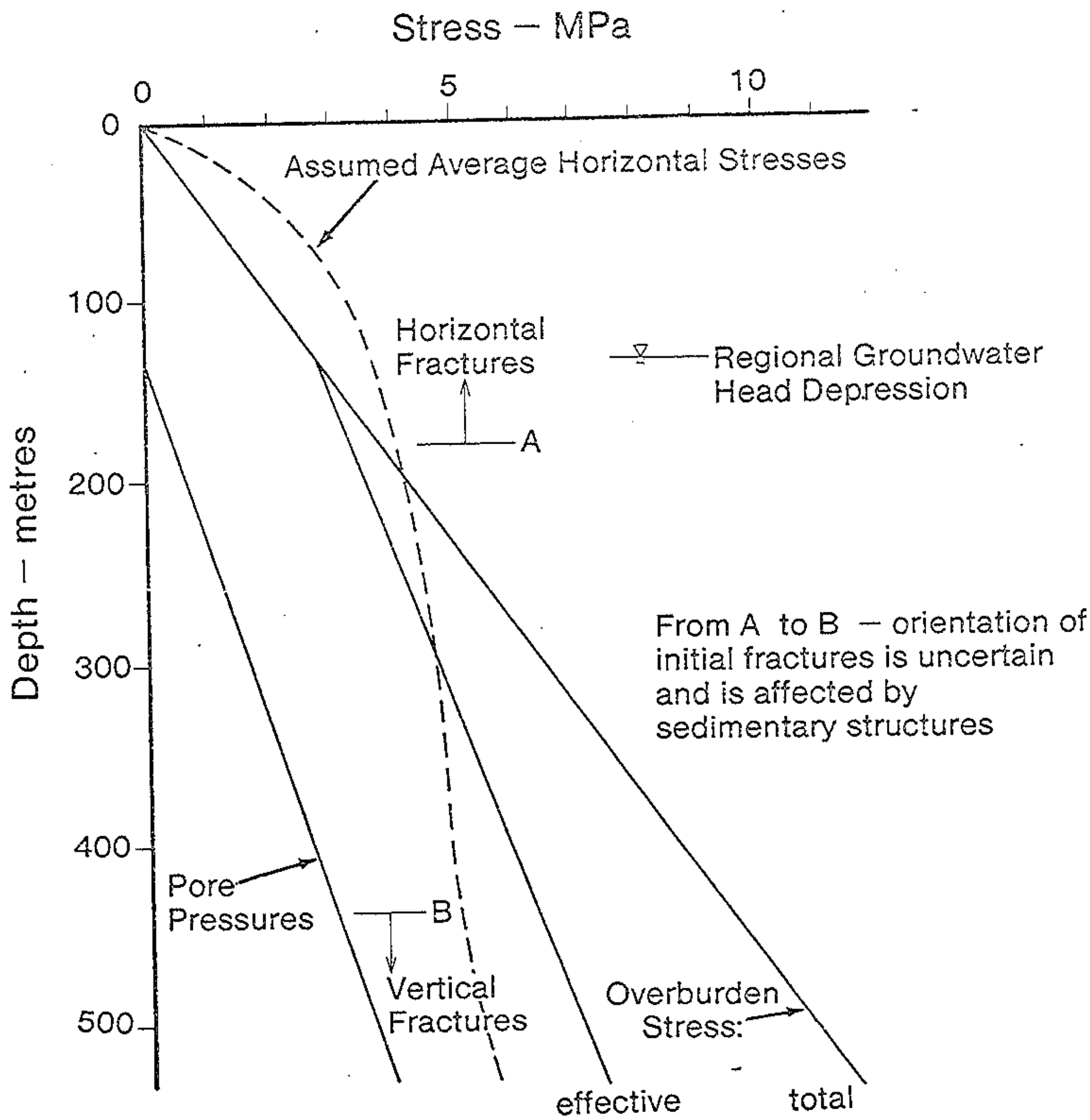
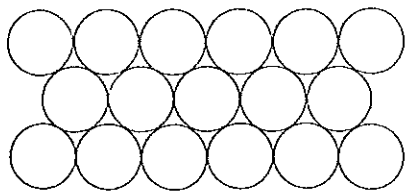
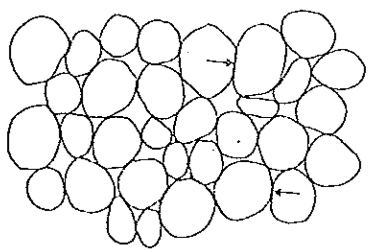


Figure 6: Stress State, Athabasca Deposit
(Note: This diagram is conceptual only; numbers do not
reflect a particular condition or site)



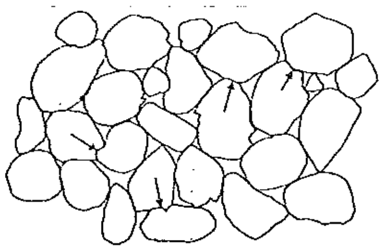
Tangential Contacts (e.g. spheres in contact)

- relatively high porosity and low contact area.
- medium to low dilation during shear.
- normal strengths (friction angle from 26° to 35°).



Long Contacts (e.g. very dense sand)

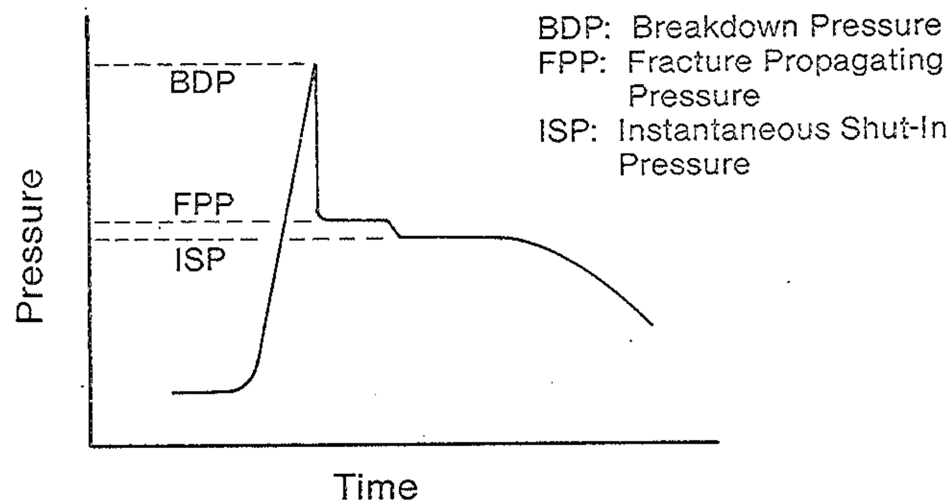
- higher net contact area.
- medium to high dilation during shear.
- high strengths (friction angle from 35° to 45°).



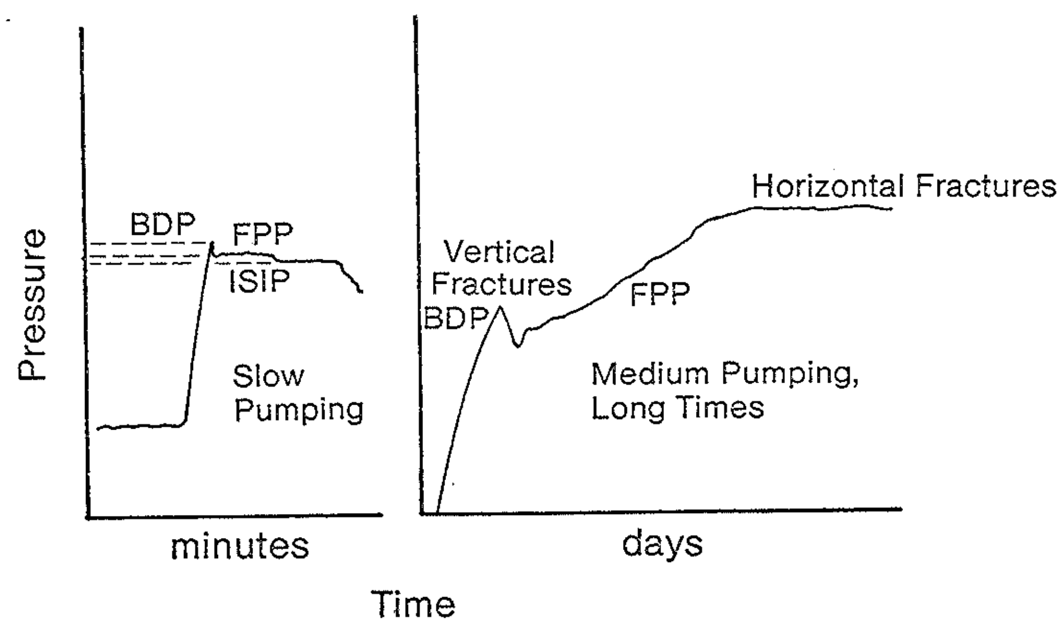
Interpenetrative Contacts (e.g. McMurray Formation sands)

- no true cementation but higher contact area.
- very high dilation during shear.
- very high strengths but no true cohesion.

[illegible] Fabric and Engineering Behaviour

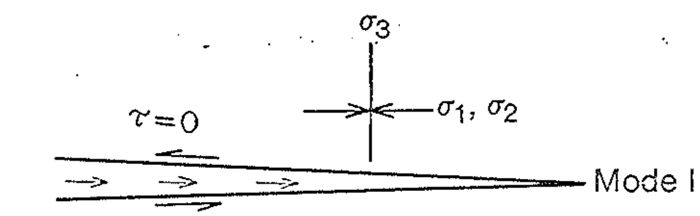


Ideal P-Time Curve for Brittle Rock

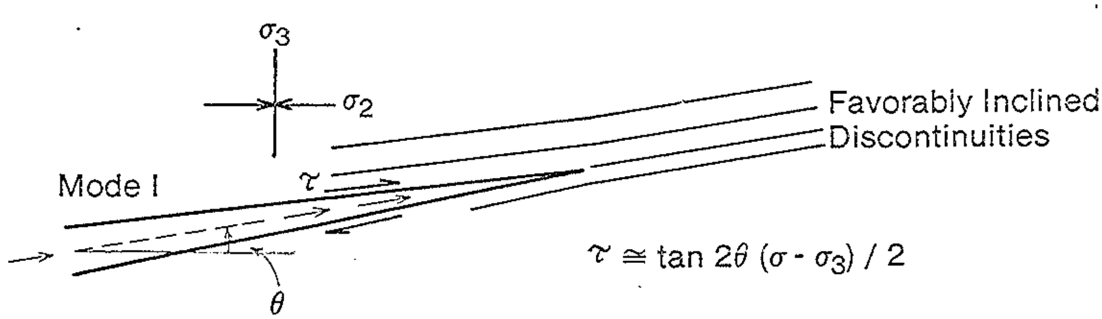


P-T Curves in Oil Sand

Figure 8: Pressure-Time Behavior of Oil Sands During Fracture



When a fracture propagates in a direction orthogonal to the principal stress field, no shear stress is relieved across the fracture, and only Mode I fracture takes place



When a fracture propagates upwards (see Figure 10) to minimize work, shear stresses are relieved which must result in displacement and a zone of shear stress concentration at and in advance of the fracture tip

If the shear stresses are sufficiently large, Mode II failure takes place. In a strength-softening material, this leads to stick-slip phenomena which generate seismic energy

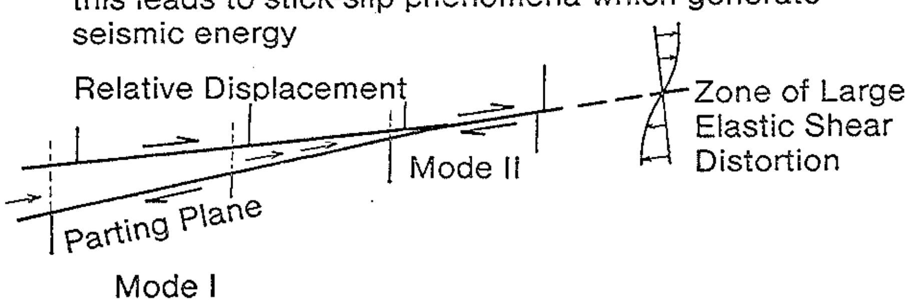
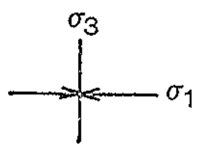
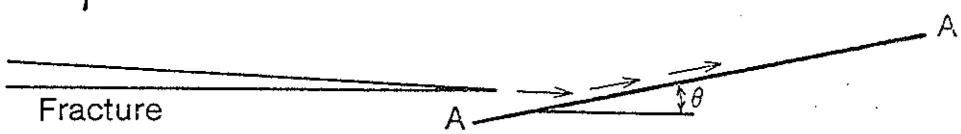


Figure 9: Shear Stresses and Displacements Across Parting Planes

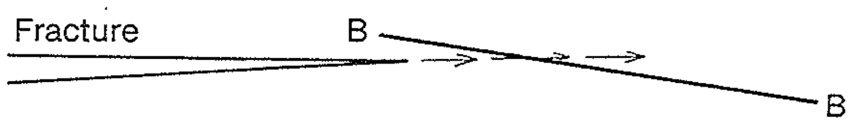


A - A is a favorably inclined feature, either a plane of lower relative shear strength, or the material below A - A has a higher fracture toughness.

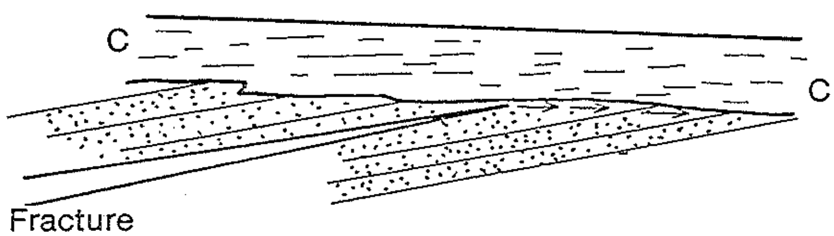


Because σ_3 is less higher in the earth, the fracture can climb at some angle and expend less energy than for horizontal propagation.

B - B is an unfavorably inclined feature.



Because a downward fracture deflection means σ_3 ($= \sigma_V$) is greater, it is improbable that fractures will "dive". Rather, they will propagate through the weak zone.



C - C is a clayey bed of greater relative fracture toughness, therefore a shallow-rising fracture will skid along the interface to minimize energy expenditure.

Figure 10: Lithologic Control on Horizontal Fractures in a Weakly Anisotropic Stress Field

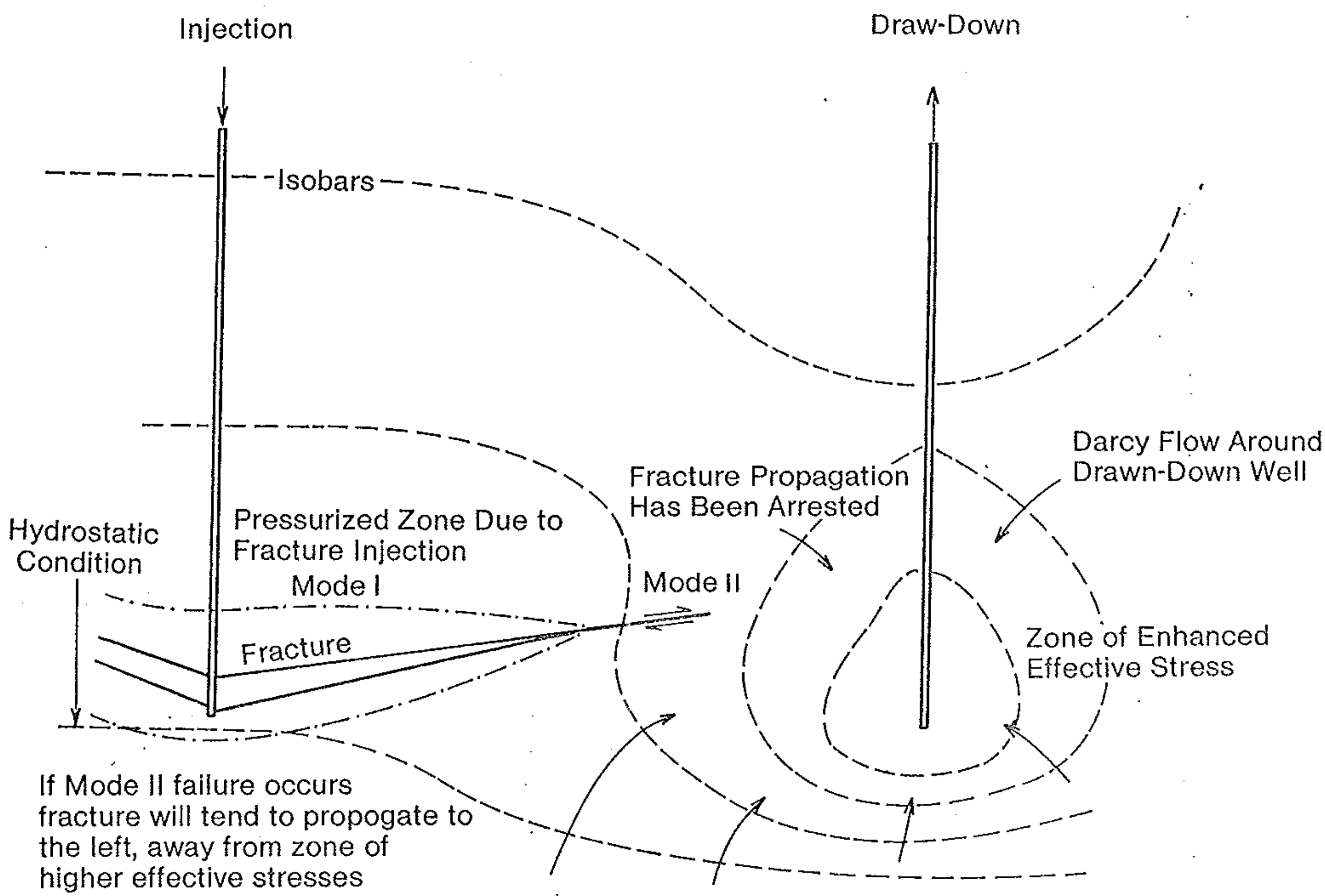


Figure 11: Control of Mode II Fracture by Draw-Down (Optimizing Production Strategy)

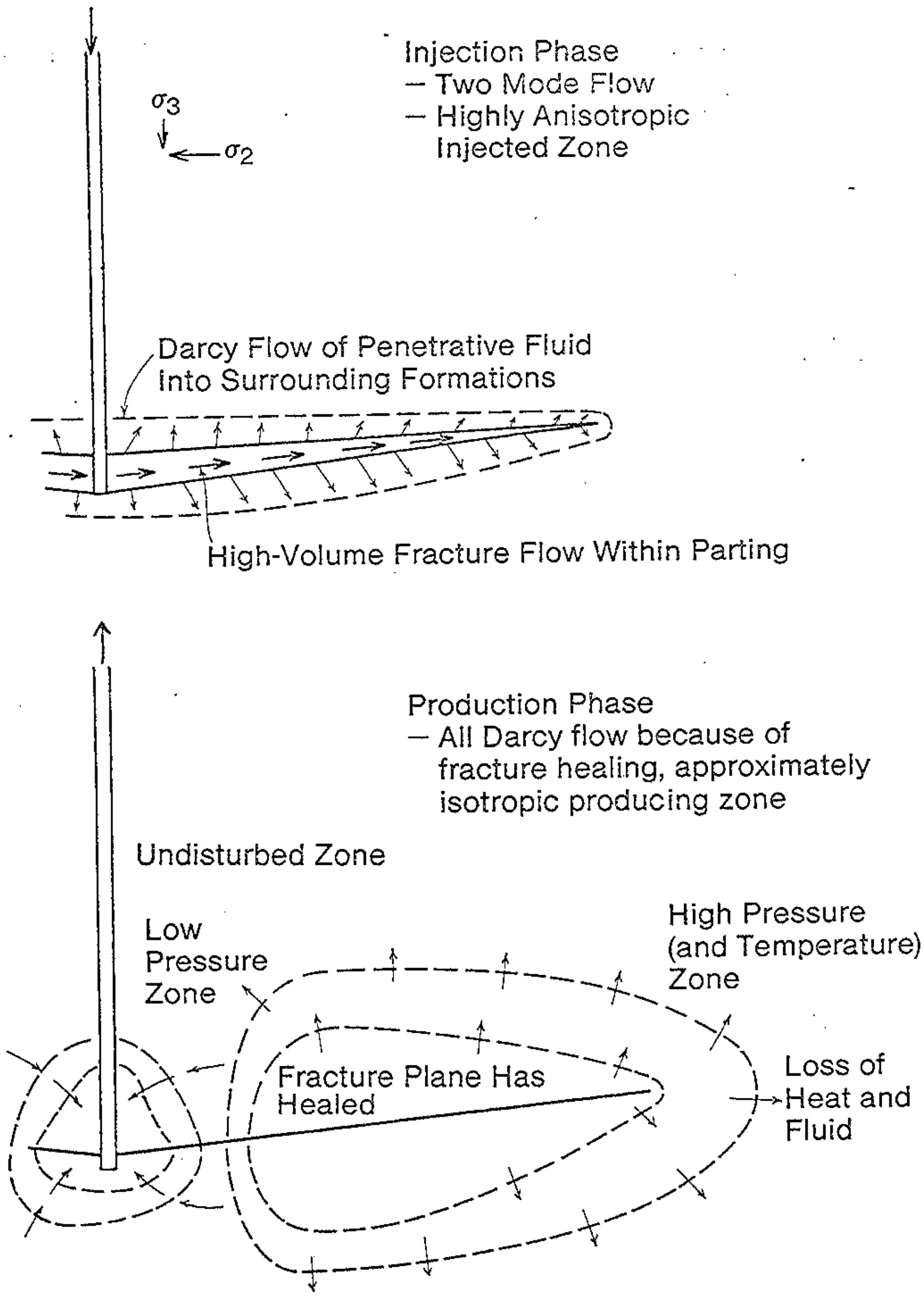


Figure 12: Darcy Flow and Fracture Flow in Unpropped Oil Sands

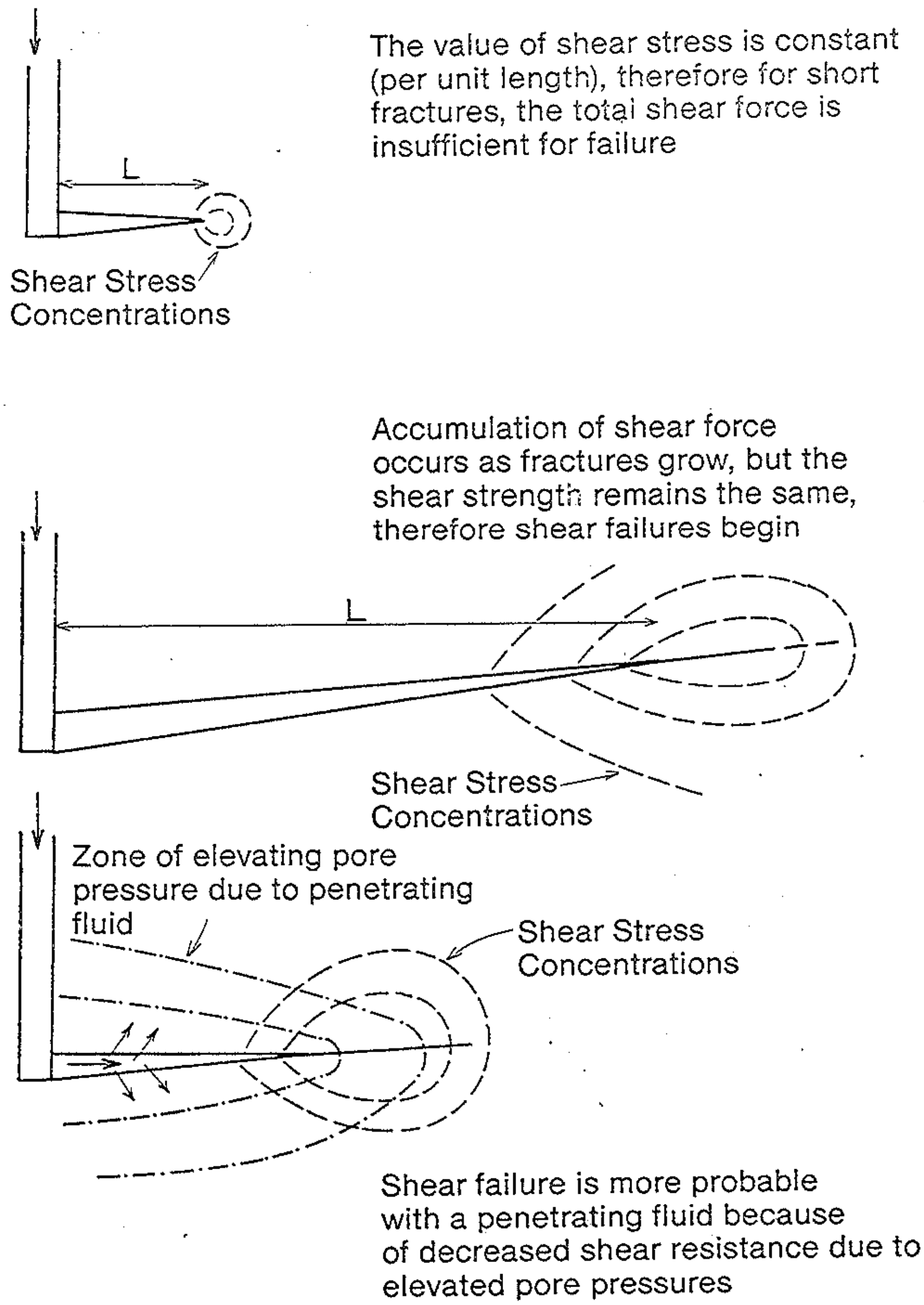
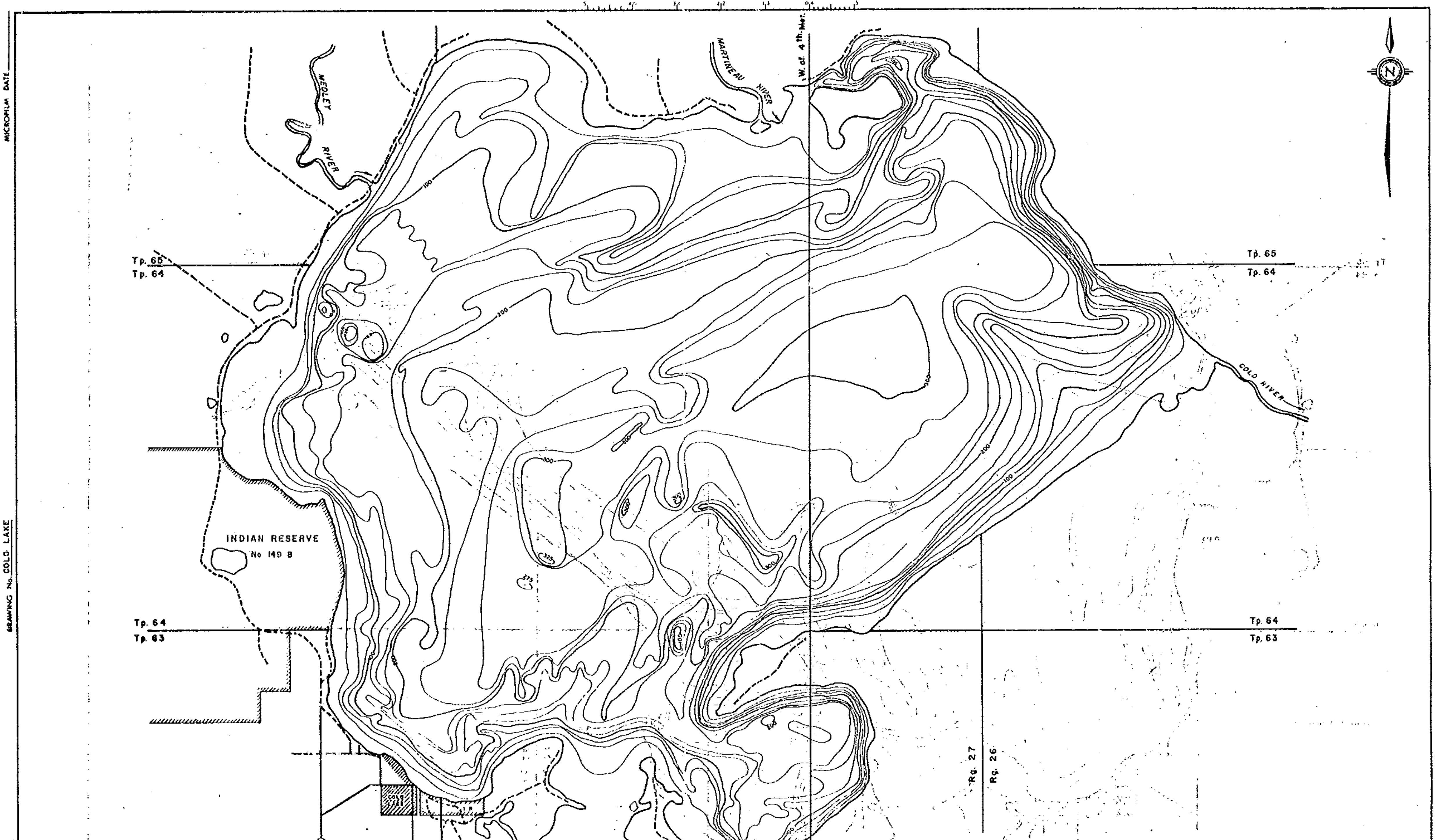


Figure 13: Scale and Pore Pressure Effects on Shear Fractures



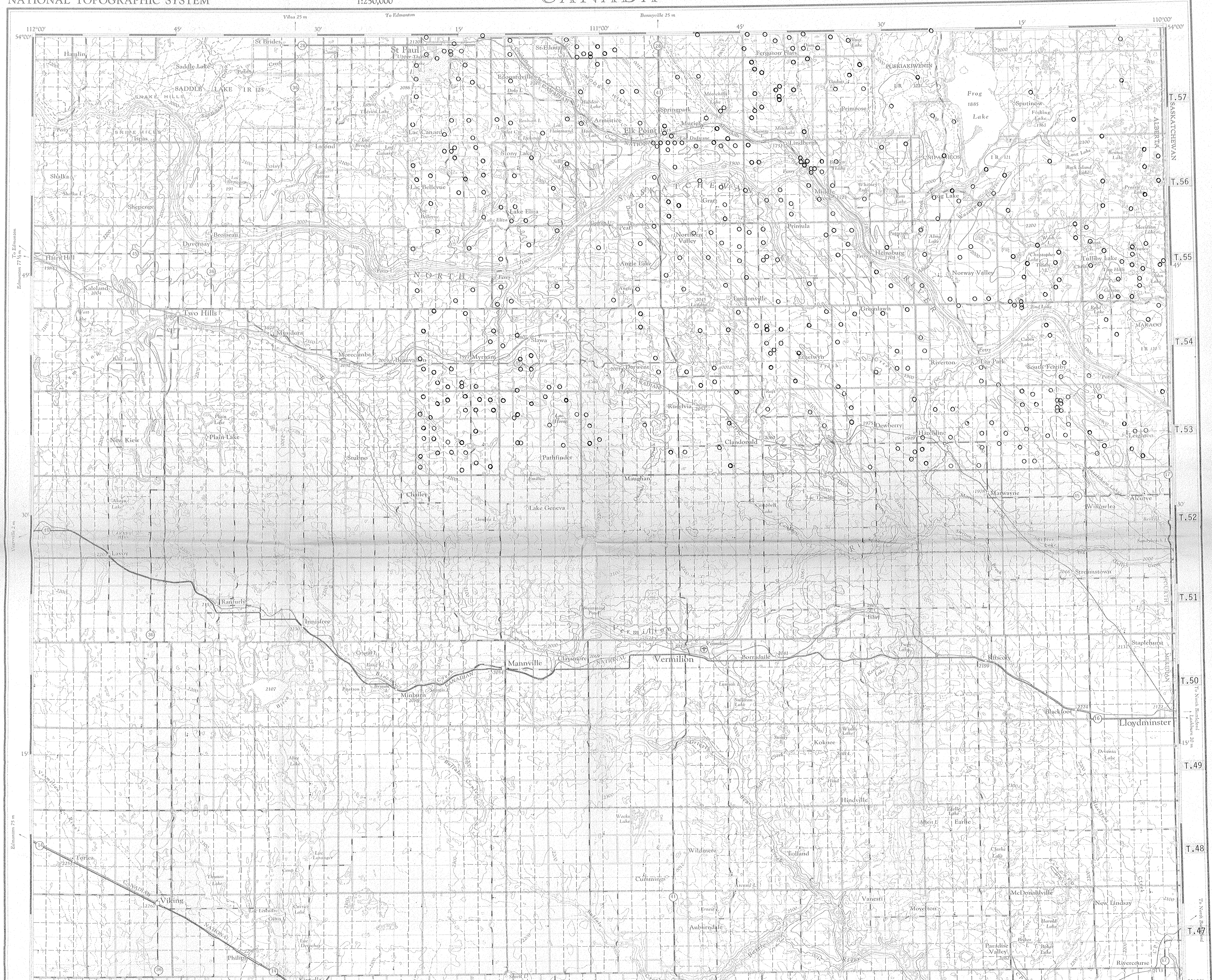
Alberta ENVIRONMENT	HYDROGRAPHIC SURVEY
	COLD LAKE
	Tp. 64 – Rg 26 – W / 3 Mer.
SUBMITTED / DATE	DESIGNED / CHECKED
APPROVED / DATE	DRAWN B. HEDENUS / TRACED S. SCHOEN
SCALE	SHEET 1 OF 1
DATE JUNE, 1973	PLATE 16

MICROFILM DATE

DRAWING No. COLD LAKE

FILE No.

NATIONAL TOPOGRAPHIC SYSTEM 1:250,000 CANADA FIRST EDITION SHEET 73 E



VERMILION

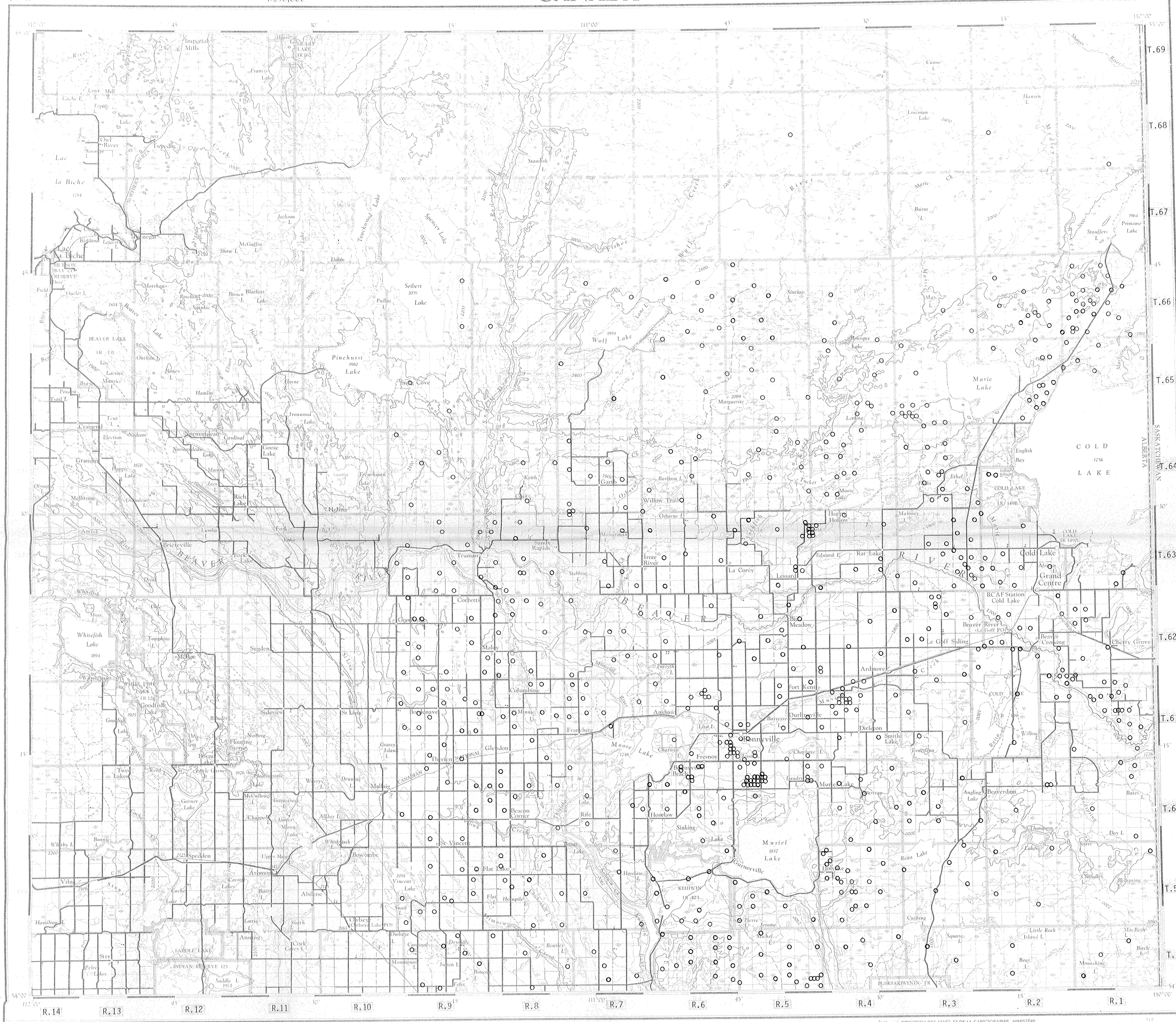
LOCATION OF OIL COMPANY ELECTRIC LOGS

SCALE: 1:250,000

73 L 1:250,000

CANADA

EDITION 2 73 L



SAND RIVER

LOCATION OF OIL COMPANY ELECTRIC LOGS

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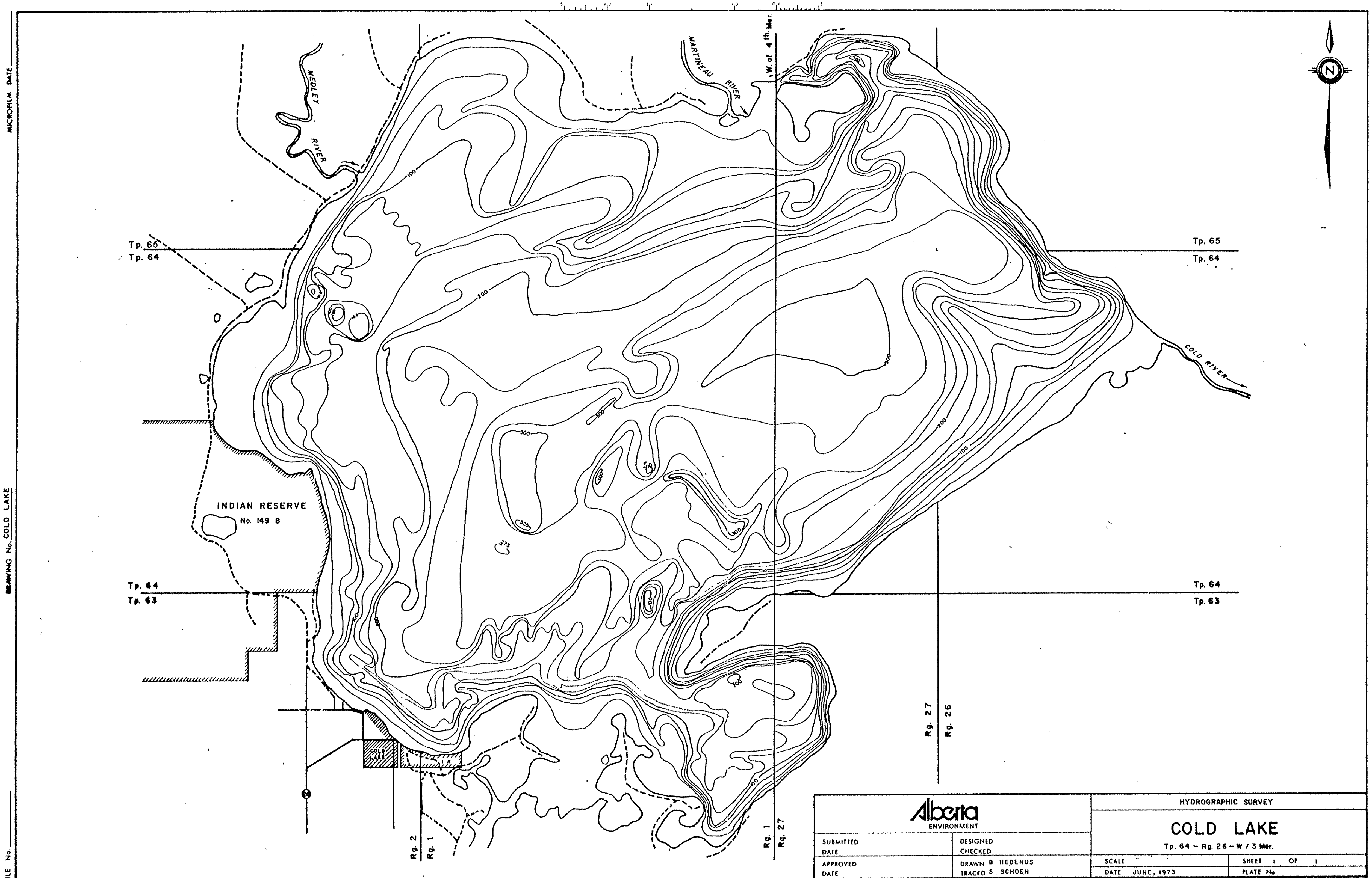
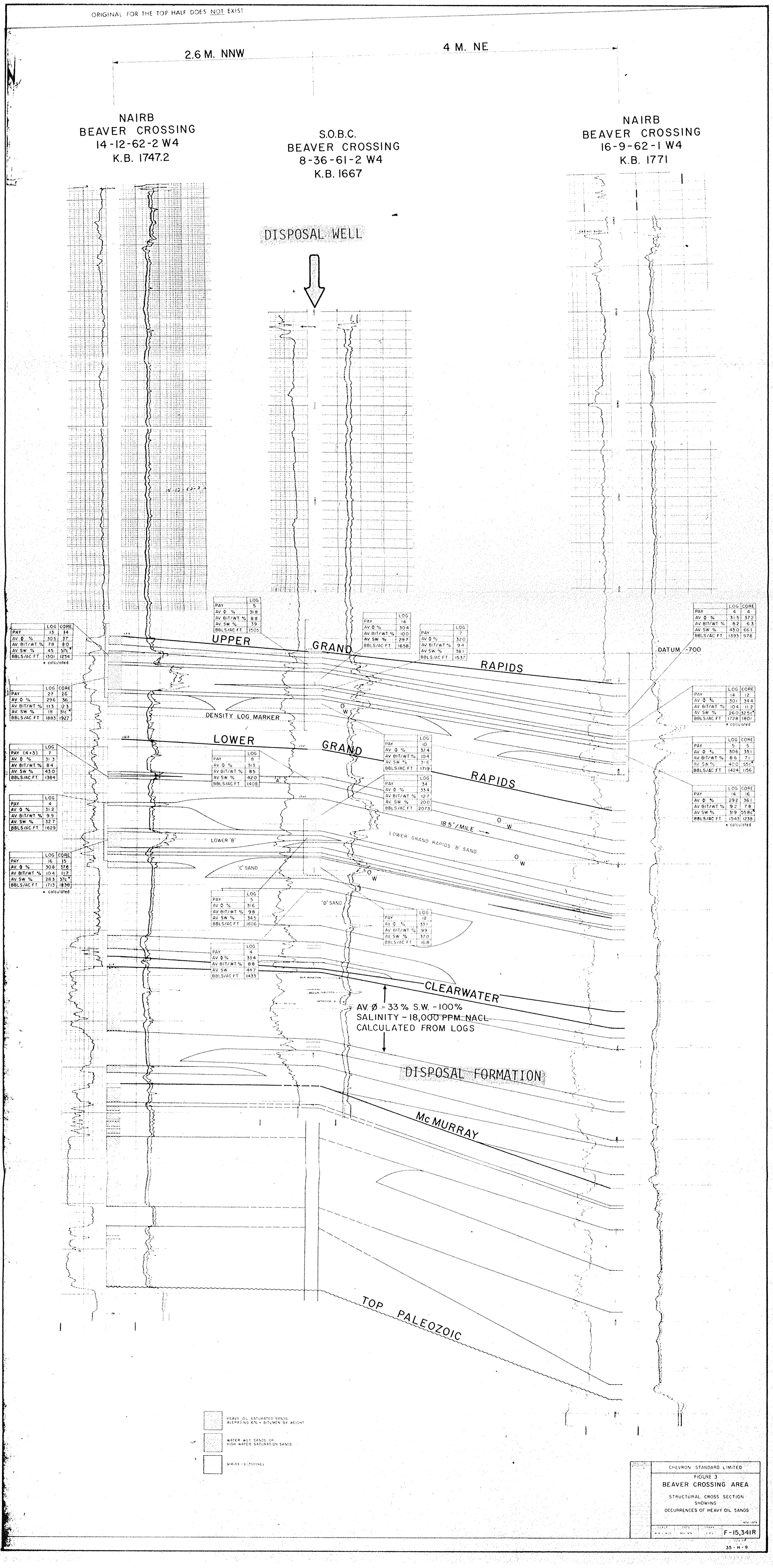
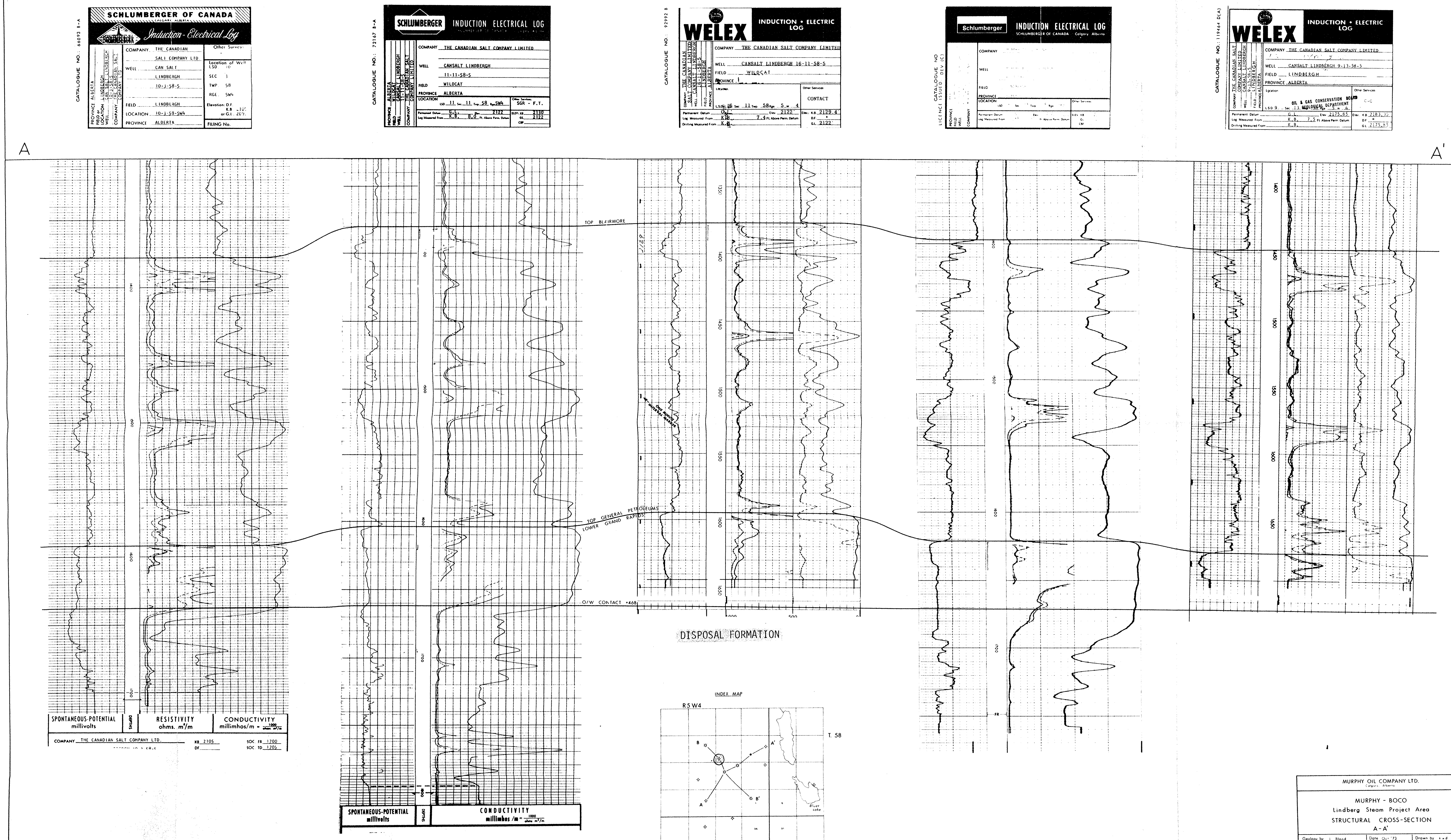


MICROFILM DATE
DRAWING No. COLD LAKE
FILE No.
MEDLEY RIVER
MARTINEAU RIVER
W. of 4 th. Mer.
Tp. 65
Tp. 64
Tp. 63
INDIAN RESERVE
No. 149 B
COLD RIVER
100
200
300
325
275
Rg. 27
Rg. 26
Rg. 2
Rg. 1
COLD LAKE
Alberta
ENVIRONMENT
SUBMITTED
DATE
APPROVED
DATE
DESIGNED
CHECKED
DRAWN B HEDENUS
TRACED S. SCHOEN
HYDROGRAPHIC SURVEY
COLD LAKE
Tp. 64 – Rg. 26 – W / 3 Mer.
SCALE
DATE JUNE, 1973
SHEET 1 OF 1
PLATE No

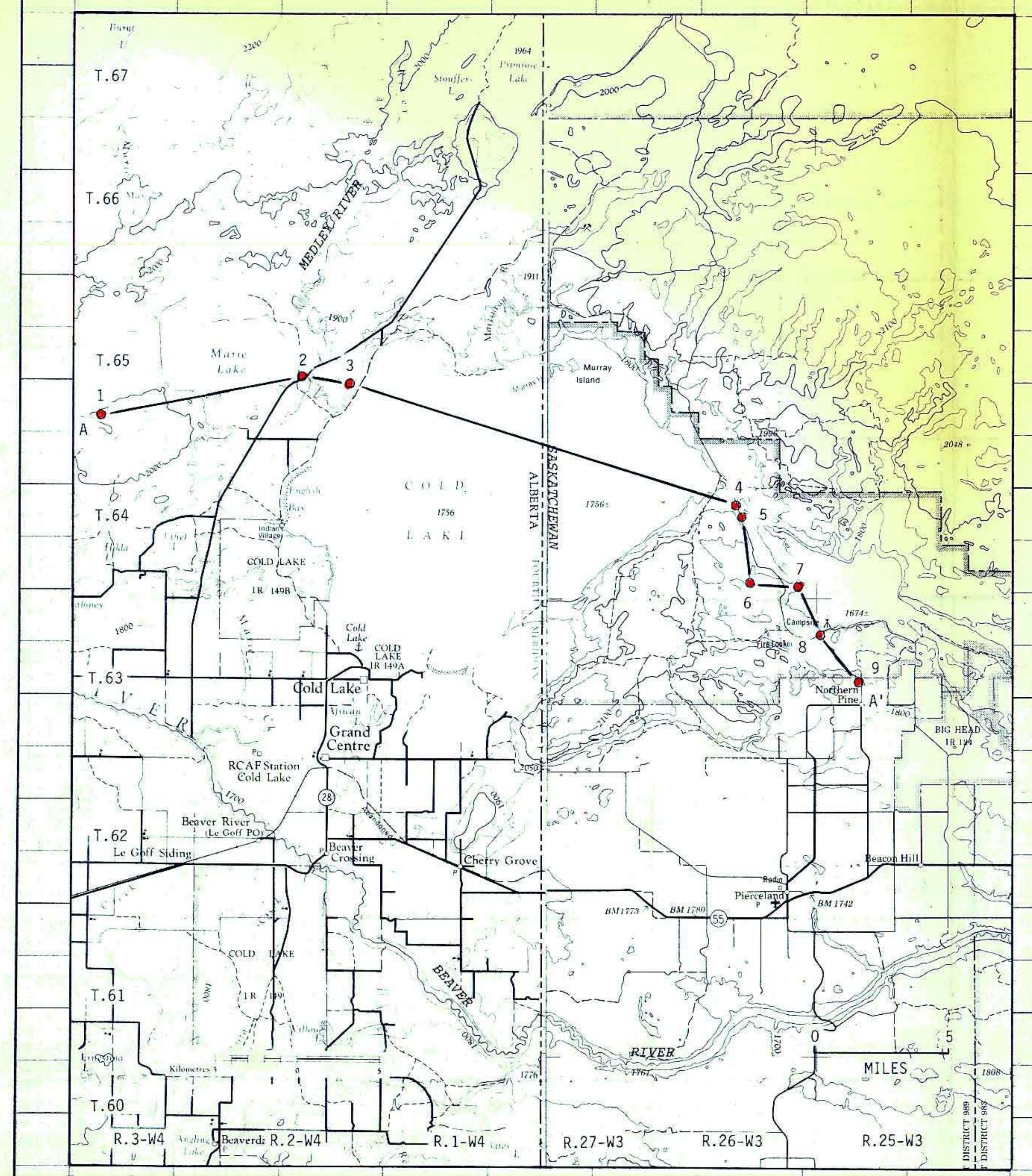

ORIGINAL FOR THE TOP HALF DOES NOT EXIST
2.6 M. NNW
4 M. NE
NAIRB
BEAVER CROSSING
14-12-62-2 W4
K.B. 1747.2
S.O.B.C.
BEAVER CROSSING
8-36-61-2 W4
K.B. 1667
NAIRB
BEAVER CROSSING
16-9-62-1 W4
K.B. 1771
DISPOSAL WELL
LOG CORE
PAY 13 14
AV. Φ % 30.5 37
AV. BIT/WT. % 7.8 8.0
AV. SW % 45 57c*
BBLS/AC.FT. 1301 1234
* calculated
LOG CORE
PAY 27 26
AV. Φ % 29.6 36
AV. BIT/WT. % 11.3 12.3
AV. SW % 18 31c*
BBLS/AC.FT. 1883 1927
LOG
PAY (4+3) 7
AV. Φ % 31.3
AV. BIT/WT. % 8.4
AV. SW % 43.0
BBLS/AC.FT. 1384
LOG
PAY 4
AV. Φ % 31.2
AV. BIT/WT. % 9.9
AV. SW % 32.7
BBLS/AC.FT. 1629
LOG CORE
PAY 16 15
AV. Φ % 30.8 37.6
AV. BIT/WT. % 10.4 11.7
AV. SW % 28.3 37c*
BBLS/AC.FT. 1713 1838
* calculated
LOG
PAY 5
AV Φ % 31.8
AV. BIT/WT. % 8.8
AV. SW % 39
BBLS/AC.FT. 1505
LOG
PAY 14
AV Φ % 30.4
AV BIT/WT % 10.0
AV SW % 29.7
BBLS/AC.FT 1658
LOG
PAY 7
AV Φ % 32.0
AV BIT/WT % 9.4
AV SW % 38.1
BBLS/AC.FT. 1537
UPPER GRAND RAPIDS
DATUM -700
DENSITY LOG MARKER
O W
LOWER GRAND RAPIDS
LOG
PAY 8
AV Φ % 31.3
AV BIT/WT. % 8.5
AV SW % 42.0
BBLS/AC.FT 1408
'A'
LOG
PAY 10
AV Φ % 32.4
AV BIT/WT % 10.4
AV SW % 31.6
BBLS/AC.FT 1719
LOG
PAY 34
AV Φ % 33.4
AV BIT/WT % 12.7
AV SW % 20.0
BBLS/AC.FT 2073
18.5'/MILE
LOWER GRAND RAPIDS 'B' SAND
LOWER 'B'
'C' SAND
'D' SAND
LOG
PAY 5
AV Φ % 31.6
AV BIT/WT. % 9.8
AV SW % 34.5
BBLS/AC.FT 1606
LOG
PAY 18
AV Φ % 33.1
AV BIT/WT % 9.9
AV SW % 37.0
BBLS/AC.FT 1618
LOG
PAY 4
AV Φ % 33.4
AV BIT/WT % 8.8
AV SW 44.7
BBLS/AC.FT 1433
LOG CORE
PAY 4 4
AV Φ % 31.5 37.2
AV BIT/WT % 8.2 6.3
AV SW % 43.0 66.1
BBLS/AC.FT. 1393 978
LOG CORE
PAY 14 12
AV Φ % 30.1 34.4
AV BIT/WT % 10.4 11.2
AV SW % 26.0 32.5c*
BBLS/AC.FT 1728 1801
* calculated
LOG CORE
PAY 5 5
AV Φ % 30.6 33.1
AV BIT/WT % 8.6 7.1
AV SW % 40.0 55c*
BBLS/AC.FT 1424 1156
LOG CORE
PAY 14 16
AV Φ % 29.2 36.1
AV BIT/WT % 9.2 7.8
AV SW % 31.9 55.8c*
BBLS/AC.FT 1543 1238
* calculated
CLEARWATER
AV. Ø - 33% S.W. - 100%
SALINITY - 18,000 PPM NACL
CALCULATED FROM LOGS
DISPOSAL FORMATION
McMURRAY
TOP PALEOZOIC
HEAVY OIL SATURATED SANDS AVERAGING 6% + BITUMEN BY WEIGHT
WATER WET SANDS OR HIGH WATER SATURATION SANDS
SHALES + SILTSTONES
CHEVRON STANDARD LIMITED
FIGURE 3
BEAVER CROSSING AREA
STRUCTURAL CROSS SECTION
SHOWING
OCCURRENCES OF HEAVY OIL SANDS
F-15,341R
35-H-9



MURPHY OIL COMPANY LTD.
Calgary, Alberta

MURPHY - BOCO
Lindberg Steam Project Area
STRUCTURAL CROSS-SECTION
A-A'

Geology by L. Blond	Date Oct '73	Drawn by k.w.d
Revised	Date	Map No. 269
Contour Interval	Scale	Base



LOCATION OF CROSS SECTION AA'