REVIEW OF GROUNDWATER INFORMATION ASSOCIATED WITH IN SITU RECOVERY

SUBMITTED TO

ALBERTA OIL SANDS ENVIRONMENTAL RESEARCH PROGRAM (AOSERP)

BY

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ABBREVIATIONS USED IN THIS REPORT FOR GEOLOGICAL FORMATIONS

Symbol	Stratigraphic Unit
Pleistocene and Recent	
Qd	Glacial drift
Cretaceous	
Ks	Smoky Group
Klb	La Biche Formation
Kd	Dunvegan Formation
Ksh	Shaftesbury Formation
Kpl	Pelican Formation
Kj	Joli Fou Formation
Kg	Grand Rapids Formation
Kc	Clearwater Formation
Kw	Wabiskaw Member
Km	McMurray Formation
Devonian	
Dwd	Woodbend Group
Dbl	Beaverhill Lake Formation
Dsw	Slave Point Formation & Fort Vermilion Formation & Watt Mountain Formation
Dmk	Muskeg Formation
Dpe	Prairie Evaporite Formation
Dm	Methy Formation (Keg River Formation equivalent)
Dmr	McLean River Formation (Chinchaga Formation equivalent)
Dl	La Loche Formation
Precambrian	
Pe	Undivided

1.0 INTRODUCTION

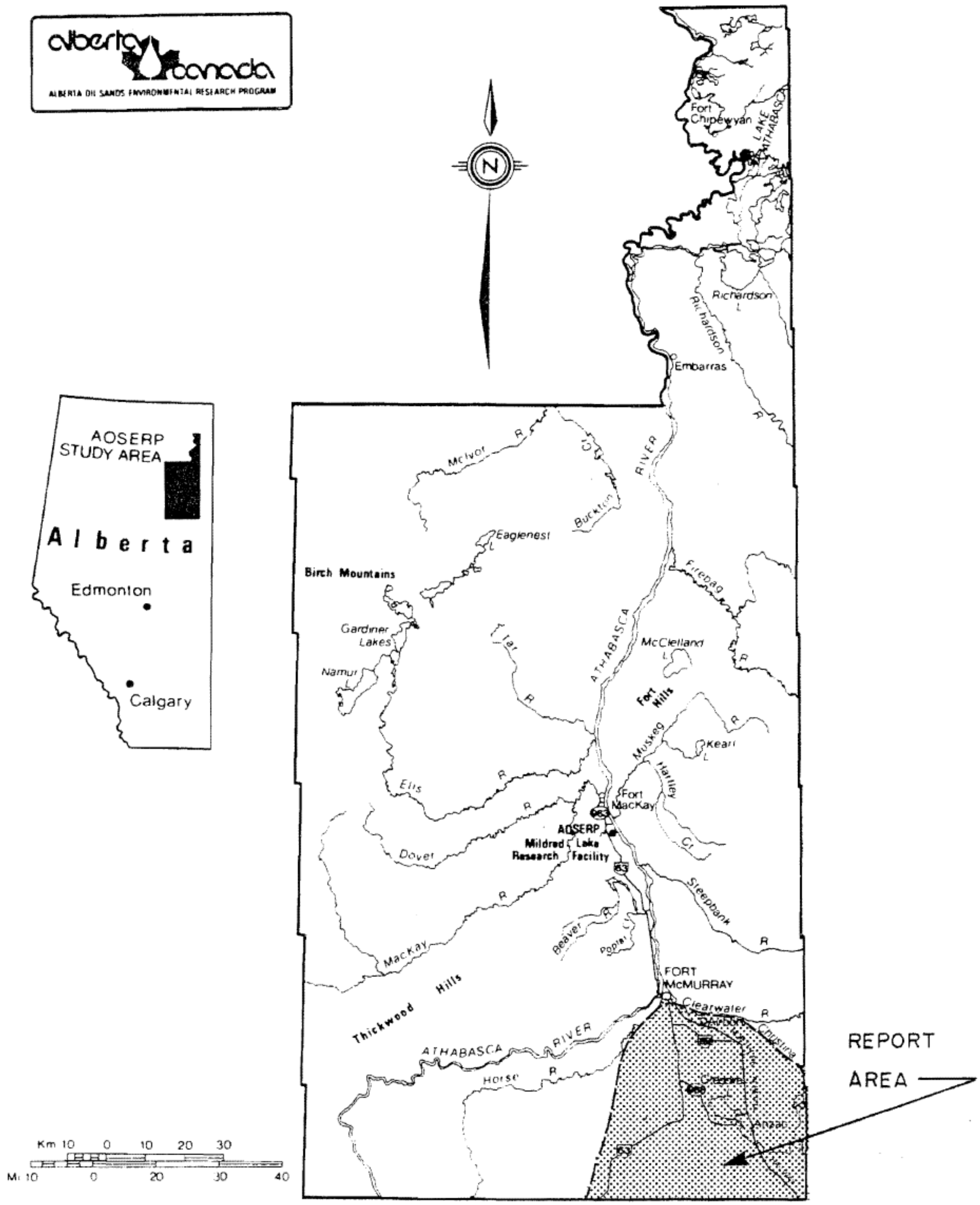
The Athabasca Oil Sands cover an area of approximately 36,000 km^2 and contain an estimated 626 billion barrels of bitumen (approximately 100 billion m^3) in place. Recovery of this bitumen will be undertaken by strip mining where the oil sands are covered by less than 100 m of overburden. The total reserves that can be removed by strip mining are in the order of 74 billion barrels (12 billion m^3). This leaves an estimated 552 billion barrels (88 billion m^3) of bitumen (88%) to be recovered by the in situ process. At the time of preparing this report there were three pilot plants operated by Amoco, Gulf, and Texaco. Because of the size of the reserves and the increasing need to develop domestic oil sources it appears that commercial development will increase significantly over the next few decades.

Such massive-scale development could have substantial effect on the groundwater resources of the region. These changes could, in turn, impact on other environmental parameters. The purpose of this project was to document existing hydrogeological data, identify areas of concern and to outline a plan for monitoring changes in groundwater flow or quality.

The location of the Alberta Oil Sands Environmental Research Program (AOSERP) study area is shown in figure 1-1. Figure 1-2 shows the topography of the study area, which is approximately triangular in shape, with the northern apex of the triangle located at the town of Fort McMurray. The western side of the triangle is formed by the Hangingstone River and the eastern side by the Christina River. The base of the triangle is formed by the boundary between townships 82 and 83. This covers an area of approximately 3000 km^2.

The study area is covered by sheet 74D of the 1:250,000 scale series topographic maps and by sheets 74D.6, 74D.11 and 74E.12 of the 1:50,000 scale series.

The main physiographic regions of the area are: the Methy - Portage Plain, to the east; Algar Plain, to the west; and the Stony

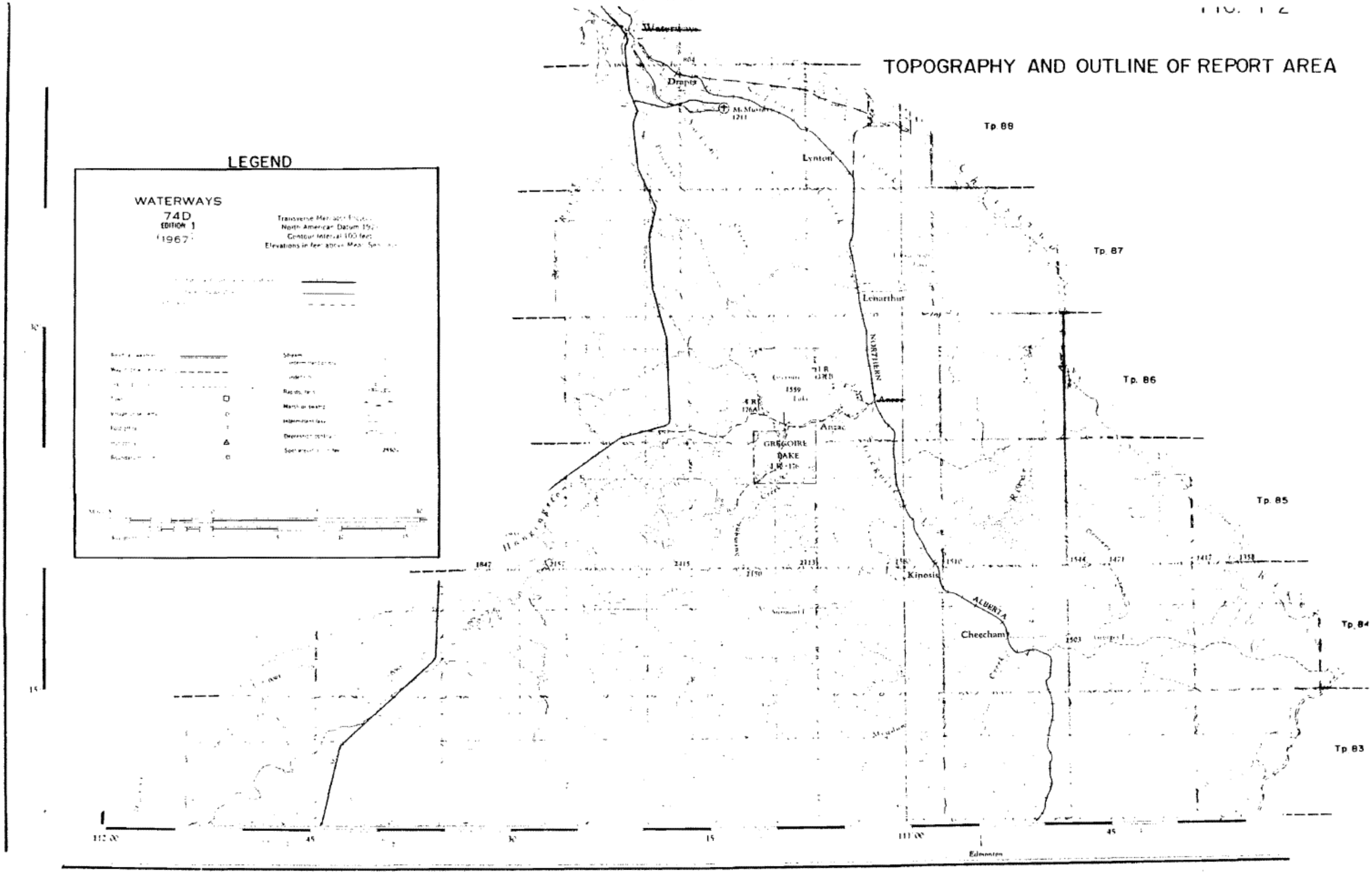


LOCATION OF REPORT AREA WITHIN AOSERP STUDY AREA (See fig. 1-2)

FIG. 1-1

FIG. 1-2

TOPOGRAPHY AND OUTLINE OF REPORT AREA



Mountain upland in the southern part. The northern most part of the area lies in the Clearwater lowland. The upland region starts at an elevation of approximately 600 m and rises to 800 m. The lowest area is the river valley near Fort McMurray where the elevation drops to 250 m.

Drainage of the area forms a parallel/radial pattern, which is focused on Fort McMurray. However, there are numerous areas of internal drainage which are characterized by small lakes and muskeg deposits.

The climate is characterized by long cold winters and short cool summers. The mean annual temperature at Fort McMurray is -0.6 degrees C with a mean of -7 degrees C in January and 16 degrees C in July. There are usually less than 100 frost-free days per year (Longley, 1968) and the first frost usually occurs between mid August and mid September. The average annual precipitation is 437 mm, of which a little more than half falls as rainfall between June and September. Snowfall averages 1500 mm per year and is evenly distributed throughout the year.

2. GEOLOGY

2.1 STRATIGRAPHY

The geology of the area has been studied by many workers, and will not be covered in detail in this report except as it relates to hydrogeology. Areal geology has been mapped by Green et al. (1970) and Carrigy (1959a). Norris (1963 and 1973) should be referred to for details of the Paleozoic geology, while Gorrell (1974) presented a table of formations (Table 1) which included hydrogeological comments. The nomenclature followed in this report is essentially that of Norris (1963 and 1973) and Gorrell (1974).

2.1.1 Precambrian Rocks

Very few wells within or near the study area have been drilled to the Precambrian. Burwash (1957) indicates that a calc-alkali granite was encountered in all the holes that did reach the Precambrian. Carrigy (1959a) has drawn structure contours on the Precambrian surface which shows considerable relief.

Hackbarth and Nastasa (1979) have also contoured the Precambrian surface (Figure 2-1). They have interpreted several faults within the Precambrian, the major one of which runs through the study area, and which has considerable hydrogeological inportance.

2.1.2 Palaeozoic Rocks

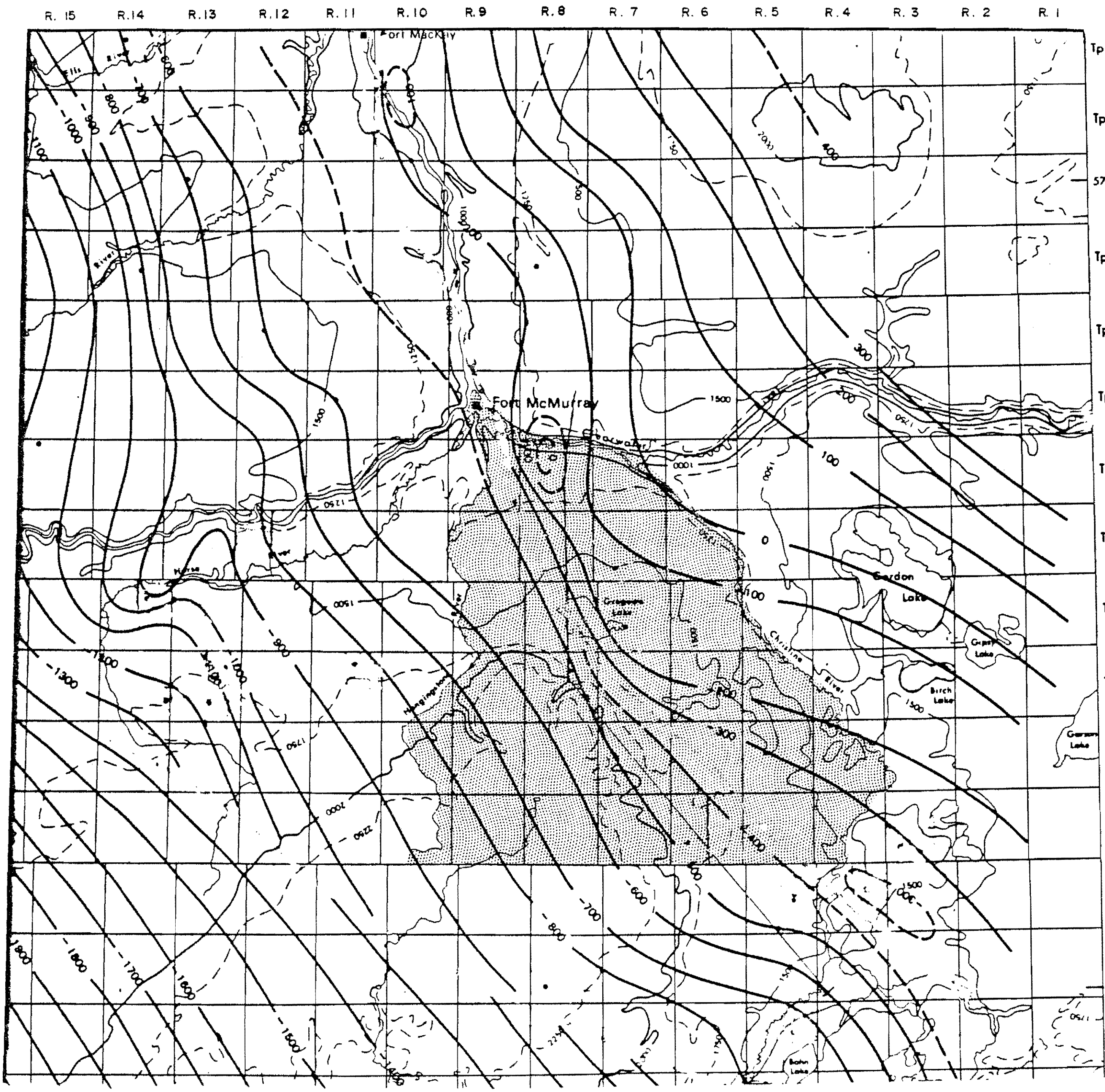
Norris (1973) presented two geological cross-sections which cover the northern part of the study area, and show the Palaeozoic formations that are present (Figure 2-2). A simplified geological section from a line located just north of the Clearwater River is presented by Carrigy and McLaws (1973) which shows the essential features of both Paleozoic and younger stratigraphic units (Figure 3-1).

Table 2-1
TABLE OF FORMATIONS
(from Correll, 1974)

Age	Group Formation Member	Approximate Thickness (Metres)	Lithology	Hydrogeology
CENOZOIC RECENT		0-30+	Muskeg	Very high water content. Serves as recharge blanket.
			Alluvium	Possible source of groundwater.
PLEISTOCENE		0-60+	Till, sand, gravel, clay, boulders.	Granular deposits form good groundwater source.
			---UNCONFORMITY---	
MESOZOIC CRETACEOUS	Grand Rapids	0-90	Sandstone	Near-surface bedrock aquifer. Source of springs in Athabasca valley.
	Clearwater	0-120	Shale	Confining beds.
	Wabiskaw	0-10	Sandstone-glauconitic	Clay cemented, low permeability.
	McMurray	0-105		(Generally impermeable (because of bitumen (content. Local porous (beds.
	Upper		Sand, very fine, silt	
	Middle		Sand, medium, cross-bedded.	
	Lower		Sand, coarse, gravel, silt.	"Lower McMurray aquifer"
			---UNCONFORMITY---	
PALEOZOIC UPPER DEVONIAN	Woodbend	0-180		
	Grosmont		Dolomite-vuggy	Permeable) Present only
	Ireton		Shale	Confining bed) in Western
	Cooking Lake		Limestone	Permeable) part of area
	Beaverhill Lake			
	Waterways	0-210)		
	Mildred	40)		
	Moberly	60+)		
	Christina	25±)	Shale and shaley limestone.	Generally low-permeability.
	Calumet	30±)		
	Firebag	50±)		
MIDDLE DEVONIAN	Slave Point	15	Dolomitic limestone	Locally contains permeable beds.
	Watt Mountain	15	Siltstone	Generally impermeable.
	Upper Elk Point			
	Prairie Evap.	0-240	Salt, gypsum, anhydrite, shale.	An aquiclude where present. Partly removed by solution.
	Methy	0-270	Dolomite, in part reefal.	Locally an important aquifer.
	Lower Elk Point			
	McLean River	60-160	Shale, silty shale.	Aquitard.
	La Loche (Granite Wash)	0-130	Sandstone, arkosic	Aquifer of sporadic distribution.
			---UNCONFORMITY---	
PRECAMBRIAN			Granite-Metasediments	Effectively impermeable.

SURFACE CONTOURS ON PRECAMBRIAN SURFACE

(After Hackbarth & Nastasa 1979)



KEY

– – – – – – Ground surface

—200(61)— Topographic contours Feet (metres)

FIG. 2-1

2.1.2.1 La Loche Formation

Norris (1973) describes the La Loche Formation as:

"The basal Paleozoic beds consisting mainly of arkosic sandstones that nonconformably overlie the Precambrian. In outcrops the sandstone appears to be preserved only in depressions in the Precambrian surface. In the subsurface there is a pronounced thinning of the unit over the tops of local Precambrian highs as is evident in the Alberta Government Salt Well No. 2."

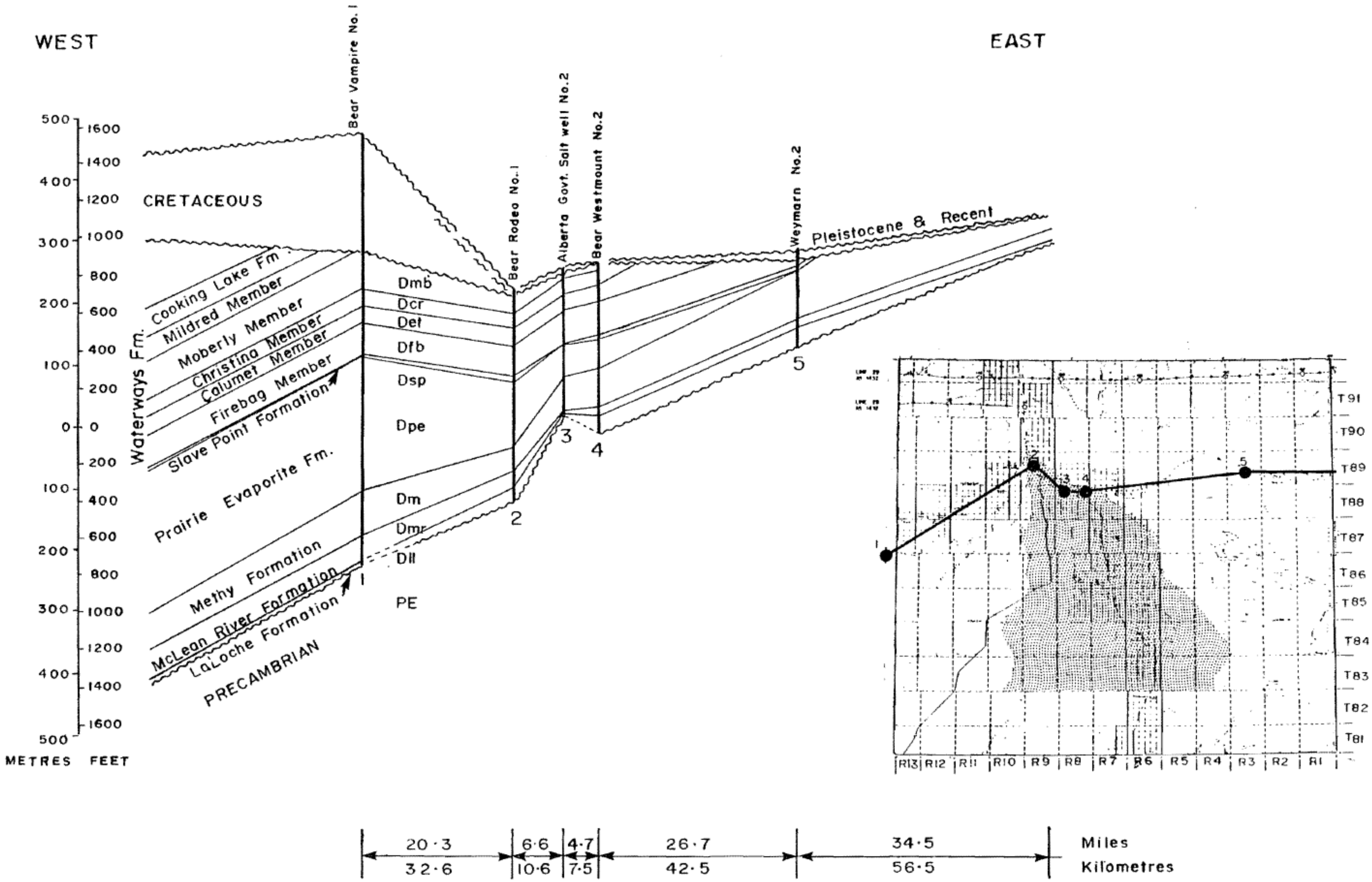
"In the subsurface, the La Loche Formation consists mainly of feldspathic and gritty sandstone, some sandy dolomite, mudstone and shale, and thin minor beds of anhydrite and gypsum."

Norris shows the La Loche Formation to be as little as 1.5 m in thickness in the study area on a local high on the Precambrian surface in the Alberta Government Salt Well No. 2 in 5-32-88-8W4. In the other four wells within the study area which have been logged by Norris, (Figure 2-2) the La Loche Formation is between 22 and 30 m thick and appears to be continuous over the area. Texaco Canada, in their waste injection well in 13-15-88-8W4 have logged a 4 m thickness of the La Loche Formation. The La Loche Formation is the injection zone in this well.

2.1.2.2 McLean River Formation

Norris (1973) describes the lithology of the McLean River Formation as consisting:

"Largely of dolomitic siltstone, some silty and sandy shale, and mudstone, with scattered thin beds of anhydrite and gypsum. In the western parts of the report area beds of dolomite, in part oolitic and brecciated, and thicker sequences of anhydrite are also present", (e.g., Bear Biltmore No. 1 and Bear Vampire No. 1; Figure 2-2).



CROSS SECTION FROM BEAR VAMPIRE No. I WELL TO SASKATCHEWAN

(Modified from Norris, 1973.)

FIG. 2-2

Norris logs a thickness of only 4 m of McLean River Formation in Alberta Government Salt Well No. 2. In the other four wells in the area logged by Norris (Figure 2-2) the McLean River Formation is 16 to 35 m thick. A thickness of 8.5 m has been logged by Texaco Canada in 13-15-88-8W4. Because of its low permeability, this formation forms an aquitard overlying the more permeable La Loche Formation.

2.1.2.3 Methy Formation

The Methy Formation is described by Norris, 1973 as: "Composed mainly of dolomite, underlain by fine clastic beds of the McLean River Formation and overlain by evaporites of the Prairie Evaporite Formation. Eastward, towards the edge of the Canadian Shield, the Prairie Evaporite Formation thins to zero immediately west of the Weymarn No. 1 Well."

"Greiner (1956) recognized three arbitrary subdivisions within the formation: a basal, relatively thin-bedded unit; a relatively thick middle unit containing reefal and interreefal beds; and a relatively thin upper, distinctly-bedded unit in which fossils are apparently absent. The lower units (0.6 to 10.7 m thick) consist of light yellowish grey dolomite and evaporite and silty dolomite with thin interbeds of anhydrite and minor shale. The middle unit (40 to 60 m thick) consists mainly of pale brown to brownish grey dolomite which is in places massive, poorly to well bedded, "flow-layered" and brecciated. The approximate lower half of this unit in the Bear Westmount No. 1 well consists of a dolomitic limestone. The upper unit (1 to 17 m thick) consists, of unfossiliferous well-bedded dolomites, evaporitic dolomite, some oolitic and argillaceous dolomite, and thin interbeds of anhydrite."

In the five wells within the study area logged by Norris, the thickness of the Methy Formation varies from 36.6 m in the Bear Rodeo No. 1 (8-20-89-9W4) to 70.4 m in Bear Westmount No. 1 (14-9-86-7W4). A thickness of 36 m was logged in the Texaco Canada injection well in 13-15-88-8W4.

Gorrell, 1974, has stated that the Methy Formation contains "biothermal reefal buildups ... which are very porous, very permeable, and usually contain highly saline water." He states that the reefal faces is more prevalent towards the east near the edge of the Precambrian Shield. Because of its permeability, the formation has good possibilities as a waste injection zone.

2.1.2.4 Prairie Evaporite Formation

Norris (1973) describes the Prairie Evaporite Formation as: "A unit consisting mainly of evaporites overlying the dolomites of the Methy Formation and underlying the thin limestone and limestone breccia of the Slave Point Formation."

"This rock unit does not outcrop in the Athabasca-Clearwater Rivers area. However, a number of salt springs, probably first mentioned by Bell (1884, p. 27) are present on the banks of the Clearwater River immediately west of the most westerly outcrops of the Methy Formation, where one would expect to find the "feather edge" of the evaporites intersecting the surface. The evaporites are missing from the Weymarn No. 1 Well (Figure 2-5) which is probably located just beyond the eastern margin of the evaporite basin. The Prairie Evaporite Formation is present, however, in all of the wells drilled to the west of the Weymarn No. 1 Well."

The foregoing description applies reasonably well to the lithology of this formation in the eastern part of the area of study. To the west however, the formation consists predominantly of salt. In the Bear Biltmore No. 1 well for example, in 7-11-87-18W4, out of the 212 meters assigned to the formation, 194 meters consists of rock salt. In the Bear Vampire No. 1 well in 7-28-87-12W4, 126 meters out of the 197 meters of the formation is rock salt. Several wells drilled within and south of Ft. McMurray have also encountered considerable salt.

The thickness of the Prairie Evaporite Formation in the report area is expected to vary from as little as 30 m in the eastern part of possibly in excess of 200 m in the southwestern part.

Hamilton, (1971) shows an eastern zero edge of salt trending in a northwest-southeast direction through Ft. McMurray and through Anzac. Salt to the east of this line has been removed from the formation by solution. Hackbarth and Nastasa, (1979) postulate a major fault (termed the Sewetakun Fault) slightly to the west of and parallelling Hamilton's zero edge of salt. Hackbarth and Nastasa state that removal of salt from the Prairie Evaporite Formation is essentially complete to the east of the Sewetakun Fault, although effects of salt solution can still be present for several miles to the southwest of this fault also. Outlies of salt may occur farther east and would be reflected as highs on the erosional Devonian surface (Gorrell, 1974).

Salt solution may have considerable significance hydrogeologically as has been stressed by all authors of hydrogeologically-oriented reports. Salt collapse features could provide vertical conduits for release of waters from the underlying Methy Formation (Gorrell, 1974).

2.1.2.5 Slave Point Formation

Norris (1973) has described the Slave Point Formation as: "A relatively thin rock unit composed of limestone, some silty limestone, silty, and minor dolomitic limestone, in places brecciated."

The formation is quite thin in all the wells logged by Norris, where it varies in thickness from 1.7 to 4.5 m.

2.1.2.6 Waterways Formation

The Waterways Formation has been divided into five members, only the lower four of which are present in the report area. The following descriptions are from Norris, (1973): "The Firebag Member consists mainly of olive green calcareous shale with thin, more resiliant sequences of olive green limestone, argillaceous limestone, and non-calcareous shale. A thin fragmental limestone is commonly present at the base."

"The thickness of the Firebag Member in the type well is 52 m. Wells in the report area show a very slight decrease in thickness for the member from east to west and from north to south."

"The lithology of the Calumet Member consists mainly of grey to buff clastic limestone, variably argillaceous limestone, some olive green nodular calcareous shale, and minor noncalcareous shale. The thickness of the Calumet Member is remarkably uniform throughout the area varying from a minimum of 27 m in the Bear Westmount No. 1 Well to a maximum of 32 m in the Bear Biltmore No. 1 Well."

"The lithology of the Christina Member consists mainly of greenish grey shale, grey argillaceous limestone, pale brown aphanitic limestone, and minor pale brown fragmental limestone. Sandstone and sandy limestone beds are present in the member in some of the exposures up the Christina River. This suggests a local uplift of Precambrian rocks in the nearby area shedding coarse clastics in Christina time."

"Where complete, the thickness of the Christina Member varies from 23 m in the Bear Rodeo No. 1 well to about 37 m in the Bear Rodeo No. 2 well."

"The lithology of the Moberly Member in outcrops consists of an alternating succession of light olive green, rubbly, thinly-interbedded, variably argillaceous limestone and shales, and even, hard beds of pale brown, aphanitic, fragmental limestone. The member becomes more shaly towards the top, and shale content appears to increase also from south to north."

In the Bear Biltmore No. 1 Well where the member is complete it is 60 m thick."

"The Mildred Member is 43 m thick in the type well (Bear Biltmore No. 1) and consists fo greenish grey calcareous shale, greenish grey argillaceous limestone, and some pale brown aphanitic, clastic limestone." The Mildred Member has been removed by erosion within the study area.

The Waterways Formation is stated to be generally not permeable except where fractured (Gorrell, 1974). Local fracturing by collapse due to solution of underlying salt beds has been postulated by many authors.

The Waterways Formation forms the Devonian Erosional Surface over the entire study area. The erosional surface is a very important feature both hydrogeologically and in controlling distribution of water sands and possibly oil saturation within the McMurray Formation. Knowledge of the character of this surface and of associated sediments is a necessity in order to make adequate predictions as to its impact on groundwater movement, both natural and induced.

Carrigy and McLaws, (1973) indicate that near Bitumount, a large collapse structure covering an area of over 130 km^2 has resulted in overlying beds dropping many tens of meters. Hackbarth and Nastasa, (1979) have postulated similar large structures within the study area in the vicinity of their postulated Sewetakun fault. Carrigy and McLaws (1973) state that there are "many hundreds" of small, circular sinkholes less than 30 m in diameter on the Devonian surface which have been infilled with rubble. They state that the role of the sinkholes in the regional groundwater flow system is "as yet unknown and needs to be investigated." Most authors, including Carrigy and McLaws, attach considerable significance to these sinkhole areas as forming possible conduits for the upward movement of saline groundwaters from formations below the Prairie Evaporite Formation. Linear depressions on the Devonian surface caused by solution of underlying salt have been identified at many locations and mapped by Hackbarth and Nastasa, (1979) along the Sewetakun fault.

2.1.3 Mesozoic Rocks

2.1.3.1 McMurray Formation

The McMurray Formation is the bitumen-bearing unit in this area, and because of its economic importance has received considerable detailed study. Among the authors who have discussed the character of this formation within the area of study are Carrigy (1959, 1967, 1971, 1973), Gorrell (1974), Mossop (1976, 1978), Benthin and Orgnero (1977), MacCallum (1977), Stewart and MacCallum (1978), and Nelson and Glaister (1978).

Most workers in all areas have divided this formation into three basic units termed the lower, middle, and upper units. Carrigy, (1973) has added a fourth, generally thin, basal, pre-McMurray (?) unit which is not everywhere present. Interpretations of depositional environments vary from author to author and from one area to another, but in general the basal unit represents fluviatile river channel and paludal swamp deposits within depressions on the Devonian surface and can include paleosols and coarse detrital materials. The lower unit has been shown by most authors to be fluvial and is generally the coarser grained (usually fine to medium grained, occasionally coarser) and usually contains the richest oil impregnation. Grain size usually decreases upwards within the McMurray Formation and impregnations can occur anywhere within the formation.

Basal water-bearing sands are found in many places the McMurray Formation. These are usually thickest over topographic lows on the Devonian surface. Intra-McMurray water sands also occur, but are usually thin and discontinuous. In the eastern part of the study area, the McMurray Formation can be largely or entirely water-bearing in some places. Benthin and Orgnero (1977) state that in the Gregoire Lake area, the locations for in situ testing were chosen to be west of the water-bearing area, but as far east as possible to take advantage of the thickening sands in this direction. An approximate eastern limit of oil impregnation of the McMurray Formation has been recognized along the Clearwater River by Carrigy (1959a), and as shown on Figure 2-3.

MacCallum (1977) states that the McMurray Formation sediments are characteristically undercompacted and that porosity and permeability in the sand units can be "very high".

2.1.3.2 Clearwater Formation

The Clearwater Formation consists predominantly of grey marine shale. The formation includes laminated siltstone and fine-grained dirty sandstone units. It contains large crystals of gypsum on many outcrop faces. A thin bed of glauconitic sandstone, commonly very dirty, marks the base of the formation. This bed is termed the Wabaskaw Member, and is not everywhere present.

2.1.3.3 Grand Rapids Formation

The Grand Rapids Formation consists predominantly of thick-bedded "salt and pepper" sandstones, usually loosely consolidated, with shale interbeds. Water source wells have been drilled into this formation at the AMOCO Gregoire Lake site. Carrigy (1973) reports that small contact springs form the Grand Rapids - Clearwater contact are a common occurrence. The combined action of such springs has produced a terrace of varying width at the top of the Clearwater Formation along the Clearwater River valley downstream of Christina River.

2.1.3.4 Joli Fou and Pelican Formations

The Joli Fou Formation consists of dark grey marine shale which overlies the Grand Rapids Formation. It is 33.5 m thick and its type section near Joli Fou Rapids in tp 81-rge17-W4, on the Athabasca River.

The Pelican Formation consists of lenticular fine-grained quartzose marine sands and siltstones which outcrop along the Athabasca River upstream from Ft. McMurray. The nature of this formation is poorly known in the subsurface of the study area.

Within the study area, the Joli Fou and Pelican Formations are present only in the Stony Mountain Upland and in the southern part of the Algar Plain.

2.1.3.5 La Biche Formation

The La Biche Formation is present in the study area only in the Stony Mountain Upland and in the southern part of the Algar Plain. It consists of dark grey marine shale and silty shale.

2.1.4 Pleistocene and Recent Deposits

Bayrock and Reimchen (1974) have mapped the surficial geology of the area. They show that till in the form of hummocky and ground moraine underlies most of the Stony Mountain Upland and parts of the adjoining plains on the east and west, while glacio-lacustrine clays and silts are predominant to the north of the Stony Mountain Upland. Aeolain sand is mapped in a small area adjoining Christina River on the east. Recent alluvium floors the major river valleys.

Green, etal (1970) have outlined areas of thick drift within the study area, and state that the drift cover can be up to 180 m thick under much of the Stony Mountain Upland.

Ozoray (1974) has shown structure contours on the base of the drift interval. He shows, on the basis of limited data, three major buried valleys on the bedrock surface.

1) a southeasterly trending valley extending from Gregoire Lake to tp 84, rges 4 and 5W4 which then turns northward to run between Gordon Lake (in tps 86 and 87-rges 3 and 4-W4) and Christina River.

2) a narrow northeasterly trending valley starting at tp 84, rge 11, W4.

3) a northwest-southeast trending valley running from tp 84, rge 11, W4 to tps 81 and 82 rges 6 and 7W4.

From Ozoray's work, it would appear that drift thickness along the first mentioned valley trend is in the order of 60 m near Gregoire Lake and about 90 m in tp 84-rge 5-°W4 and in tp 86-rge 5-W4. Drift thickness along the second mentioned narrow valley does not

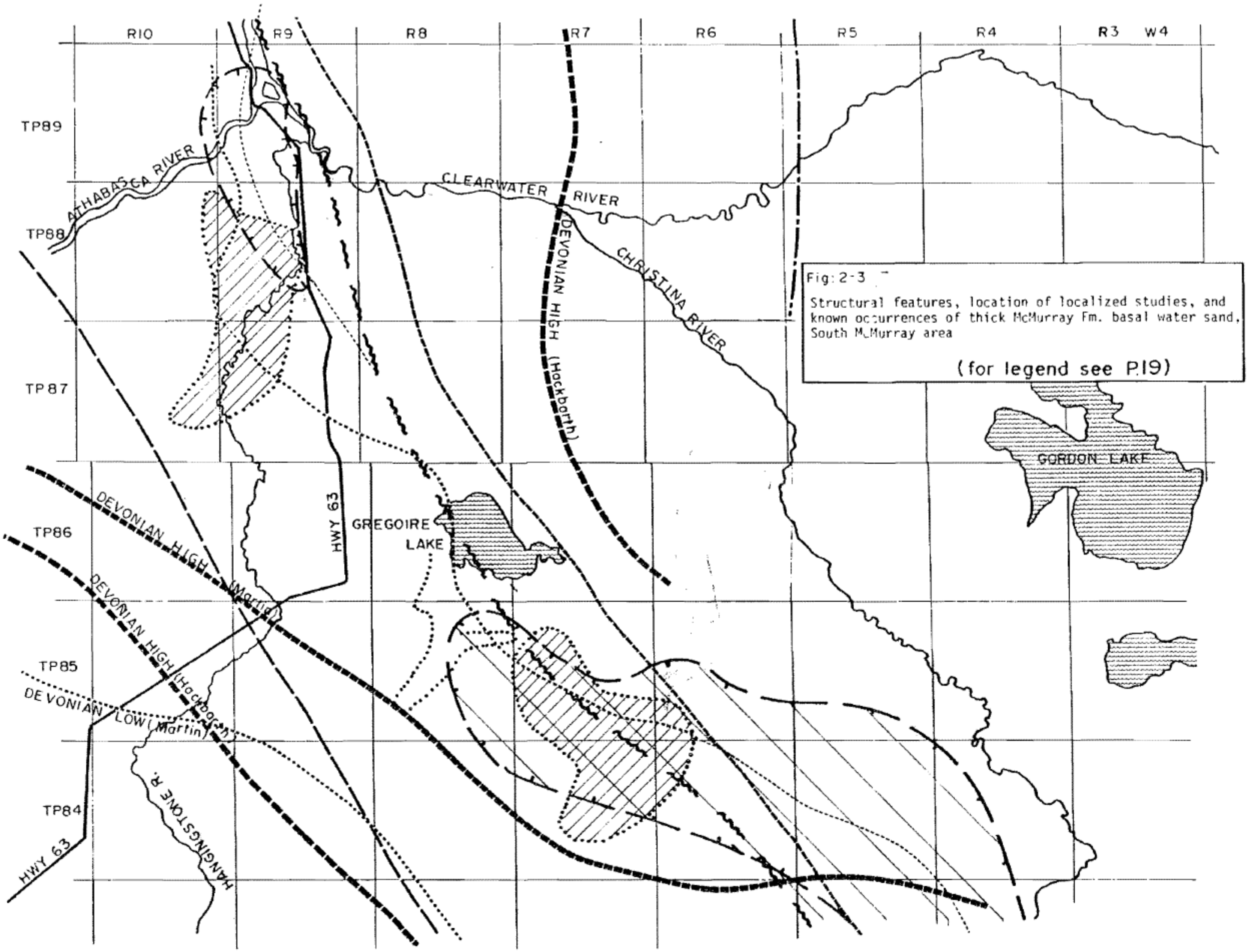
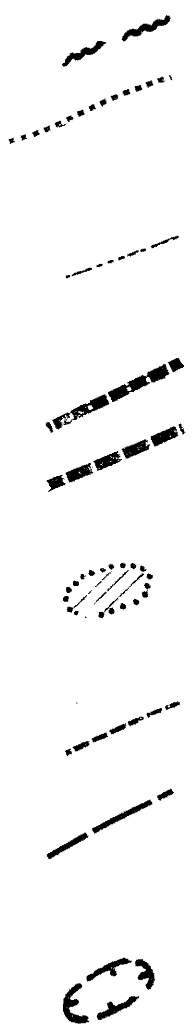


Fig: 2-3

Structural features, location of localized studies, and known occurrences of thick McMurray Fm. basal water sand, South McMurray area

(for legend see P.19)

LEGEND FOR FIGURE 2-3



Postulated Sewetakun Fault (after Hackbarth & Nastasa, 1979)

Low on Devonian surface and inferred direction of gradient (after Martin & Jamin, 1963, ERCB, 1963)

As above, after Hackbarth and Nastasa, 1979

High on Devonian surface (after Martin & Jamin, 1963)

As above (after Hackbarth and Nastasa, 1979)

Known extent of basal McMurray aquifer over 100 meters thick (in part after Hackbarth & Nastasa, 1979)

Approximate eastern zero edge of salt in Prairie Evaporite Fm. (after Hfamilton, 1971)

Closed depression on Prairie Evaporite surface (after Hackbarth and Nastasa, 1979)

Approximate eastern limit of oil saturation in McMurray Fm. (Fm. is clean sand, water bearing, east of this line) appear to be much in excess of 30 m. Drift thickness along the last mentioned valley which trends across the Stony Mountain Upland can exceed 180 m in places. Even in the highest parts of the upland in tps 84 and 85-rges 8 and 9-W4, drift thickness according to Ozoray, is still in the order of 120 to 180 m.

Sand and gravel beds within the drift can form excellent aquifers. These are usually thickest within buried valleys. Some of the sands and gravels in the lowest parts of these valleys as well as older terrace gravels on the valley sides may be preglacial in age.

McPherson and Kathol, (1977) have carried out a preliminary but fairly detailed study of the surficial geology in an area north of Fort McMurray which included the drilling of 275 testholes to a maximum depth of 44 m. A similar study in the area under investigation would be useful in identifying areas of thick drift, and major drift aquifers which might be affected by in situ operations.

2.2 STRUCTURE

A major fault affecting the Precambrian and younger strata just east of the Weymarn #1 well in sec. 16-89-3W4 was first postulated by Sproule, (1938) and further discussed by Kidd, (1951) and Carrigy, (1959a). A vertical downthrow of 60 meters on the west block is reported. Norris, (1973) suggests that the fault may trend N 35 degrees west. Kidd, (1951) presents evidence that movement took place in post-Clearwater Formation time.

Martin and Jamin, (1963) indicate a major northeast-southwest trending fault, which is also mentioned by Stewart, (1963). This fault lies considerably to the west of the study area. Martin and Jamin state that many additional faults are present which affect only the Paleozoic and Precambrian strata, and most of which strike northeast.

Stewart, (1963) states that deep-seated structures, apparently the result of block faulting in the Precambrian basement, reflect as ridges on the pre-Cretaceous unconformity surface and cites an example near section 6-89-5W4 which is outside the study area. He states that although direct evidence is lacking, these ridges are probably caused by faulting of underlying Precambrian rocks. Gorrell, (1974) suggests that some of the interpretations of very long fault systems could in fact be explained by salt solution.

Hackbarth and Nastasa, (1979) postulate a major fault, which they call the Sewetakun Fault, crossing the study area from near Fort McMurray in the northwest and trending southeasterly to a point in Tp. 81, Rge 2W4. This postulated fault, according to those authors has had strong controls on the valley system developed on the Palaeozoic surface and on groundwater movement in the area.

3.0 HYDROGEOLOGY

Ozoray (1974) mapped the hydrogeology of the Waterways - Winefred Lake area, Alberta (N.T.S. map sheets 73M and 74D), which included the present study area. His report presented maps showing:

a) basic geology including structure contours on selected formations,

b) meteorology,

c) predicted long-term well yields showing selected data control points and spring locations,

d) hydrochemistry of drift and bedrock, and

e) four cross-sections extending from land surface down to the upper part of the Devonian interval. Parts of 3 of these cross-sections extend across the present study area.

Gorrell (1974) co-ordinated a regional hydrogeological study in the McMurray Oil Sands area for the Oil Sands Environmental Study Group (OSESG) which is an organization of 23 leaseholders, development and operating companies. This report discussed groundwater flow systems and groundwater terminology in general terms, summarized the available hydrogeological data in the area, and discussed the geology, hydrogeology and hydrochemistry of the area. The possible effects of groundwater flow systems on oil recovery operations and vice versa were discussed. Possible environmental effects were also noted.

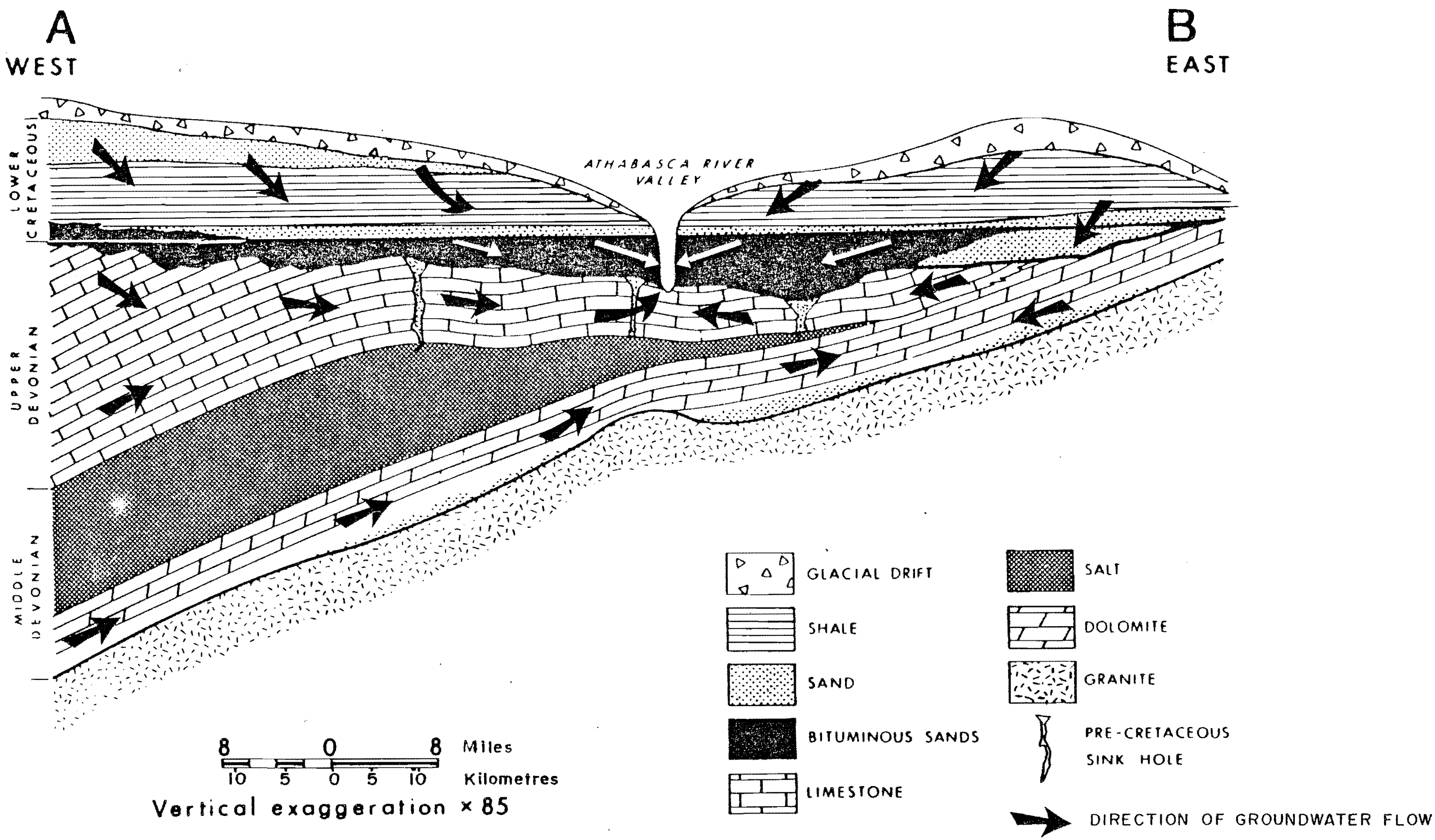
A regional network of groundwater observation wells was undertaken in 1974 by the Groundwater Division of The Alberta Research Council. This involved the installation over the following three years of several piezometer nests down to depths of 485 m. Piezometers were installed in all important water-bearing formations down to the Precambrian surface. Three piezometer nests, none of which has tested the stratigraphic intervals below the Prairie Evaporite, are located within the study area. Hackbarth (1978b) and Hackbarth and Nastasa (1979) has summarized the results of this study. Basic data is presented by Hackbarth, (1976, 1977).

3.1 GROUNDWATER FLOW

Carrigy and McLaws (1973) have commented on the possible effects of in situ operations on groundwater. They indicate regional groundwater flow to be approximately as shown in Figure 3-1. They have commented that one of the most important features dominating the groundwater flow pattern is the dissolution of Elk Point salt by fresh-water flow, which has resulted in collapse structures and undulations in the overlying limestones. They state that the role of collapse structures (sinkholes) in the regional groundwater flow system is as yet unknown and needs investigation. Gorrell (1974) has indicated some possible effects of salt solution on groundwater systems (Figure 3-2).

Hackbarth and Nastasa (1979) based on hydraulic head distribution at the three Alberta Research Council observation wells located within the study area, have indicated possible groundwater flow directions as shown on Figure 3-3. They have noted generally low hydraulic heads in the Paleozoic Formations and attributed this to fracture permeability developed along the Sewetakun fault.

Groundwater movement is predominantly downward in formations above the Devonian, although there are dominantly horizontal flow components in the Grand Rapids Formation, in the McMurray Formation water sands, and in sand and gravel aquifers in the drift. Hackbarth and Nastasa, (1979) cite dominantly horizontal flow within the Waterways and Slave Point Formations, while hydraulic heads in the formations underlying the Prairie Evaporite Formation indicate upward movement. The Sewetakun fault zone would be expected to form a natural conduit for the upward movement of water from below the Prairie Evaporite Formation. Hackbarth and Nastasa, (1979) however, based on extremely limited control, indicate that the major focus of regional groundwater discharge may be farther to the northeast, northeast of the Christina River (or possibly along the Christina River). If so, then topographic effects may be exerting a stronger influence on groundwater movement than permeability distribution. Highly saline springs along the Clearwater River and possibly along



(after Carrigy, 1973)

SCHEMATIC DIAGRAM OF REGIONAL GROUNDWATER FLOW FIG. 3-1

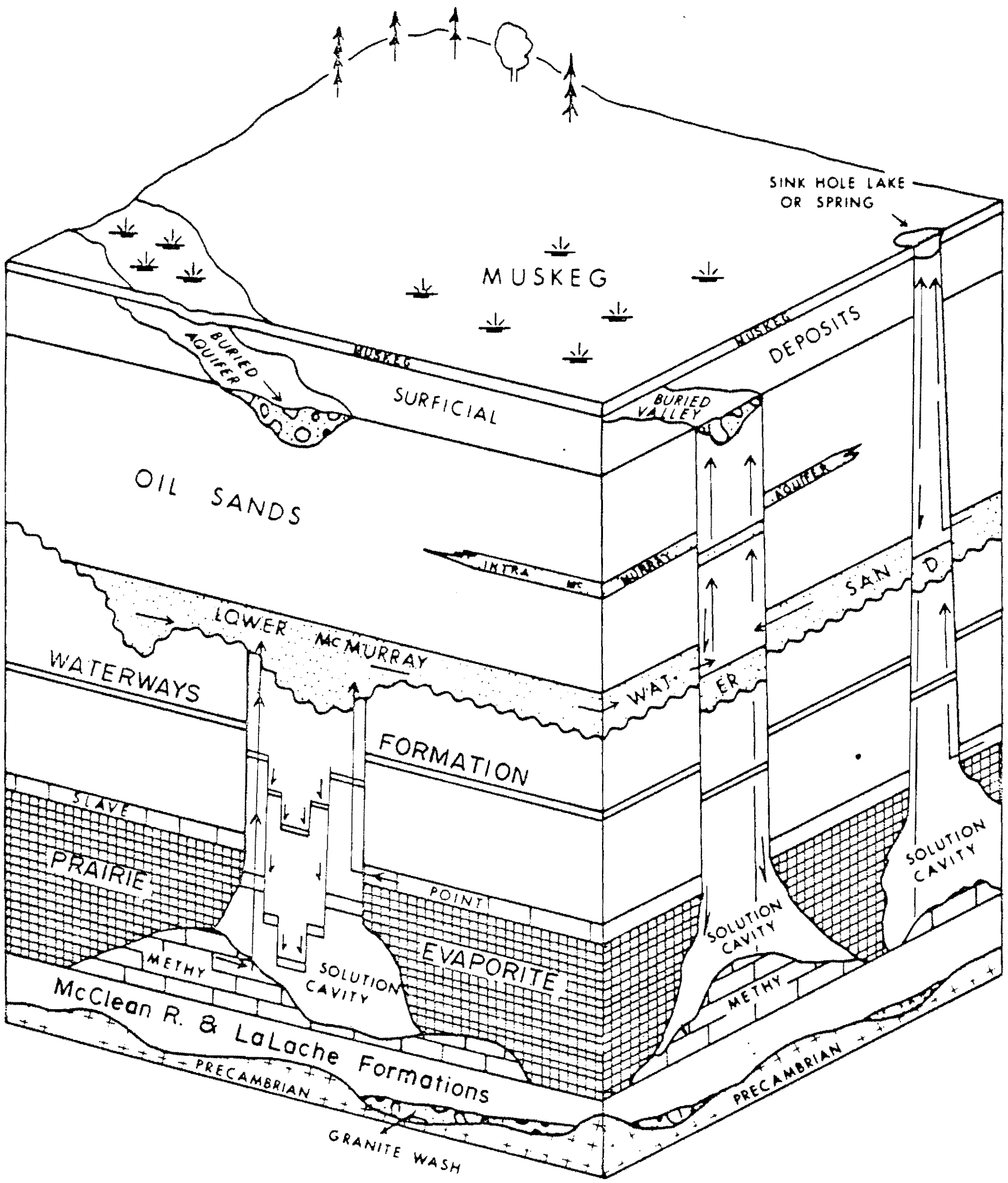
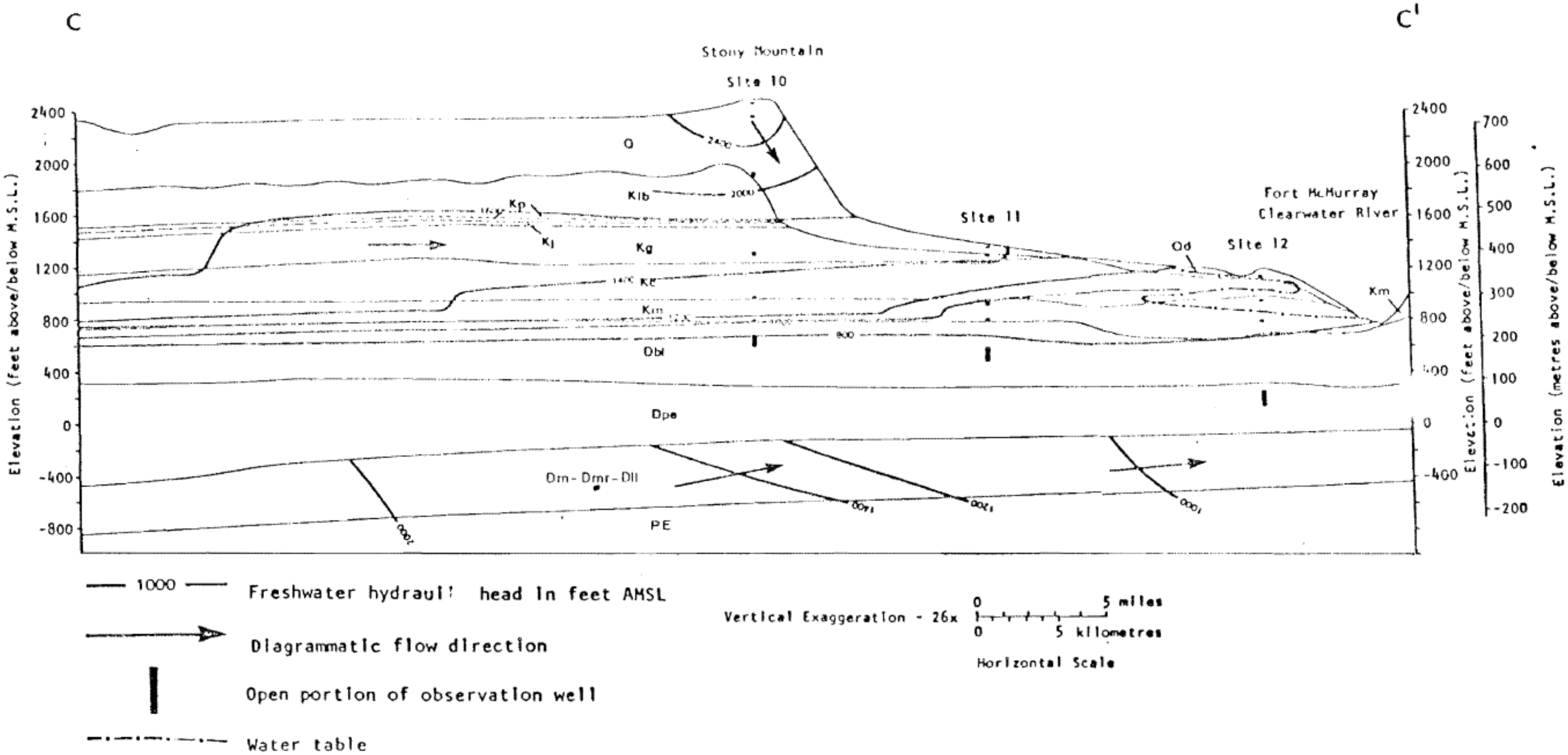


Figure 3-2 Sketch showing possible effects of salt solution on groundwater systems (not to scale)

from Gorrell, 1974 (modified)



Qd	Glacial drift
Ks	Smoky Group
Klb	Labiche Formation
Kd	Dunvegan Formation
Ksh	Shaftesbury Formation
Kpl	Pelican Formation
Kj	Joli Fou Formation
Kg	Grand Rapids Formation
Kc	Clearwater Formation
Km	McMurray Formation
Dbl	Woodbend Group and Beaverhill Lake Formation
Dpe	Fort Vermilion, Watt Mountain, Muskeg, and Prairie Evaporite Formations
Dm	Methy, McLean River, and LaLoche Formations

Figure **3-3** Hydraulic heads & groundwater flow patterns, cross-section through Research Council wells south of Ft. McMurray

from Hackbarth & Nastasa, 1979

the Christina River are postulated to be, in the main, discharge points of groundwater from formations below the Prairie Evaporite Formation. The strongest springs may be indicative of reefal buildups in the underlying Methy Formation or of zones of higher permeability within the LaLoche Formation, as well as being an indication of possible conduits through the Prairie Evaporite Formation extending upwards to the land surface.

Gorrell, (1974) has dealt with theoretical aspects of groundwater flow systems and has discussed the steady-state flow systems existing under natural conditions and the local transient flow systems which will be set up around sites of in situ extraction and near waste injection wells. Among the changes to the natural steady-state systems, he cites altered fluid pressures and hydraulic heads, which can, in many instances, change the direction of groundwater movement. Other effects include changes in water temperature and chemistry, piping to the surface, deformation of earth materials, blowouts, possible earth tremors, changes in volume of discharging groundwaters, and changes in permeability of materials. Prediction of the magnitude and extent of the possible effects is very difficult, but is made easier by the accumulation of pertinent hydrogeological data obtained by adequate testing, sampling, monitoring and reporting. Piping and blowouts are known to have occurred on at least one occasion within the study area.

3.2 GROUNDWATER CHEMISTRY

Groundwater chemistry has been discussed by Gorrell, (1974) and Hackbarth and Nastasa, (1979). The latter authors state that topographic features such as Stony Mountain have a major influence on both groundwater flow (strong vertical gradients) and on groundwater chemistry. Waters are therefore relatively fresh within the Quaternary strata and in the Cretaceous formations overlying the McMurray Formation in the upland areas. Total dissolved solids and chloride content are higher within the McMurray Formation. A range of about 3,000 to 10,000 mg/l and about 900 to 5,000 mg/l for total dissolved solids and chloride, respectively, in intra-McMurray aquifers within the study area has been mapped by Hackbarth and Nastasa. Higher mineralization is observed locally in basal sand aquifers e.g. total dissolved solids 15,588 mg/l and chloride 9,800 mg/l in the Research Council observation well #11. Samples of produced water from the Amoco site show total dissolved solids of 8,110 to 10,300 mg/l and chloride concentrations of 3,350 to 4,220 mg/l (Carrigy and McLaws, 1973, Lombard - North, 1974).

Hackbarth and Nastasa, (1979) report a significant difference in chemistry in waters from the Waterways Formation and those from the Prairie Evaporite and older formations. They show that concentrations within the study area for the latter formations range from about 200,000 to over 300,000 mg/l total dissolved solids and from 100,000 to 200,000 mg/l chloride. The ranges obtained for the Waterways Formation in Research Council observation wells 10 and 11 are about 12,000 to 18,000 mg/l and 6,000 to 11,000 mg/l for total dissolved solids and chloride respectively. Hackbarth and Nastasa state that the relatively low mineralization of water in the Waterways Formation suggests that significant upward flow of water from the Prairie Evaporite Formation does not occur. This may be true of the two sampling locations, but locally much more highly mineralized water may be found, as is the case near Bitumount, north of the study area (see also previous discussion in section 2.1.2.6).

3.3 NATURAL GROUNDWATER-RELATED FEATURES

The most obvious features of groundwater discharge are springs and seepages. Saline and mineralized springs have been noted by many workers along the Clearwater River, notably by Bell, (1884), McConnell, (1893), Carrigy, (1959a), and Ozoray, (1974). The source of the salinity and mineralization may be attributed in large part to solution of salt from the Prairie Evaporite Formation, as well as to "natural" salinity of waters (connate waters) derived from the LaLoche and Methy Formations.

Dusseault, (1977a) has commented on smaller springs and seepage areas along the Athabasca and Clearwater Rivers and their tributaries. He has noted that rich oil sand forms a barrier to groundwater flow and has described spring lines both above and below oil-bearing sands. These are gravity-induced contact springs and seepages. Amoco (1977) have indicated approximate spring zone locations along the Clearwater River.

Reported spring and seepage zones are shown on Figure 3-4. Additional features which may indicate possible groundwater discharge have been located by a study of aerial photographs. Ground checking is necessary to prove their exact nature.

Natural spring and seepage zones should be better delineated as to location and extent and flow rates and water chemistry should be determined. This will provide valuable background data as to natural conditions prior to the operation of major in situ projects and should form part of any monitoring system. Monitoring should be carried out on a periodic basis before, during and after the operations of in situ projects.

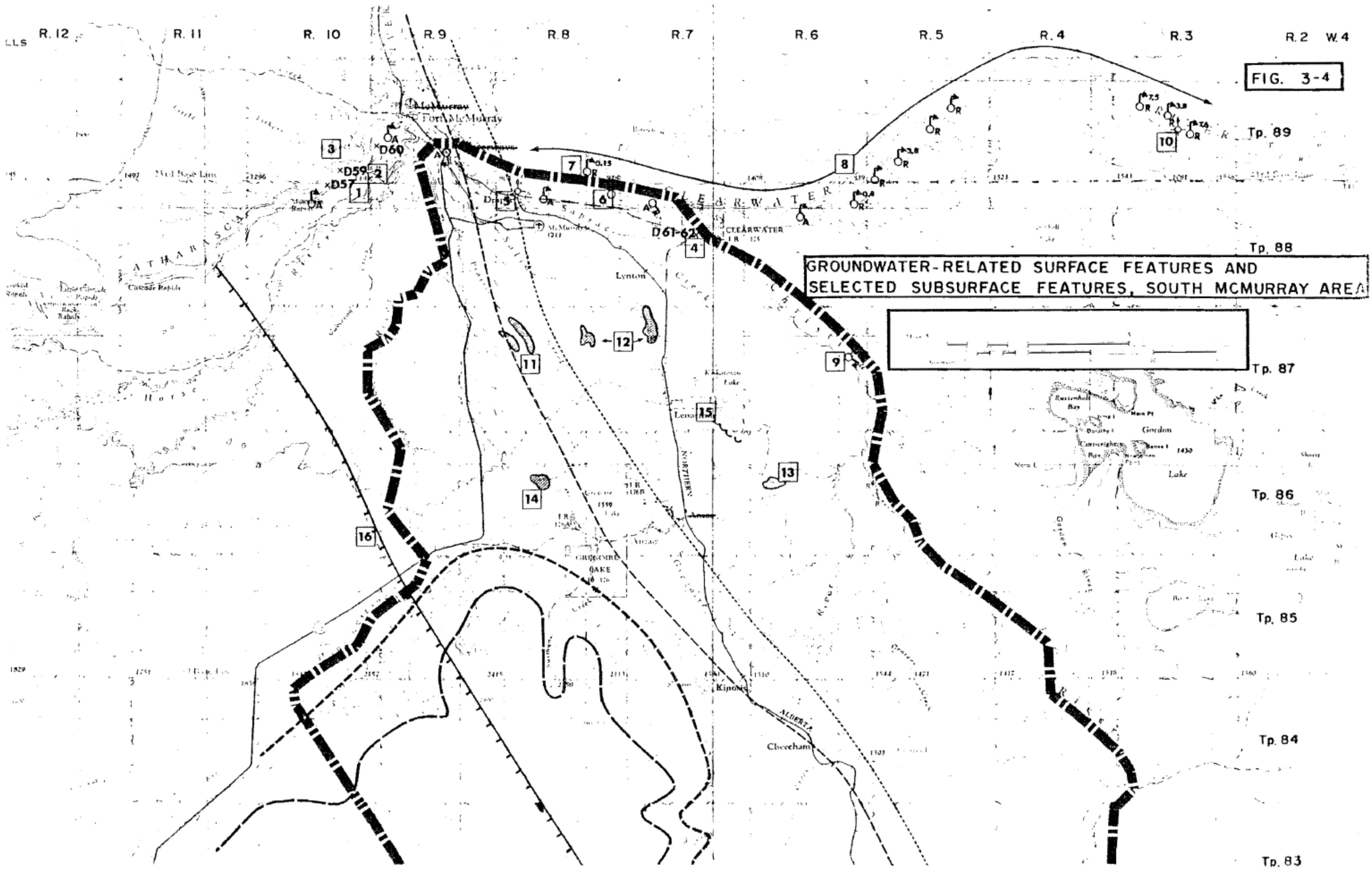


FIG. 3-4
GROUNDWATER-RELATED SURFACE FEATURES AND SELECTED SUBSURFACE FEATURES, SOUTH McMURRAY AREA
R.12
R.11
R.10
R.9
R.8
R.7
R.6
R.5
R.4
R.3
R.2 W.4
Tp. 89
Tp. 88
Tp. 87
Tp. 86
Tp. 85
Tp. 84
Tp. 83
Fort McMurray
CLEARWATER
ATHABASCA
D60
D59
D57
D61-62
Lynton
Gordon
Lake
Cheecham
Kinosis
ALBERTA
NORTHERN
GREGOIRE LAKE
Cascade Rapids
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16

KEY TO FEATURES SHOWN IN FIGURE 3-4

(1) D57 - no seeps or springs
(2) D59 - seepage lines from basal Clearwater Formation
(3) D60 - as above
(4) D61 - seeps at basal Clearwater Formation, and from intra-McMurray and basal McMurray sands
(5) Alberta Government Salt Well #2 - flowed salt water at
(6) Bear Westmount #2 - water in Methy dol. at 190.5 meters, gas at 161.5 meters
(7) Spring in 3-2-89-8W4 flowing at 0.15 l/s., total dissolved solids 10,124 mg/l
(8) Line of cold mineral springs along Clearwater River (Bell, 1881, Carrigy, 1959a), salt at 3000-20,000 ppm, mainly Na Cl; calcareous deposits and smell of H_2S; temperature 4 to 6.5 degrees C
(9) Approx. location of saline springs (McConnell, 1893)
(10) Weymarn #1 well - flowed water from LaLoche Fm. at 147.8m
(11) Wet open areas and creeping fen, possible collapse feature (?)
(12) Open meadows (saline D?), possible collapse feature (?)
(13) Open meadow, possible collapse feature (?)
(14) Wet open area, possible collapse feature (?)
(15) Line of springs and seeps (?)
(16) Salt thins rapidly east of this line (area of active salt solution?) and increases in thickness only very slowly to the west.

4.0 PILOT PLANTS

The locations of the experimental test sites and the ownership of the other leases in the study area are shown in Figure 4-1.

Geological cross sections have been prepared through the areas of the three pilot plants and through the Alberta Research Council's observation wells. The locations of these cross sections are shown in Figure 4-2.

Figure 4-3 is a geological cross section through the three Research Council observation well sites. The other geological cross sections are drawn through the pilot plant sites and will be referred to in conjunction with the discussion on each plant site, which is in the appendices.

4.1 IN SITU PROCESS

Several factors make the Alberta oil sands different from conventional crude oil deposits. The bitumen itself is many times more viscous than conventional crude oil, and for all practical purposes it may be considered immobile. The viscosity is in excess of 10^6 centipoises and , as it occupies nearly all of the void space in the reservoir, may be regarded as mainly impermeable under natural conditions. In addition to this, the reservoir energy is very low. Thus, a significant reduction in viscosity and a driving force are necessary to move the bitumen.

In addition to this, the reservoir geology changes rapidly both vertically and horizontally over extremely short distances. (In the order of metres vertically and tens of metres horizontally). These conditions make correlation between test holes very difficult. Communication between even closely spaced wells may also be difficult for these same reasons.

Redford, (1976) has classified the recovery methods into two classes; the first transforms the bitumen into a less viscous form, allowing recovery by displacement. An example of this method is the forward combustion process.

OIL SANDS LEASES IN AND NEAR STUDY AREA

Approx. scale 1: 450,000

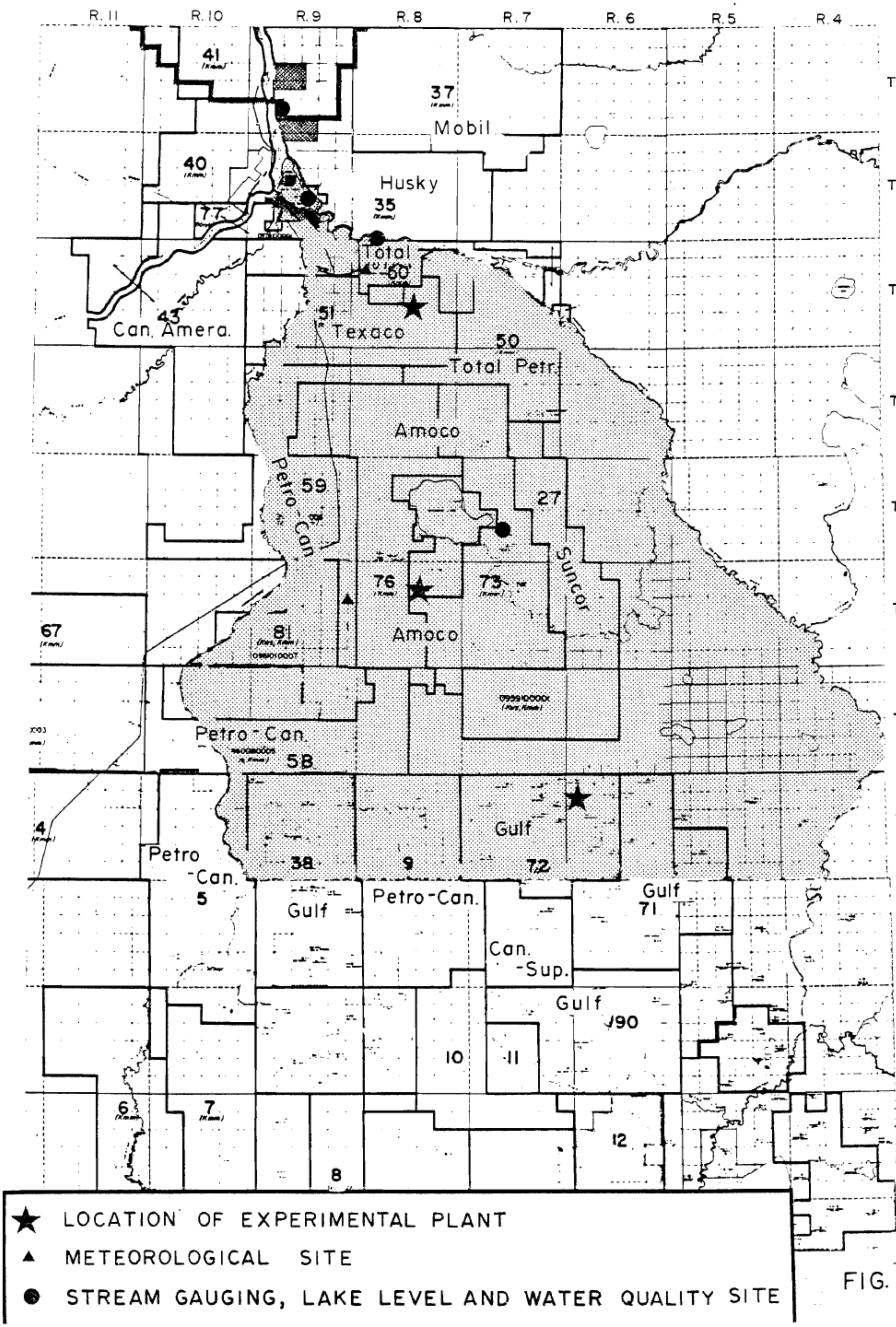


FIG. 4-1

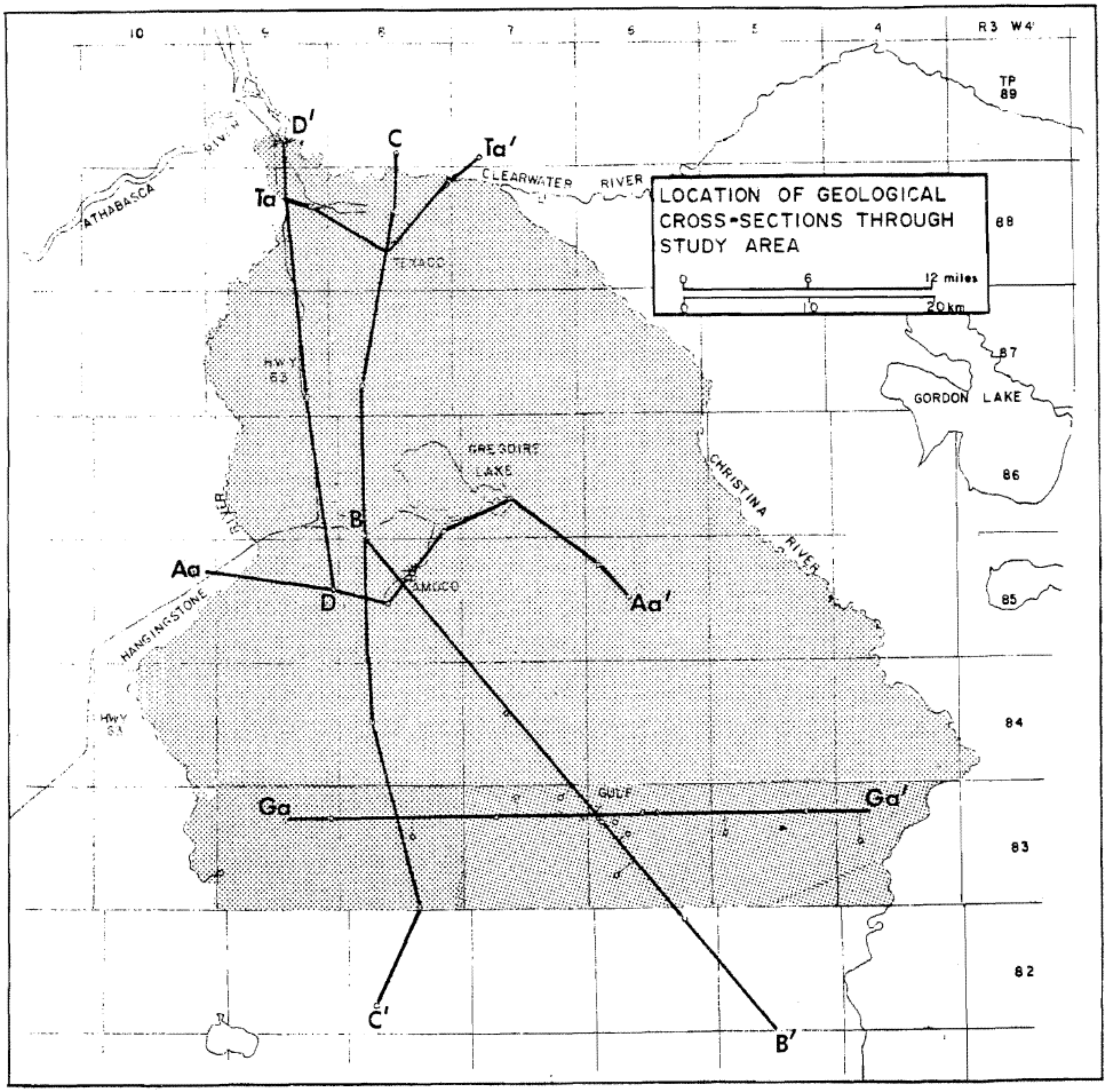

LOCATION OF GEOLOGICAL
CROSS-SECTIONS THROUGH
STUDY AREA
0 6 12 miles
0 10 20 km
ATHABASCA
CLEARWATER RIVER
TEXACO
HWY 63
GREGOIRE LAKE
CHRISTINA RIVER
AMOCO
HANGINGSTONE RIVER
GULF
GORDON LAKE
D'
C
Ta'
Ta
B
Aa
D
Aa'
Ga
Ga'
C'
B'
10
9
8
7
6
5
4
R3 W4
TP 89
88
87
86
85
84
83
82

FIG. 4-2

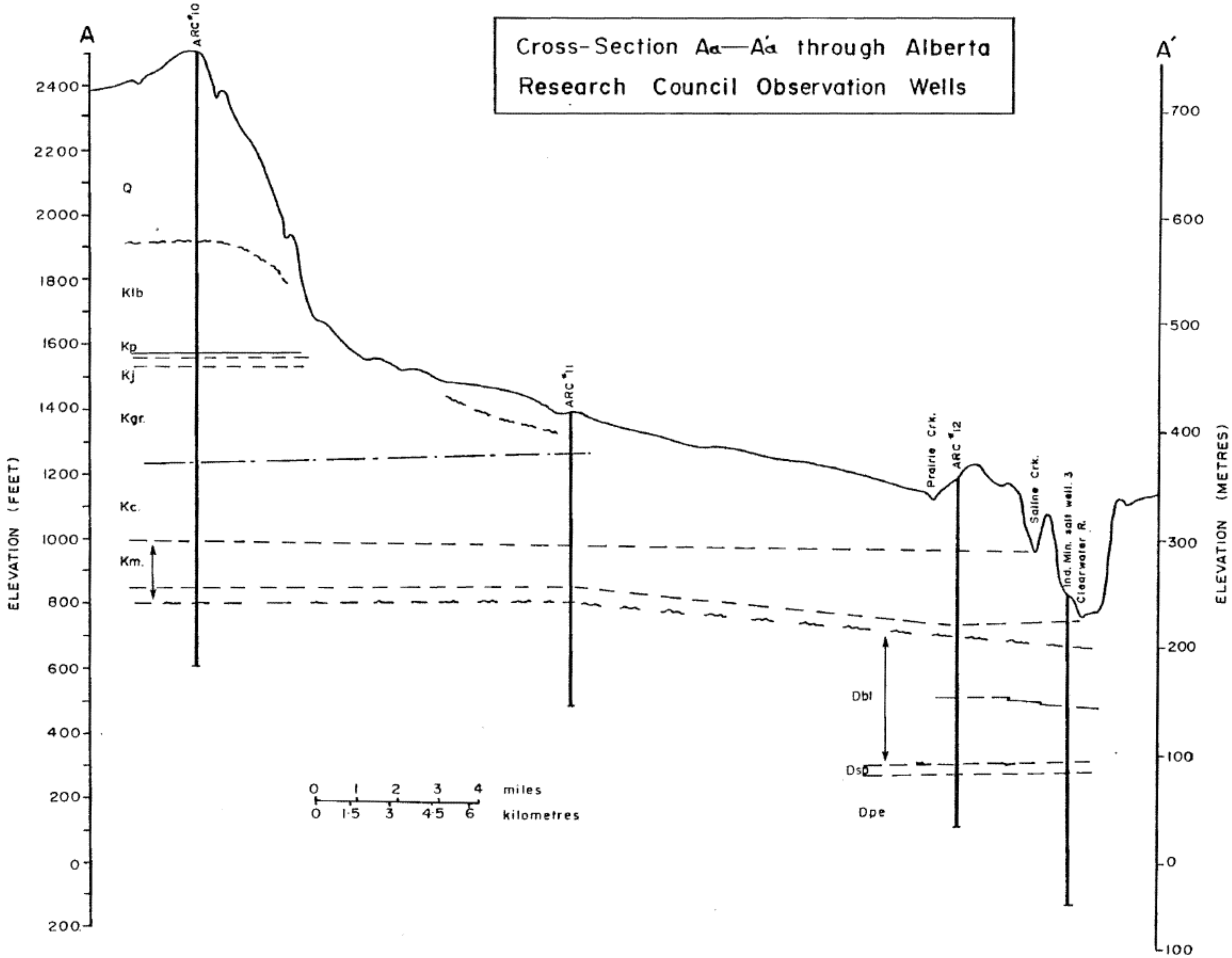

Cross-Section Aa—A'a through Alberta Research Council Observation Wells
A
A'
ARC#10
ARC#11
ARC#12
Prairie Crk.
Saline Crk.
Ind. Min. salt well. 3
Clearwater R.
Q
Klb
Kp
Kj
Kgr.
Kc.
Km.
Dbl
Dsp
Dpe
ELEVATION (FEET)
ELEVATION (METRES)
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
200
700
600
500
400
300
200
100
0
100
0 1 2 3 4 miles
0 1·5 3 4·5 6 kilometres

Fig. 4-3

The second class causes change and recovery simultaneously. Some of the bitumen is removed during each cycle, thus the heat or agents reach a fresh layer of bitumen each time. Vertical and horizontal steam stimulation are examples of this class.

The various in situ processes have been described by Carrigy and McLaws, (1973), Redford, (1976) and Hackbarth and Nastasa, (1979) and these authors should be referred to for further details. Steam injection is the process in use at the Texaco experimental site, and a modified combustion process, the combined forward combustion and water flood (COFCAW) process is in use at the Amoco site. In situ experiments at the Gulf site are in the beginning stages, but experiments in both single well steam stimulation (huff and puff method) and mine-assisted in situ processing (MAISP) are planned.

Various patterns may be used in the steam injection process. A 5-spot or 9-spot pattern are the most common, in which a central injection well is ringed by 4 or 8 producing wells, respectively, with a spacing of up to 150 meters between the producing wells in the case of a 5-spot pattern, a total area of up to 22,500 m^2 is required per injection site. The total time requirement from the beginning of steam injection to the end of production in a single pattern, which will result in the extraction of 50 to 70% of the bitumen in place, is approximately 3 1/2 years (Carrigy and McLaws, 1973). Effects on laterally adjacent, underlying, or overlying aquifers from a single pattern are therefore likely to be both localized and short lived. Full scale extraction will cover a much larger area and the cumulative effects on the groundwater system can be far-reaching and long-lasting. Careful monitoring of the steaming process should be carried out. Evidence of excessive steaming, or pressure losses would be indicative of escape of fluids to either adjacent aquifers directly or via natural or induced fractures, or to the surface by the same means.

The COFCAW process uses well patterns as mentioned above and oil production continues for about 5 1/2 years or until the burning front reaches the produciton wells (Carrigy and McLaws, 1973). Recovery of bitumen in place is stated to be 40 to 70% (Carrigy and

McLaws).

Formation fracturing to create initial flow paths is an essential part of successful in situ recovery. Dusseault, (1977) and others, have stated that hydraulic fracture planes are likely to be believed to exceed vertical stress at shallow depths. Settari and Raisbeck, (1979), point out that there is also the possibility of extensive inclined and vertical natural fractures (joints) in the oil sands as well as in overlying beds and that because of this, in addition to horizontal fracturing, inclined and vertical fractures may also be induced at shallow depths. This is shown schematically in figure 4-4. In addition, even horizontal fractures will tend to migrate upwards because of increasing natural fracture size and number in this direction. Settari and Raisbeck illustrated the influence of geology on fracture orientation, stating that they believe that in the depth range 335 to 600 m, fractures are more likely to be inclined or vertical, and use as an illustration the case of vertical fractures oriented generally in the north-east direction at the depth of 500 m at the Esso Resources Ethel Lake pilot project. Whether inclined or vertical, induced fractures will tend to be condinfed by overlying and underlying beds of lower permeability, because of higher horizontal stress level in these beds (Settari and Raisbeck, 1979). Basal shale and intra-formational shale beds within the McMurray Formation will therefore tend to confine any induced fractures. Settari and Raisbeck however also point out that "fractures may not be contained if there are not sufficient barriers in the adjacent layers".

Amoco has been working on the production of in situ oil sands since 1958. Their process can be broken down into 3 stages, which are:

1) Formation pre-heating is accomplished by injecting air into a central well, which results in dry forward combustion, which is propogated by fractures to surrounding producing wells.

2) Formation pressures are reduced or "blowndown" and the temperature moves to equilibrium across the entire heated section.

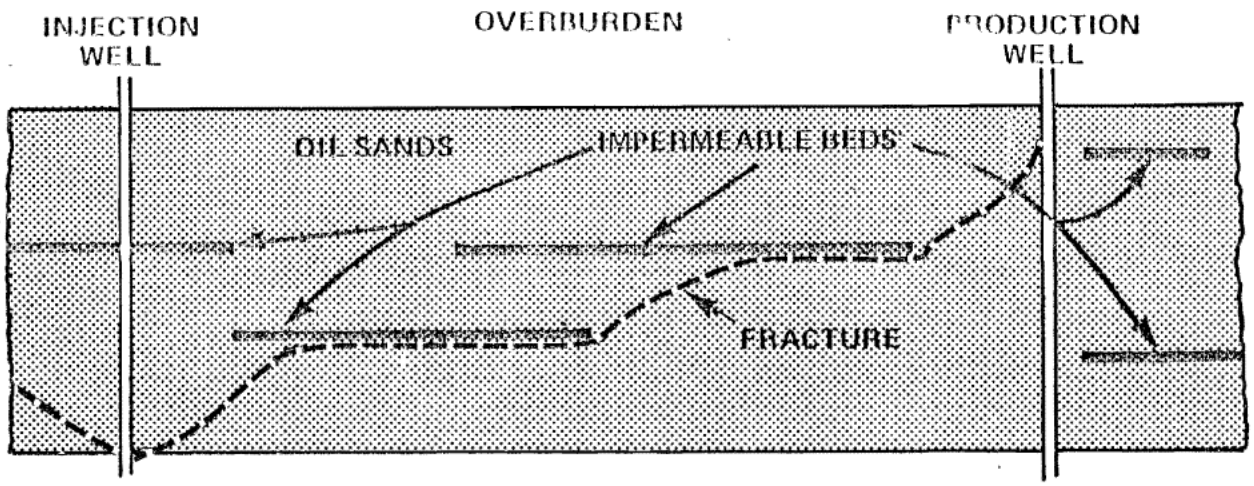


Figure 4-4. Schematic showing influence of geology on fracture orientation (from Raisbeck and Currie, 1979)

3) COFCAW displacement is the final phase of the process. Air injection is resumed which results in a combustion front moving outwards in the pay zone. Water is injected with the air, and this absorbs heat from the formation and transfers it as steam ahead of the combustion front.

This process if referred to as the COFCAW Process, which stands for Combination of Forward Combustion and Water Flooding.

Because of the high pressures required to induce fracturing, this process is limited to areas where there is a substantial (150 m) thickness of overburden. Up until 1977 there had been a 6-phase experimental program. Details of later experiments were not available at the time of preparing this report.

A multi-well test program was initiated in 1966 (Phases V and VI), with the latter field phase being initiated in 1970.

In 1966, a central injection well, and 4 producing wells were drilled (Figure 4-5). The central well was fractured using water and sand. The well was ignited and forward combustion was initiated by air injection at overburden pressures. The temperature in the well was controlled by injecting small amounts of water. The heating period lasted approximately 7 months, and heat breakthrough was made to all of the surrounding producers. Approximately 50 percent of the formation was heated to an average temperature of 65 degrees C. Figure 4-6 shows the horizontal and vertical isotherms after 7 months of heating. Temperatures ranged from 815 degrees C in the injection well to 38 degrees C just beyond the producing wells. The normal formation temperature is in the order of 10 degrees C.

These experiments resulted in heating up 53,000 barrels (8425 m^3) of the estimated 90,000 barrels - in - place (14,300 m^3), within the test well pattern. Some 30,000 barrels (4,800 m^3) were produced during a one year recovery period. The following table summarizes the results of the experiment.

	Amount	Percent
Estimated oil in place	90,000 barrels ($14,300\ m^3$)	100
Amount of oil burned	6,300 barrels ($1,000\ m^3$)	7
Amount heated to 65 C or higher	58,500 barrels ($9,300\ m^3$)	65
Amount produced	30,000 barrels ($4,770\ m^3$)	33

Most of the recovery was from 2 of the 4 wells. Amoco believes that the 33% production rate of oil-in-place can be increased to 50%. Well yields reached a maximum of 160 bbls/day ($25\ m^3$) with an average of more than 60 bbls/day ($9.5\ m^3$). It is believed that this average could be increased to 120 bbls/day ($19\ m^3$).

Amoco is confident that the COFCAW process can be used commercially and that a commercial in situ plant would have to have the capacity in the order of 100,000 barrels per day ($15,897\ m^3$) to achieve the economy of scale required to upgrade the bitumen for the market.

It has been indicated that such a project would be energy self sufficient after start-up. A central energy utility plant would utilize the coke by-product of up-grading for fuel, together with combustion vent gases. Such a plant would require 500,000 bbls ($79,500\ m^3$) of water daily, much of which would be re-cycled and 1,000,000,000 cubic feet of air ($28,320,000\ m^3$).

A well pattern would be set up on a 2 1/2 acre block (1 hectare) and over 25 years some 13,000 acres (5,261 ha) would be used. A total of some 10,500 wells will be drilled in this period, which will require some 25 drilling rigs working continuously for the whole 25 years.

At the time of preparing this report there are still technological problems to be overcome in well design and construction techniques. There are also major political hurdles to be overcome in order that the operations receive a satisfactory return on their investment.

In addition to these problems there is a major step from a pilot plant of 10 wells or less to a commercial plant of 10,000 wells.

Giguere, (1977) has shown the spread of heat in a multi-well injection test at the Amoco Gregoire Lake test site (Figure 4-6). The pattern suggests a northeast-southwest preferential direction to heat flow and a pronounced upward migration of heat to the northeast and southeast. Prior to ignition in this test case, fracturing was induced from the central well using water and coarse sand.

Carrigy and McLaws, (1973) have stated that under the present technology, overburden thickness should not be less than 150 m for safe and effective in situ operations. Overburden thicknesses are about 260 to over 300 m at the Amoco site, and over 270 m at the Gulf-Numac site, but can be as little as 75 m at the Texaco site (top of McMurray Formation). Nevertheless, experimental work has been carried on since before 1973 at the Texaco site, and at least one blow-out to the surface has been documented. In addition, this site is very close to the valleys of the Clearwater River and Saprae Creek. Due to its more sensitive location and the possibility of more direct effects to nearby surface water bodies, more careful scrutiny and monitoring at the Texaco site would be required. Furthermore, the oil sands at this location are reported to rest directly on Devonian carbonates, so that solution effects on the bedrock surface may be important. No major shallow aquifer, however, have been reported.

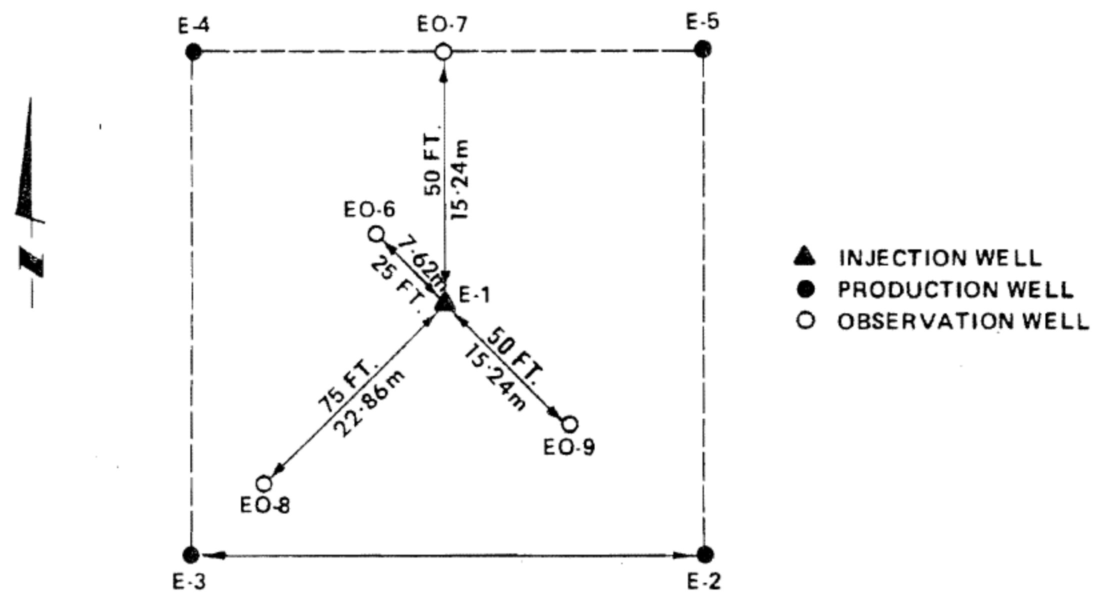
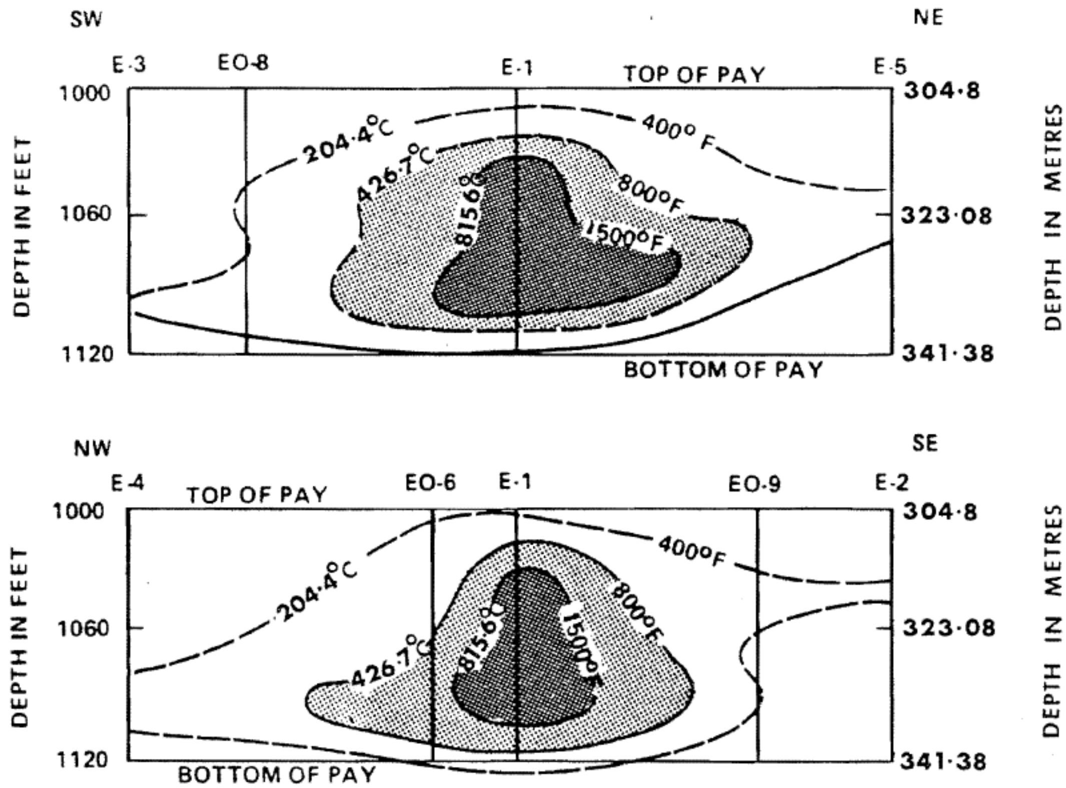
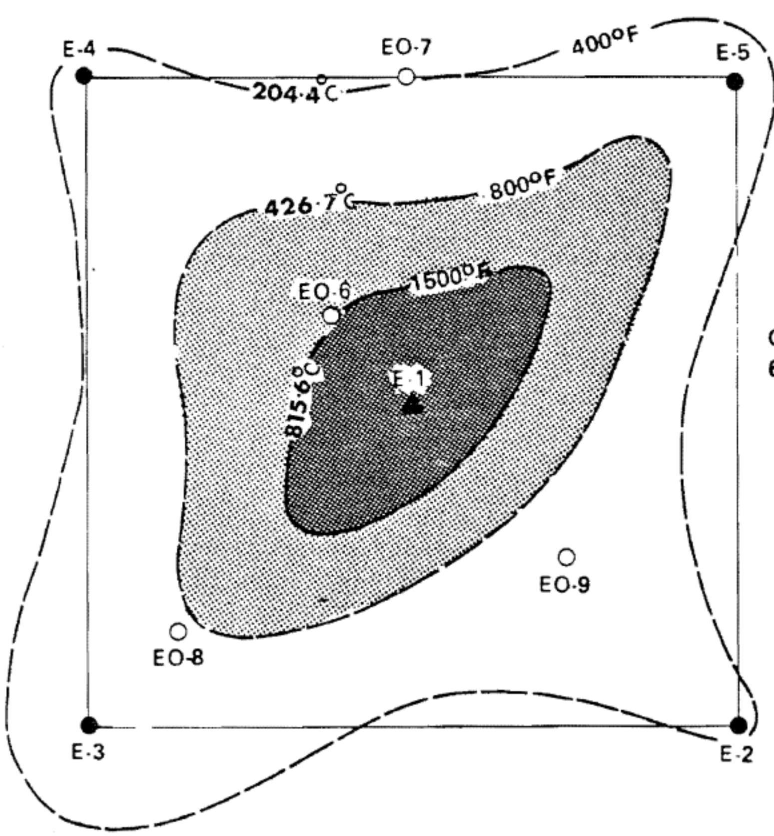


FIGURE No. 4 –5
PHASE V WELL PATTERN
AMOCO TEST SITE



VERTICAL ISOTHERMS



OIL IN PLACE 90,000 BBLS
65% OIL HEATED ABOVE 150° F

FIGURE No. 4-6
HORIZONTAL ISOTHERMS—AMOCO TEST SITE

5.0 ENVIRONMENTAL CONCERNS

5.1 GENERAL

Areas of impact on the groundwater regime may be divided into two categories:

1) indirect impacts
2) direct impacts

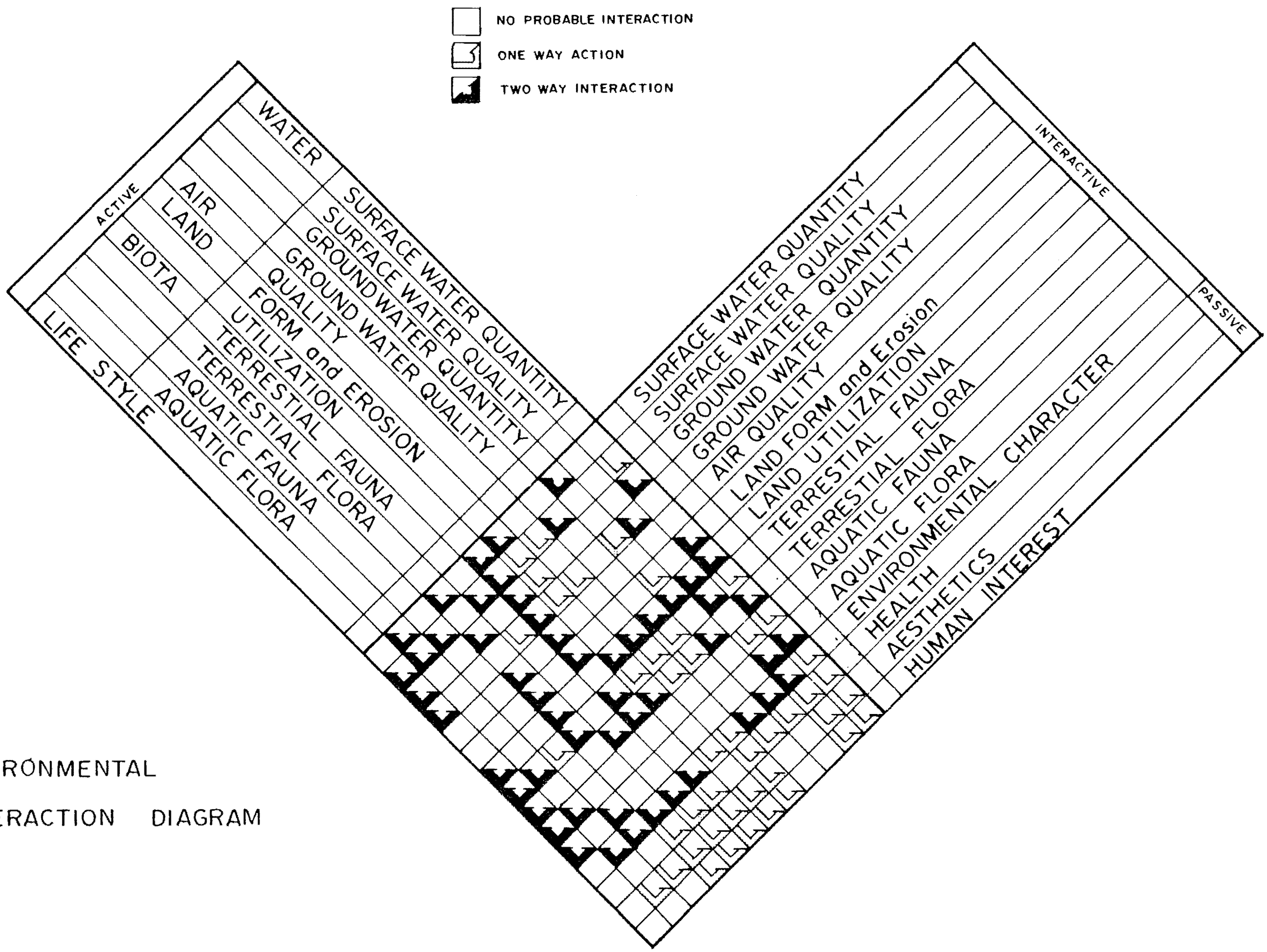
The indirect impacts result from changes in surface water which then in turn transmit this change to the groundwater via the recharge process. Figure 5-1 shows a schematic of the interaction process.

Changes in surface water quantity such as those brought about by draining muskeg could result in lower recharge rates to the groundwater system, thereby causing the water table to fall.

Changes in surface water quality are not expected to be major because of legislation covering the storage and disposal of waste materials. In addition to this most of the streams and rivers appear to have a net gain in groundwater inflow. i.e. groundwater discharges into the stream. There is, therefore, unlikely to be any major source of change in groundwater quality due to changes in river water quality.

One area of concern that is being expressed is the effects of acid rain which could increase the acidity of surface waters making them unsuitable as a habitat for fish. Such changes in surface water chemistry would be reflected in the groundwater chemistry, however, because of the high total dissolved solids and general poor-quality of groundwaters small changes in groundwater quality may be difficult to detect and may not be significant.

The best methods for monitoring indirect changes in groundwater levels and groundwater quality will be to monitor and control surface water runoff and surface water quality. Providing any changes in these parameters are kept within acceptable limits then the corresponding changes in groundwater should be considerably less.



ENVIRONMENTAL

INTERACTION DIAGRAM

Fig. 5 – 1

5.2 DIRECT CHANGES

Direct changes in the groundwater regime may be brought about during one of the following phases of plant development:

1) plant construction
2) development of a water supply
3) waste disposal
4) plant operation
5) long-term effects after project shut down

The most unique environmental impacts will be those resulting from the underground in situ extraction process. Here temperatures and pressures may be significantly altered; these, in turn, may also significantly change groundwater quality. The other significant feature will be the changes in permeability and porosity of the ore body due to fracturing and removal of the bitumen.

Apart from these areas many of the impacts will be similar to those created by other large construction and drilling projects.

5.2.1 Plant Construction

The main groundwater impacts during this phase will be felt in the shallower aquifers and in the muskeg. Clearing and draining of the muskeg will be less severe than that carried out in the surface mining operations. Guidelines established for these operations should be followed in muskeg removal and drainage.

With the large number of drilling rigs in operation one of the major concerns will be the clean-up of drilling mud pits. This is of particular importance because there will be in the order of 10,000 wells for each commercial plant. Disposal of the drilling fluid may create problems and further studies are required on this aspect.

There should be no major subsurface impacts providing that standard drilling practices are followed and satisfactory well completion methods are used. Poorly constructed wells could open paths of communication between different aquifers; however, if this occurrs it is unlikely that the well would function properly.

Plant site construction will have similar environmental impacts to other construction projects.

There is a possibility of oil spills although this would be more probable during the operating phase. The Prairie Petroleum Association- Marketing has done a considerable amount of work on the control and cleanup of oil spills. This technology would be readily available and this should not be a problem.

5.2.2 <u>Development Of A Water Supply</u>

Prior to the development of a water supply a permit has to be obtained from Alberta Environment.

If the source of water is surface water then there will be no direct impact on the groundwater regime, only indirect impacts, as mentioned earlier.

If a groundwater source is to be used then a Groundwater Exploration Permit must be obtained from the Controller of Water Resources, Alberta Environment.

Information required from the operator before a Permit is issued will be,

1) total volume of water required,
2) peak production rates,
3) aquifer(s) to be tested.

Conditions in the Permit will vary depending upon the volume of water to be used and the zones from which the water is to be taken.

A number of observation wells will be required and pumping tests will also be required. Once these tests have been completed a report will be required to obtain a Groundwater Abstraction Licence. This report should cover the local hydrogeology, pumping test data, water quality and predictions of the lowering of the water table around the producing wells.

It is believed that existing legislation and guidelines are adequate to evaluate and control the impact of developing a groundwater supply.

5.2.3 Waste Injection

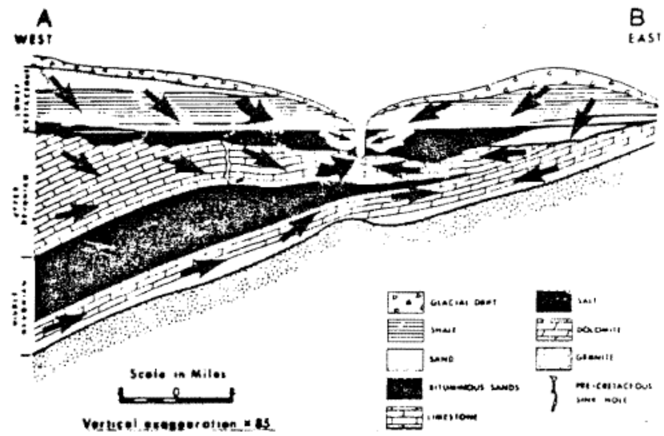
Deep well injection of liquid wastes in Canada has been in use since 1950. Up until 1978 there had been 74 deep well injection schemes and of these 20 were started in Alberta. The first scheme in Canada was carried out in 1950 at Lloydminster for the disposal of refinery waste products. Although there are a number of disposal schemes there is a lack of documented case histories and it is unlikely that detailed hydrogeological investigations have been carried out around these wells.

Van Everdingen (1971-1974) gives a good introduction to the problems of waste injection in Western Canada. Warner and Lehr (1977) give a comprehensive review of liquid waste injection practices in the United States.

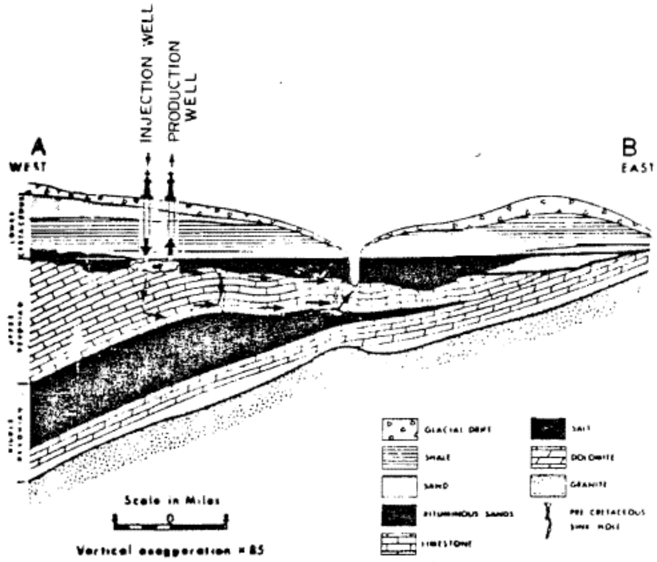
From these reports it is evident that injection well construction techniques are sufficiently well developed to ensure that injection of liquid wastes can be safely carried out. What is lacking is the knowledge of what happens to this liquid in the injection zone. "Computer programs exist, and are in common use, to predict hydraulic head changes due to liquid injection, models also exist to predict the movement and dispersion of wastes. However, what is lacking is an understanding of the chemical reactions which take place between the injected liquids, the formation and the natural formation water. Another major concern are the regional impacts of these practices. It is difficult for the operator to assess and monitor the impacts outside his lease boundaries.

What is necessary is a good network of monitoring wells that are completed in, below and above the injection zone. Because of the depth of injection, and the high cost, monitoring wells are rarely installed. For a large regional disposal operation there should be a sophisticated network of monitor wells. Injection and permeability tests should also be undertaken so that computer models can be used to predict the impact of liquid waste injection.

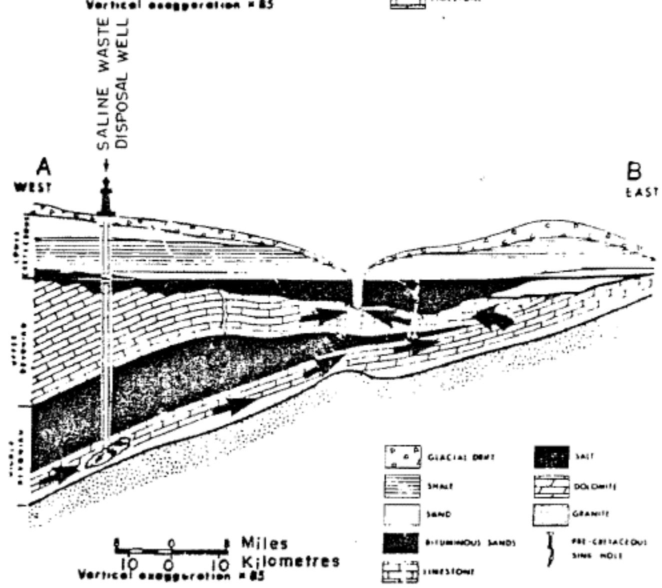
The cost of carrying out an adequate liquid waste injection



SCHEMATIC DIAGRAM OF REGIONAL GROUND-WATER FLOW



SOME POSSIBLE LEAKAGE PATHS FOR INJECTED FLUIDS



SUGGESTED LOCATION OF WELL FOR DISPOSAL OF SALINE WASTE

Natural flow pattern of saline formation water

HYDROGEOLOGICAL CROSS SECTIONS SHOWING GROUNDWATER FLOW AND POSSIBLE LEAKAGE PATHS FOR INJECTION FLUIDS.

FIG. **5-2**

investigation will be considerable. Regional injection facilities should be considered. One advantage of insisting on an adequate investigation will be to make sure that other methods of waste treatment are carefully evaluated and that only the most exotic wastes are disposed of through injection wells.

At the present time little is known about the nature of liquid wastes that may result from a commercial operation as much of the water will be re-used. Suspended solids will have to be removed in order to prevent clogging of the injection well. Most excess heat and injected solvents will have to be removed for the operations to remain viable. More information is required on the chemistry of the liquid wastes and on the volumes to be disposed of.

Within the area of interest, the Methy and LaLoche Formations provide the best zones for subsurface waste injection. Hackbarth and Nastasa (1979), however, have rated this area as being unsuitable for subsurface waste injection because of possible solution collapse features and faulting within the overlying Beaverhill Lake Formation. The faulting and collapse features could provide avenues for upward leakage of waste. The flow of natural salt springs could be increased, new springs created, and the chemical character of the spring outflows could change. Carrigy and McLaws, (1973) have shown possible leakage paths of liquid wastes. (Figure 5-2)

Rather than ruling out the entire area for waste injection, as do Hackbarth and Nastasa, (1979), Van Everdingen, (1976b) states that in areas of salt solution, injection could be allowed but should be restricted to formations below the Prairie Evaporite. He also points out that subsurface solution of salt may be actively continuing in some places at the present time. This could result in damage to surface installations and injection wells, and may increase opportunities for migration of injected waste to the surface (if injection is into zones above the Prairie Evaporite).

The Methy and LaLoche Formations appear to have sufficient permeability at least locally, to constitute potential zones for subsurface waste injection. The LaLoche Formation, however, because of rather limited thickness, may only be suitable for small amounts of waste. The overlying McLean River Formation should provide an effective confining bed. In those places where the salt within the Prairie Evaporite Formation has been leached, there may be vertical communication between the Methy and overlying units, and unless the hydraulic head in the Methy is low and remains low, the Methy Formation may not be suitable for use as an injection zone.

According to Texaco Canada, the Methy Formation was looked at as a possible waste injection zone at their injection well in 13-15-88-8W4 but was passed over in favor of injection into the LaLoche Formation. Details of permeability and lithology in this well have not been provided.

5.4 PLANT OPERATION

Environmental concerns relating to in situ extraction have been summarized by many authors, including Carrigy and McLaws (1973), Gorrell, (1974), and Hackbarth and Nastasa, (1979). Carrigy and McLaws, (1973) have stressed that proper monitoring networks should be employed. The main concerns relate to the in situ process of extraction and to waste injection. (Refer to sections 5.3 and 5.5 respectively).

5.5 CONCERNS RELATING TO IN SITU OPERATIONS

Hackbarth and Nastasa, (1979) listed several concerns which include loss of heat and chemicals to natural water zones, and possible "uncontrollable" losses of steam through the Sewetakun fault and associated collapse features. It is also noted that combustive heating produces gases which include SO_2 and H_2 and carbon monoxide. Depending on the amount of available oxygen, SO_2 could react with the water in an aquifer to produce sulfuric acid, either within the aquifer or at points of groundwater dishcarge to the surface. Acids would enhance the solution of any underlying carbonates. Gases would also tend to migrate upwards and could accumulate in higher permeable zones.

Hackbarth and Nastasa also stress that it is essential to assess the degree of hydraulic connection between the oil sands and the underlying Devonian carbonates. Of the three pilot plant projects in the study area, the Amoco site appears to have the greatest degree of hydraulic separation from the Devonian carbonates.

Dusseault (1977) has stated that induced fractures would probably be horizontal at depths down to 450 m and vertical at greater depths. Over-pressurizing, however, could result in some vertical or inclined fracturing at any depth.

Poor abandonment techniques in old boreholes could result in easy hydraulic connections between aquifers.

Many of the concerns relating to in situ operations also apply to waste injection. The flow of natural salt springs could be increased and new springs created, and the chemical character of the spring outflows could change. Monitoring of flow rates and water chemistry should be carried out at least 3 times a year on selected springs.

5.6 POTABLE WATER

Alberta Environment has conducted test drilling and completed several wells at the Hamlet of Anzac (Winner and Kerr, 1976). Drilling with a boring rig to depths of 30.5 m resulted in the completion of only two low yielding wells out to 10 holes drilled. All the holes were drilled in till which contained discontinuous sand lenses. Gas was encountered within an aquifer in one of the unsuccessful holes and the hole was abandoned, and tar sand was encountered at another site.

Eleven deeper wells were drilled into bedrock during Alberta Environment's drilling program. All except the deepest wells were completed within sandstones units of the Grand Rapids Formation at depths of from 36.6 to 52 m. The deepest well tapped a sandstone interval within the upper part of the Clearwater Formation at a depth of 52 m. Six months after test drilling, it was found that five of the 11 wells were contaminated with oil. It was concluded that there are small dispersed accumulations of hydrocarbons throughout the aquifers in this area and that pumping induced the hydrocarbons into the wells.

Water in all the wells contained less than 1000 mg/l total dissolved solids. Saline water, however, has been reported in deeper wells, down to a depth of 61 m completed within sands and gravels of a buried channel near Gregoire Lake. The conclusion is reached that there is already natural contamination of aquifers within the study area. Some effort should be made to determine the nature and extent of saline water occurrences and of gas and hydrocarbon accumulations within shallow aquifers in the area of possible in situ oil operations, prior to the start of in situ operations.

It appears that the only possible sources of groundwater suitable for municipal or industrial needs are either buried channels, which have limited extent, or the Grand Rapids Formation. Further work will be required to determine the long-term capacity of these aquifers. Other than these groundwater sources it appears that most municipal and industrial water supplies will have to be obtained from surface water.

5.7 LONG-TERM EFFECTS

After each site is abandoned there will be some 10,000 or more wells that must be properly cemented to prevent movement of fluid between otherwise hydraulically separate units. However, some wells should be left open so that water levels, temperatures and water quality may be measured.

Prior to shutting down a field operation the water temperatures should be lowered as much as possible to the prevailing natural groundwater temperature. Hydraulic pressures should also be lowered, however, regional flow analysis should be carried out to determine the optimum residual pressure.

The major impact will be the effects of increasing the permeability and porosity of the oil sands due to removal of the bitumen.

Preliminary groundwater flow analysis by Hackbarth have shown that the oil sands have a regional permeability in the order of 10-6 cm/sec. This could easily by increased by several orders of magnitude after the in situ removal process has been completed.

Computer models will be required to assess the impact of these changes on the regional flow patterns. The impact would probably best be minimized by controlling the hydraulic pressures in the oil sands, using abandoned production wells.

The changes in groundwater quality will be more difficult to assess because of increased susceptibility of chemical compounds to become dissolved due to increased acidity of the pore water and higher flow rates. This area of concern will require considerably more investigation.

6.0 CONCLUSIONS AND RECOMMENDATIONS

Active experimental projects relating to in situ recovery are being carried out at three locations within the study area. The operators are Texaco Exploration Canada, Amoco Canada and Gulf Canada. Texaco has used steam injection during their experimental work, Amoco has used a combined forward combustion and waterflood process (COFCAW), while Gulf's experimental work is in the beginning stages with both single-well steam stimulation and mine-assisted in situ processing (MAISP) being planned.

As it will probably be several years before commercial plants are put into operation there is time to carry out more detailed groundwater studies and to install monitoring systems. Environmental impacts are likely to be local in nature over the short term but there is the possibility of long term regional effects.

The Texaco location is expected to be the most environmentally sensitive for several reasons including, 1) proximity to Fort McMurray, 2) proximity to the Clearwater River and Saprae Creek, 3) relatively thin overburden over the oil sands, and 4) the apparent lack of intervening clay or shale between the oil sands and the underlying Devonian carbonates. There are however environmental concerns at all locations. Groundwater-related problems can be difficult to both detect and predict, because they are not easily observable. There is a great need for a thorough, systematic and detailed collection of data process which should include many years of baseline data prior to the start of any commercial operations or of experimental operations. Data collection has started but should be greatly expanded. Dissemination of information is, at the present time poor, or non existent and in this regard oil company secrecy leaves much to be desired. Dissemination of information is seen as a major problem and thorough monitoring of possible effects of oil sands operations on groundwater resources will be required before, during and after the operations. This at present appears to be almost non-existent except as carried out by the oil companies themselves for their own purposes, which are largely economic only, and as stated above, even if monitoring is carried out, results tend to remain either within the oil company or to become buried in a government file. Environmental Impact Assessments as related to groundwater have tended to be highly generalized, and perhaps to some extent this cannot be avoided in preliminary stages. It is suggested that a panel of groundwater experts should be set up to prepare standards for groundwater investigations and monitoring. The operations should then conform to these standards and their compliance should be the responsibility of one specific government department. Operating licenses could be suspended if these are not up to the specified standards. Blind acceptance of Environmental Impact Assessments and other reports is discouraged. These should be viewed as preliminary drafts only. Government agencies or a panel of experts should have the opportunity to review such reports, and accept them as final only after all questions have been answered to their satisfaction, accompanied by supporting documentation.

Monitoring is an essential part of any in situ operation and background data on existing conditions prior to major extractions is important. In the area of interest, background data is poorly documented. Meteorological stations, steam gauging stations, and the Alberta Research Council's Observation Well Network are major contributions towards providing good quality background information. More data, however, is required, as these sites are remote from the pilot plants. Information is required particularly in the following areas:

1) Collection of baseline data.

As the hydrogeology of the region is poorly understood more data is required. However, additional regional test drilling and the construction of observation wells is not recommended at this time because of the high cost of carrying out such a program which requires the construction of temporary access routes, the drilling of relatively deep test holes and observation wells. In addition to these costs there would also be relatively high costs associated with the collection and interpretation of data.

We believe that a phased approach, as outlined below, would give the best results.

a) Improve the collection of baseline meteorological data and increase the number of stations on the creeks and rivers. This information will give an indication of the contribution of groundwater flow to stream flow at given locations.

In conjunction with this program additional hydrogeological mapping should be carried out, paying particular interest to groundwater discharge features. Water levels and flow measurements should be taken at selected sites, including springs, seeps, muskeg and meadow areas. Water samples should be taken for temperature and chemical analysis.

Such a study would be relatively inexpensive and should be started as soon as possible.

b) Enhance collection of data from experimental projects by working with the operators. Funds for carrying out hydrogeological testing should be made available by a government agency. These tests should be carried out in conjunction with drilling programs being carried out by the operators. Structural test holes could have selected intervals tested by the drillstem or packer test methods. Test holes that would normally be abandoned can be converted to monitor wells. Following this type of program the costs can be shared and the maximum amount of data can be collected for a given cost.

Hydrogeological studies should be made of each site, pumping test data should be collected and there should be some attempt to construct groundwater models of each site.

c) Once quantitative data has been collected from some of the test sites then regional studies of groundwater flow should be carried out.

After such a regional study has been carried out and regional models have been constructed then the impacts of pumping out grounder, pressure injection and liquid waste injection can be simulated. The effects of removing the bitumen i.e. increasing permeability and porosity can be assessed using the model for sensitivity analysis.

Such a study would be a very large undertaking but the costs would be offset by being able to locate test holes and observation wells in sensitive areas.

d) Monitor wells should be installed in specific locations and should be completed in specific formations. These sites should be selected after the construction of a regional groundwater flow model. These wells should also be completed before the first commercial plant is brought on stream, and before large pilot plant operations.

Both the Methy and the older LaLoche Formation are potential zones for subsurface waste disposal. Piezometers within these formations are required. Piezometer networks should be established through each existing experimental operation presently within the area of study, with a top priority being given to the Texaco site. These networks should include locations both up the hydraulic gradient from the site, at the site, and down the hydraulic gradient. Piezometers should be completed within all major zones of potable water, zones of possible subsurface waste injection, the McMurray basal sand aquifer, intra-oil sand aquifers, permeable zones in the uppermost Devonian carbonates, and in selected other zones. Water levels and pressures, water temperatures and water chemistry should be monitored.

2) A more detailed evaluation of the impacts of liquid waste injection should be carried out. Specifically the requirements for testing and monitoring of the injection wells should be greatly increased. Permeability tests should be carried out in formations above and below the disposal zone. Injection or pumping tests should be carried out on the disposal zone.

Computer models of the disposal process should be undertaken by the operator who should demonstrate the feasibility of the scheme.

Once the feasibility of the proposed disposal system has been satisfactorily demonstrated then an independant body (e.g. University, Environment or Research Council) should then assess the regional impact of the proposed scheme using regional flow models. This same body should be responsible for monitoring wells outside of a given lease but the costs of this could be born by the operator.

3) Abandonment of a commercial field should have all wells properly plugged and sealed except for some which would be monitored. The formation temperature should be returned to as near-normal as possible. Further work should be carried out as to the type of fluid to be left or injected into the abandoned bitumen zone.

Monitoring of groundwater levels, temperatures and chemistry should be carried out for an extended period of 10 to 12 years. The frequency of measurements would decrease with time.

4) Groundwater Monitoring - Initially, emphasis should be placed on collecting baseline data near experimental sites. This will minimise costs and hence allow an earlier start on collecting baseline data. Being near to the experimental sites will also allow for early detection of changes in the groundwater regime.

Some general comments on groundwater monitoring systems are in order:

The costs of monitor wells involves both installation and operating costs.

Installation costs involve site access, which in this area tends to be high and drilling costs. Access costs can be minimised by installing monitor wells near to experimental sites. Well construction costs can be kept to reasonable levels by installing multiple-port piezometers in the same hole and by taking advantage of test drilling programs.

In order for the monitoring program to be effective data must be collected and analysed. Manual readings of water levels will not give adequate baseline data, continuous recording of water level data is preferred. In larger diameter (100 mm and up) wells float activated chart recorders can be used. In multiple piezometer installations and deeper wells pressure transducer systems will be required.

In the existing observation wells in the oil sands areas most wells are equipped with float activiated chart recorders. In many cases these recorders fail in extremely cold weather and charts are collected by helicopter. Under these conditions operation costs become very high, gaps in records result from equipment failure and the charts are processed manually.

It is strongly recommended that the data collection and processing be automated. Data can be transmitted to the "GOES" satellite on a daily basis, sites need only be visited when there is a failure which will reduce the operating costs and minimise the period of lost records.

Processing the data can be economically carried out by computer, which will also allow data smoothing to be carried out and trends to be identified. Paper charts should be digitised and processed in the same way.

Water temperatures and water samples should be taken manually and this should be taken into account when installing piezometers. Temperatures could be monitored automatically if significant changes are observed. The frequency of sampling could be increased if significant changes are detected.

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APPENDICES

Site Specific Data Summary

APPENDIX A

AMOCO TEST SITE (Block 1)

Location: Sec. 25, Tp. 85, Rge 8W4 (figures 4-8, 4-9)

References: Benthin & Orgnero, 1977
Lombard-North, 1974
Giguere, 1977
Carrigy & McLaws, 1973
Hackbarth & Nastasa, 1979

Method of Extraction: COFCAW process (5-year experimental program terminated Jan., 1981 to allow review of results)

Test Pattern: 1958 - 1962: experimental wells & field tests near sec. 5-86-8W4

1963: test site moved to sec. 25-85-8W4

From 1977: 20 producing wells, 12 injector wells on pattern shown on Figures 4-10 to 4-12 (None 5-spot pattern). Peak production expected to be $130m^3$/day

Giguere, (1977) indicates a possible development schedule as shown on Figure 4-13

Overburden: Depth to top of McMurray ranges from 260 to 290 m, best pay zones generally below 300 m depth. The overlying formations are the Clearwater, Grand Rapids, Joli Fou and La Biche Formations and drift. (30 - 60 m of La Biche-Joli Fou and 45-60 m of drift)

Base of Oil Sands: Lowermost oil sands generally underlain by 7 to 10 m of basal clay (see figure 4-14, 4-15 and 4-16)

Water Requirements: 16,000 m^3/day plant would require injection of 80,000 m^3/day of water, but produced water will be re-used, therefore, net water supply requirements will be much less than that injected (Giguere, 1977)

Source Water Aquifer: Grand Rapids "A" and "B" sands - several wells (figures 4-17 and 4-18). Total production-no-data. Aquifer transmissivity-average 13.4 m^2/day (900 igpd/ft). Theoretical long-term capabilities: about 3.8 to 7.6 L/s (50-100 igpm) each.

Water quality: Average about 940 mg/L total dissolved solids, 15 mg/L Cl.

Other possible aquifers: 1) sand and gravel within drift, both on upland; and in buried valley near Gregoire Lake, (TDS 14,000 mg/L, Cl 7800 mg/L near Gregoire Lake and est. yield 38 L/sec. 2) McMurray Formation and older aquifers - more likely to be used for disposal of produced water.

Possible Waste Water Disposal Zones:

1) Basal McMurray water sands (Lombard-North/74) 9 to 15 m thick in and near block 1.
   - generally "low" permeability
   - injectivity capability - 7.6 L/sec
   - water chemistry - TDS 7300 mg/L and Cl .3600 mg/L from spring on Clearwater River
2) Upper Methy (Lombard-North, 1974) 30 m thick
   - water saline (connate water)
   - injectivity capability 7.6 L/s (100 igpm) (?) but could be higher if vuggy porosity is widespread
3) LaLoche Formation (granite wash) - (Lombard-North, 1974) 9 m thick

Produced Water (Lombard-North, 1974): 10,300 mg/L TDS
3,350 mg/L Cl

- temperature of 65-72 C
- water quality compatible with basal McMurray, Methy and LaLoche aquifers
- heat in water should be used prior to disposal

Possible Environmental Problems & Suggested Control Monitoring:

1) Possible depletion of Grand Rapids aquifers with associated lessening of spring and seepage

outflows from the Grand Rapids Formation and possible lessening of stream baseflows at location north and northwest of Stony Mountain upland.

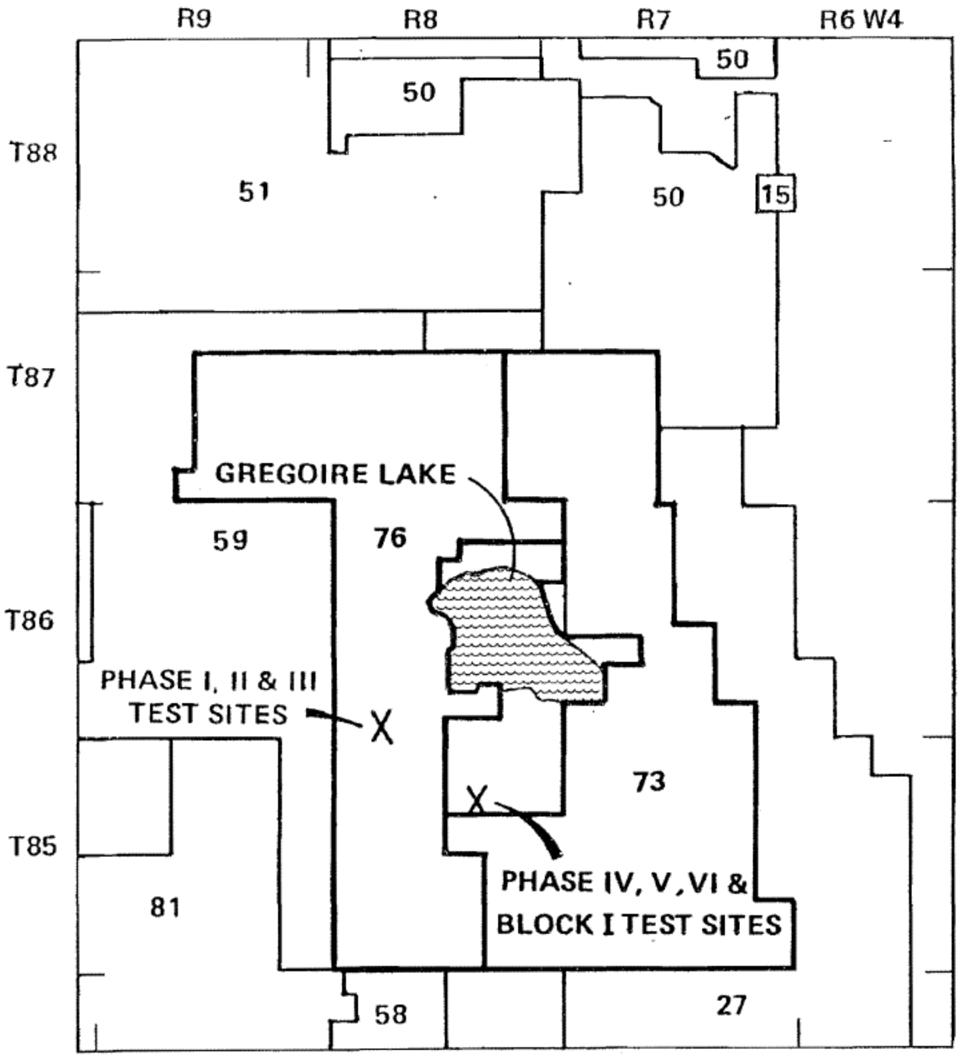
- proposed control: management of aquifer to avoid over-pumping.
- suggested monitoring: suitably located observation wells, locate and monitor possible spring outflows.

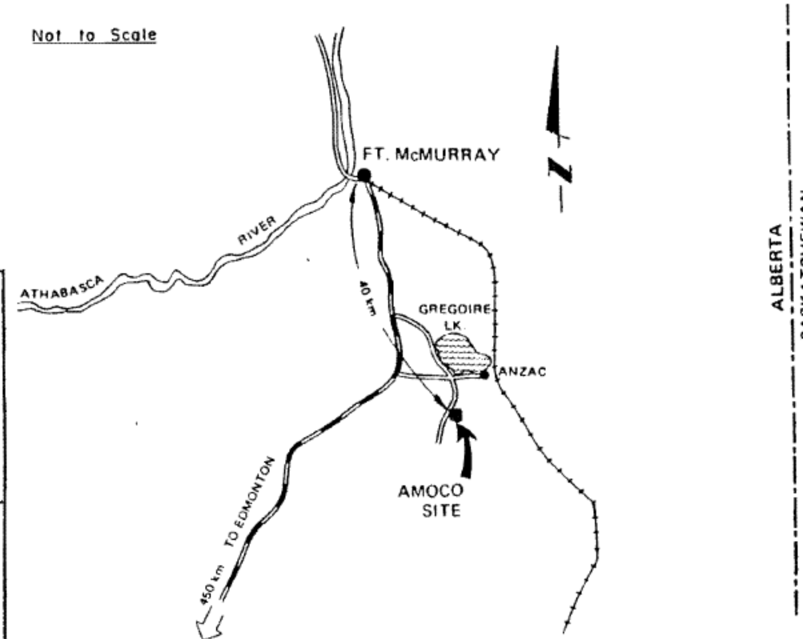
2) If waste disposal takes place into McMurray and/or deeper aquifers:

- spread salinization of fresh water aquifers within,
  - a) water-bearing McMurray Formation to the east of the test site, and
  - b) buried valley (drift) aquifers which cut down into the McMurray Formation to the east of the test site.
- increase in flow rate of saline springs from basal McMurray and intra-McMurray aquifers along Clearwater, Hangingstone and Christina Rivers
- possible changes in groundwater chemistry
- possible breaking-out of saline water in stratigraphically higher freshwater aquifers and onto the ground surface
- possible changes in permeability of injection zones
- possible increased temperature of groundwater and surface water
- increased groundwater temperature could result in more rapid groundwater movement and chemical changes within the groundwater body
- possible increased solution of Devonian carbonates could occur within resultants increase or spread of karstic features

- possible fracturing of overlying rocks
- proposed controls: cool produced water before disposal, keep injection pressures low, limit the amount of waste water injection, re-cycle produced water
- suggested monitoring: monitor water levels, formation water temperatures, injection rates and pressures, spring outflows

3) Possible problems as a result of COFCAW process:
   - preheat phase involved ignition, and injection of air at above fracture pressure to maximize flow capacity; the fracture pattern can be uncertain
   - possible problems, controls and monitoring are similar to those listed for waste disposal, although the risk of thermal pollution is much greater



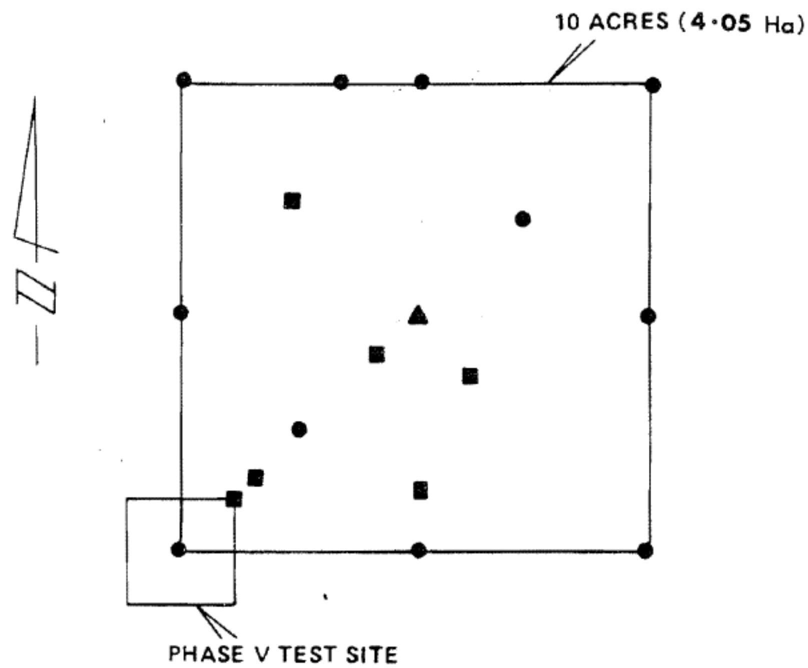


GREGOIRE LAKE

AMOCO

ACTIVITY MAP

Fig. A-I



PHASE VI TEST SITE

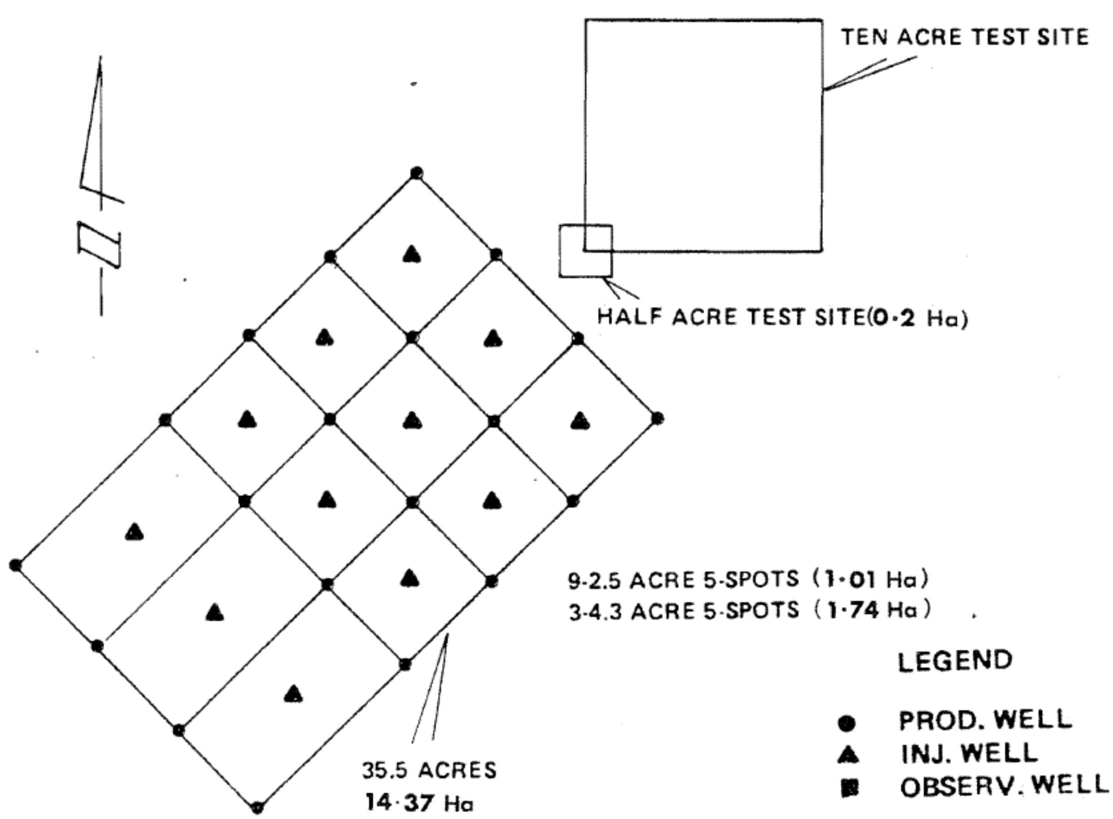
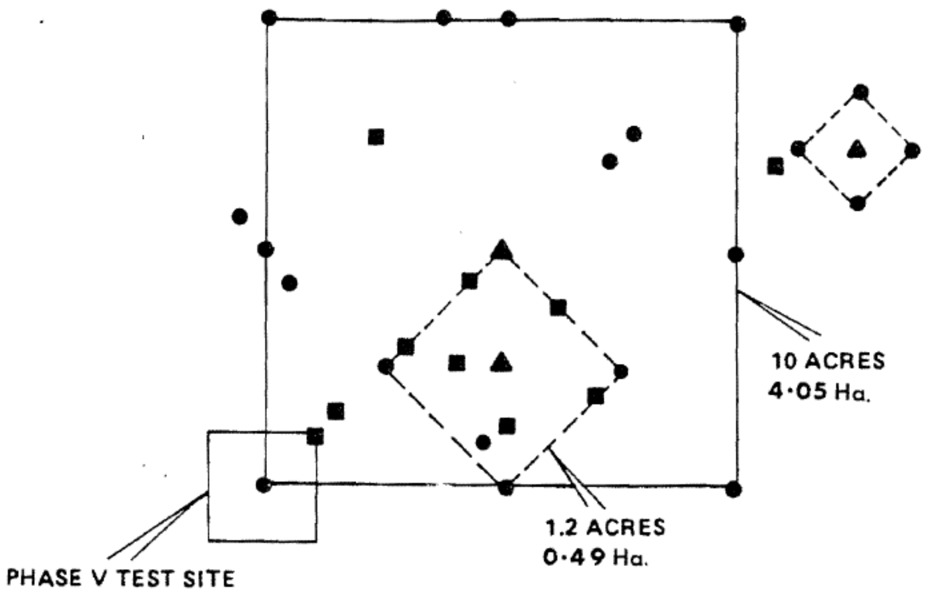


FIGURE No. A – 2
BLOCK I TEST SITE (1974)

AMOCO TEST SITE



PHASE VI TEST SITE
AND MINI-TEST

LEGEND

● PROD. WELL
▲ INJ. WELL
■ OBSERV. WELL

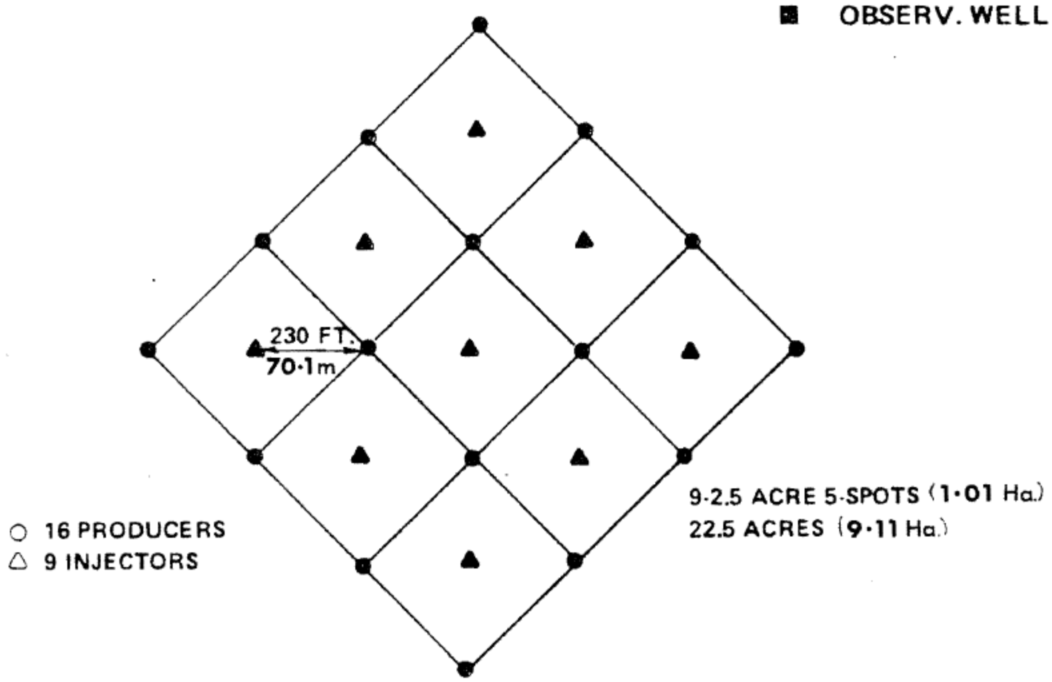


FIGURE No. A – 3
BLOCK I TEST SITE (1977)
AMOCO TEST SITE

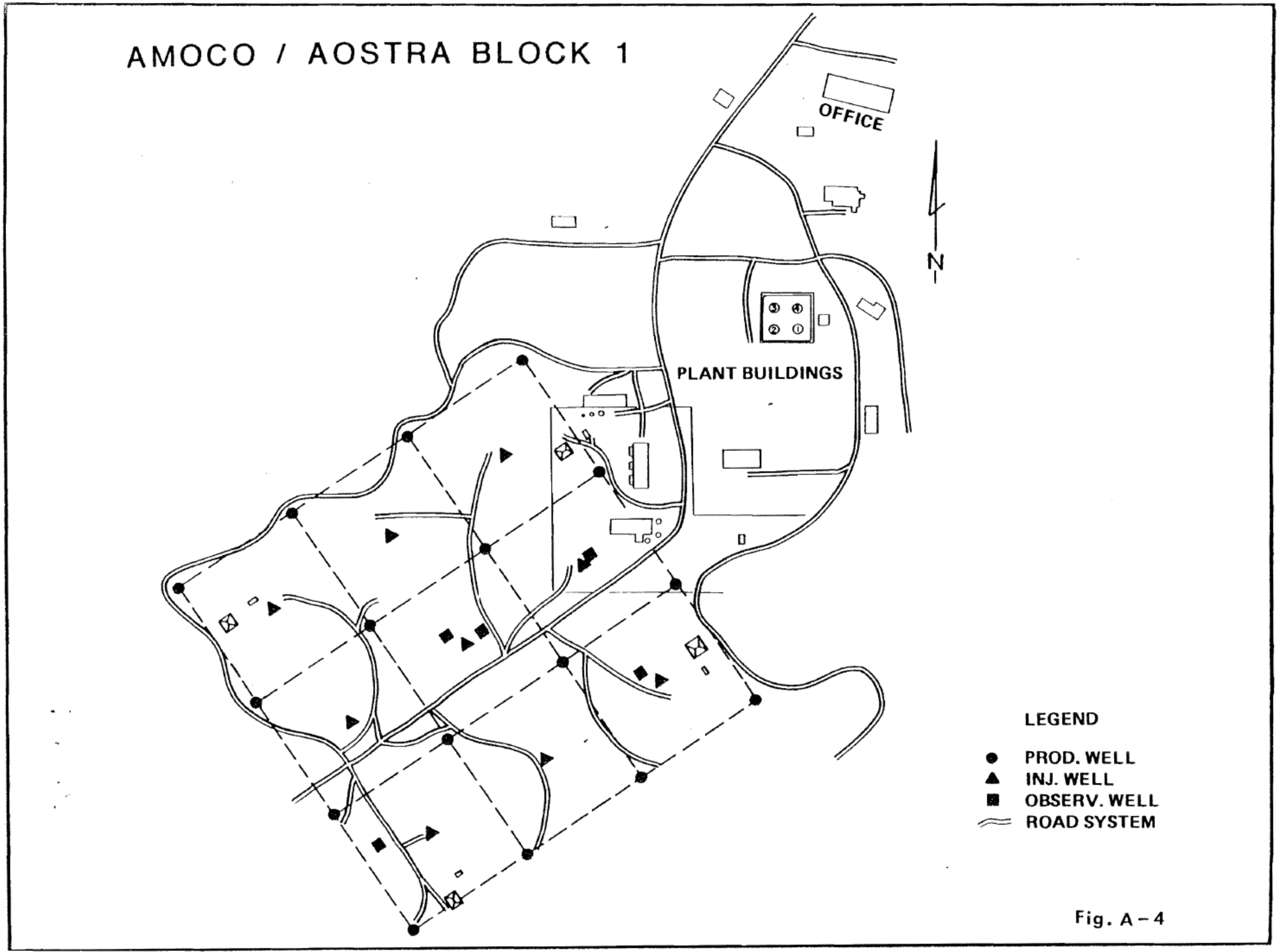

AMOCO / AOSTRA BLOCK 1
OFFICE
PLANT BUILDINGS
N
LEGEND
PROD. WELL
INJ. WELL
OBSERV. WELL
ROAD SYSTEM

Fig. A-4

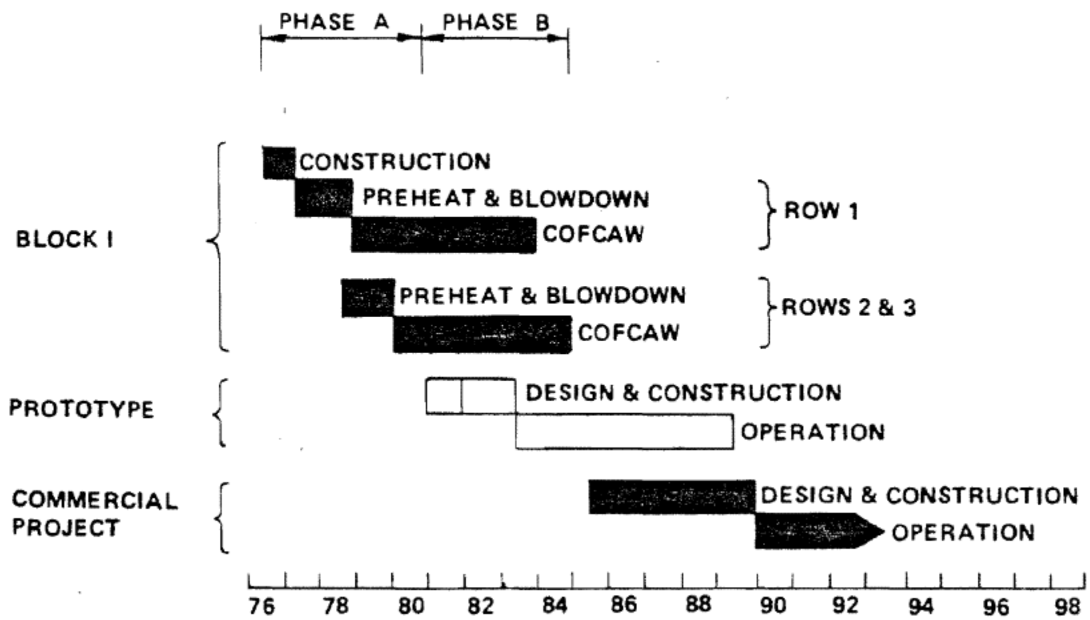
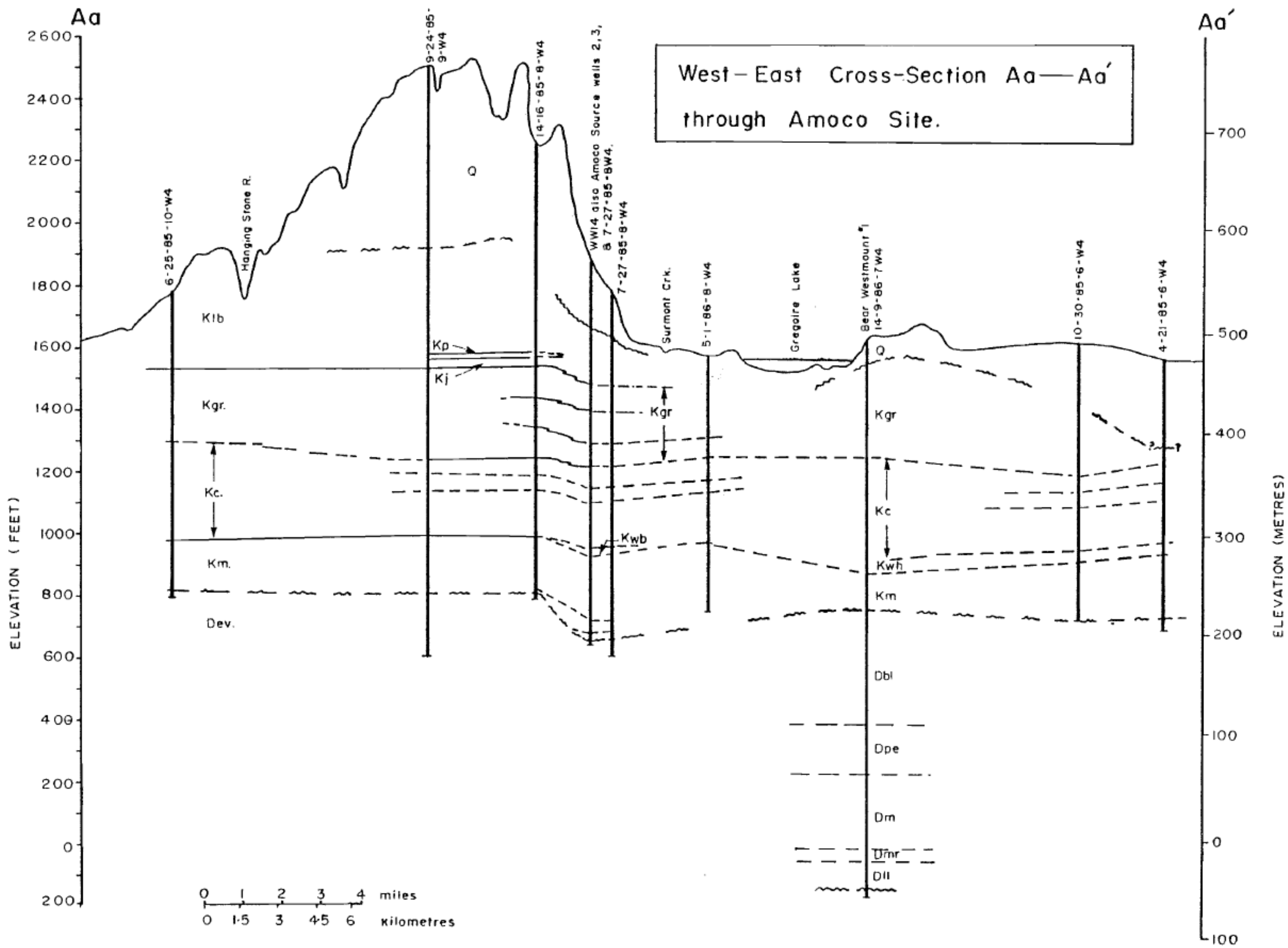
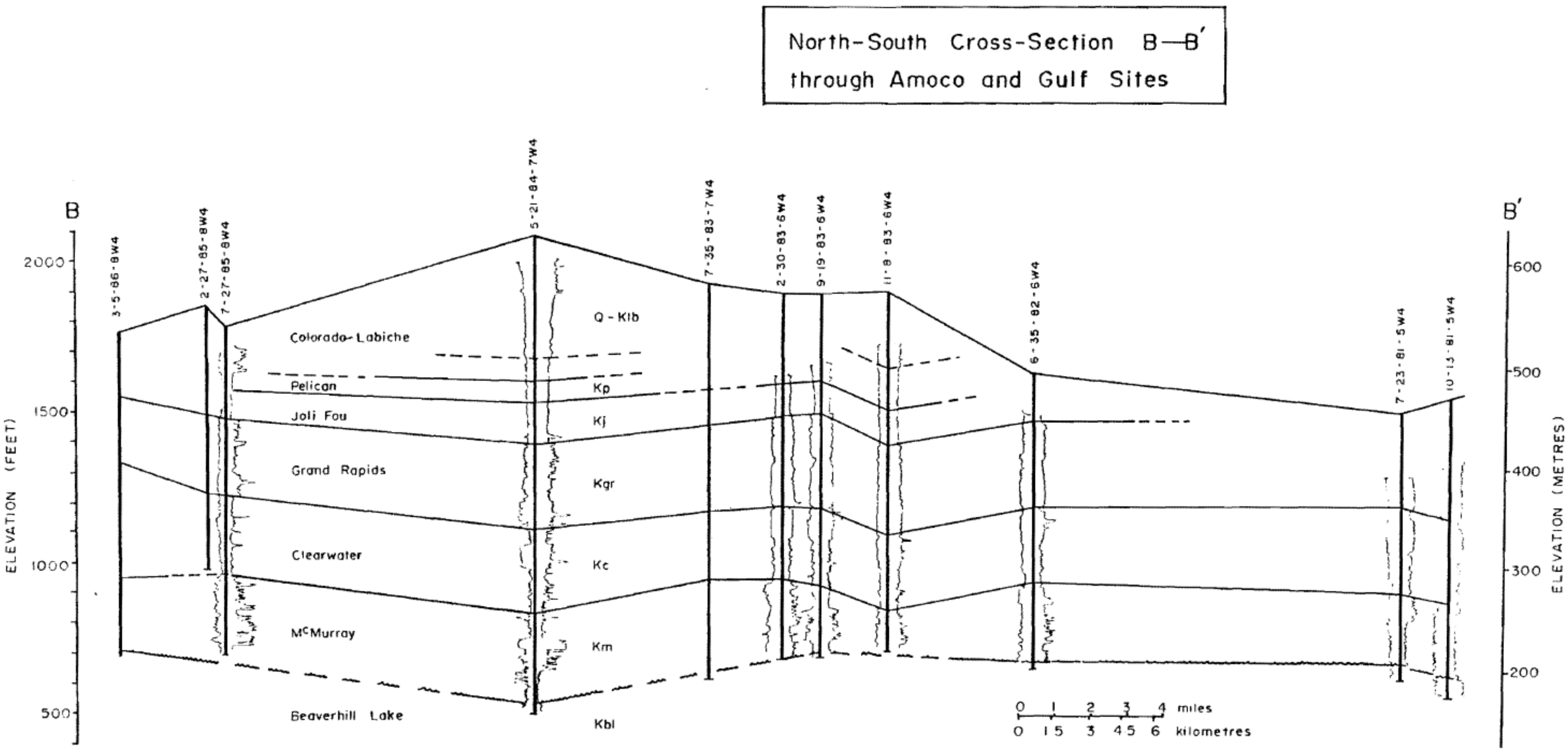


FIGURE No. A–5
POSSIBLE OIL SANDS DEVELOPMENT SCHEDULE (AMOCO)



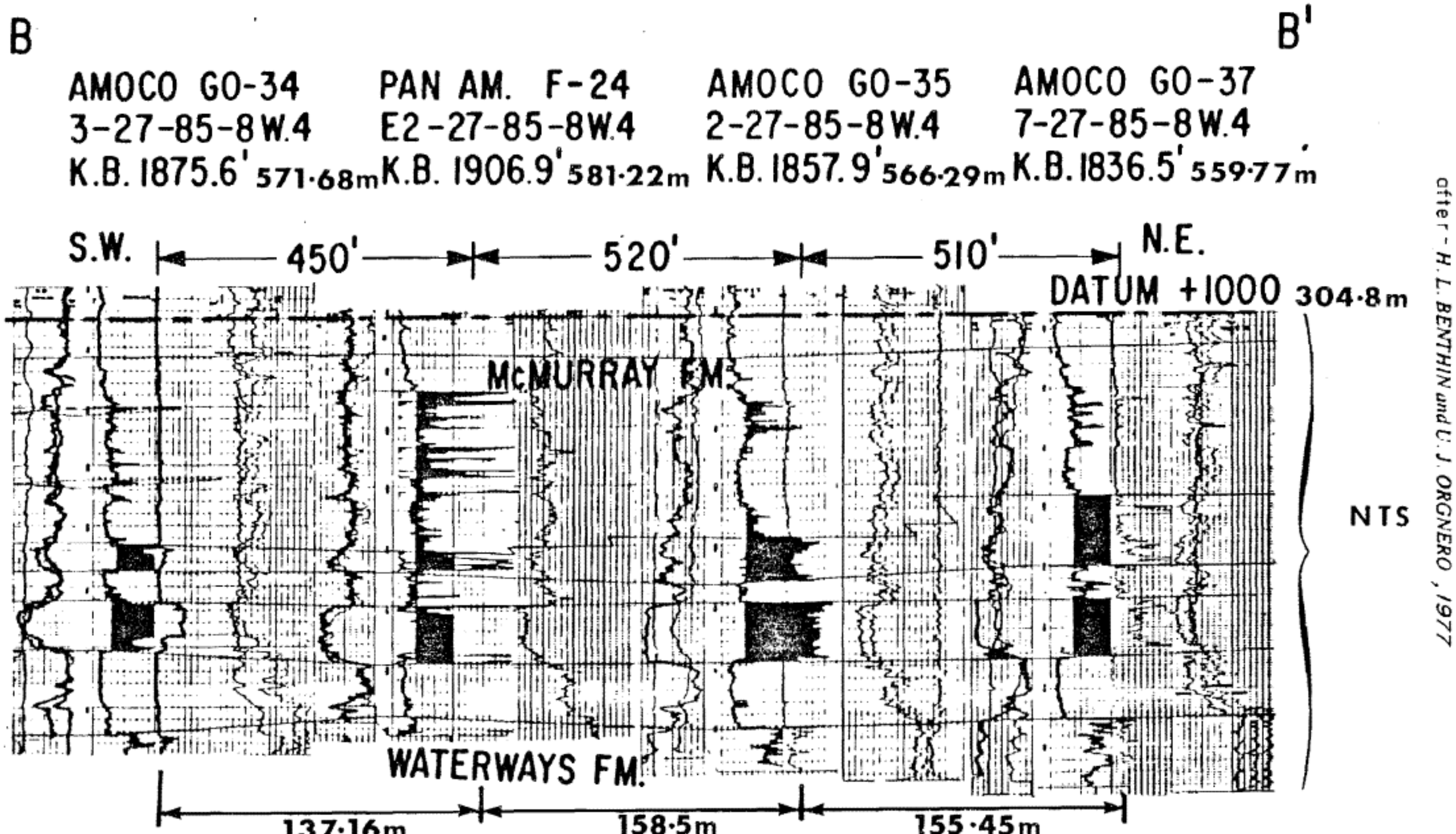
FOR LOCATION OF SECTION SEE FIG. 4-2

Fig. A-6



FOR LOCATION OF SECTION SEE FIG. 4-2

Fig. A-7



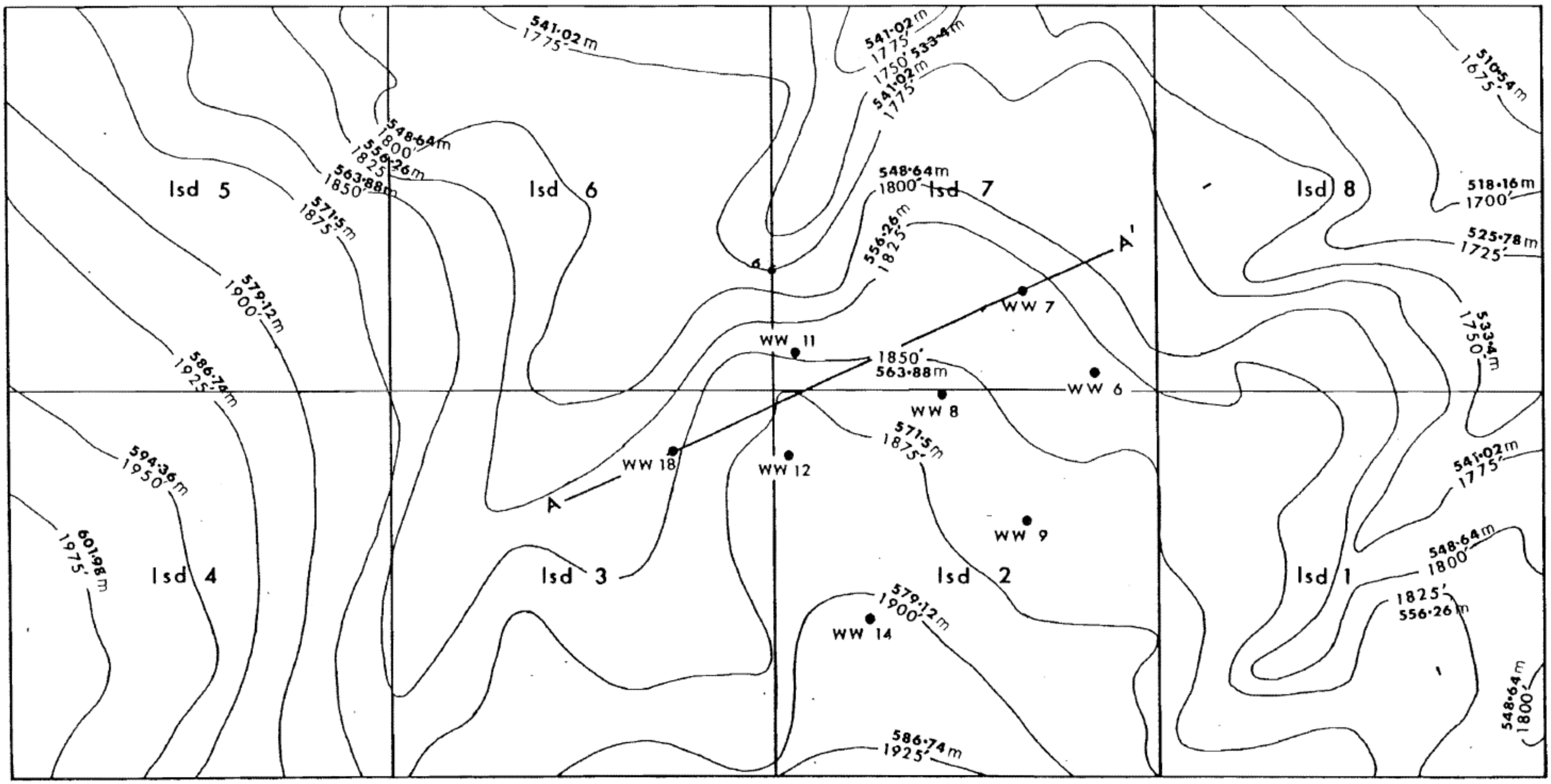
Block 1 structural cross section.

FOR LOCATION OF SECTION SEE FIG. 4-2

FIG. A-8

LOCAL TOPOGRAPHY: WATER WELL LOCATION
AMOCO CANADA PETROLEUM CO. LTD.

S 1/2 - 27 - 85 - 8W4



LEGEND

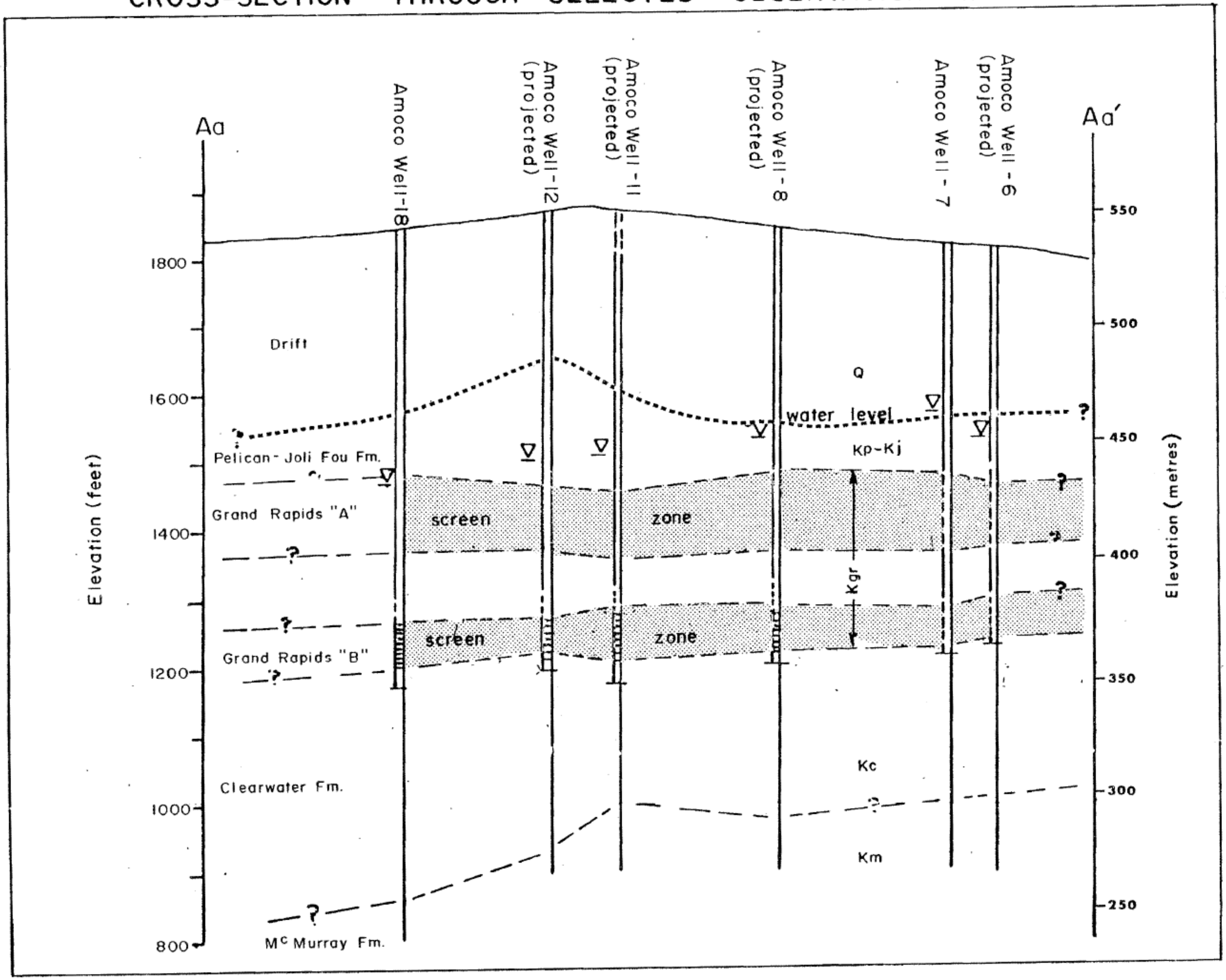
•WW2 Well

Topographic Contours

Not to Scale

FIG. A-9

CROSS-SECTION THROUGH SELECTED OBSERVATION WELLS



APPENDIX B

TEXACO TEST SITE

Location: sec. 15, tp.88, rge 8W4 (in l.s.d. 12 & 13)

References: None

Test Pattern: Pattern 1 (started 1973): 12 producing wells, 6 injection wells over 4 ha.

Patterns 2 (started 1976): 6 produces, 7 injection wells over 1.5 ha.

- production in 1978 over 16,000 m^3
- recovery in pattern 2 reached 39% bitumen in place
- testing current systems to be completed over next 5 years
- a third pattern utilizing horizontal wells is to be initiated

Method of Extraction: Steamflooding and additives using Wizard Lake light crude oil as a dilutent.

Overburden: Top of McMurray 73-80 meters below ground surface.

- overlain by Clearwater shale and drift
- site is 1.7 to 2.5 km south and southwest of Saprae Creek where drift is thinner. Further downstream (to NW), Saprae Creek cuts down into the McMurray Formation. Geological cross sections are shown in figures 4-19 and 4-20.
- Clearwater River valley is about 4 km north of test site. This valley is cut through the McMurray Formation

Base of Oilsands: Oilsands rest directly on Devonian carbonate or have thin intervening clay interval. Basal water and sand appears to be absent.

Water Requirements: No information. Assumed to be very high. Carrigy and McLaws, (1973) estimate the use of 4 m^3 of water for every m^3 of partially upgraded bitumen produced, and approximately 6.7 m^3 of water for a m^3 of completely upgraded synthetic oil.

Source of Water: No information.

Shallow Aquifers: No major ones identified.

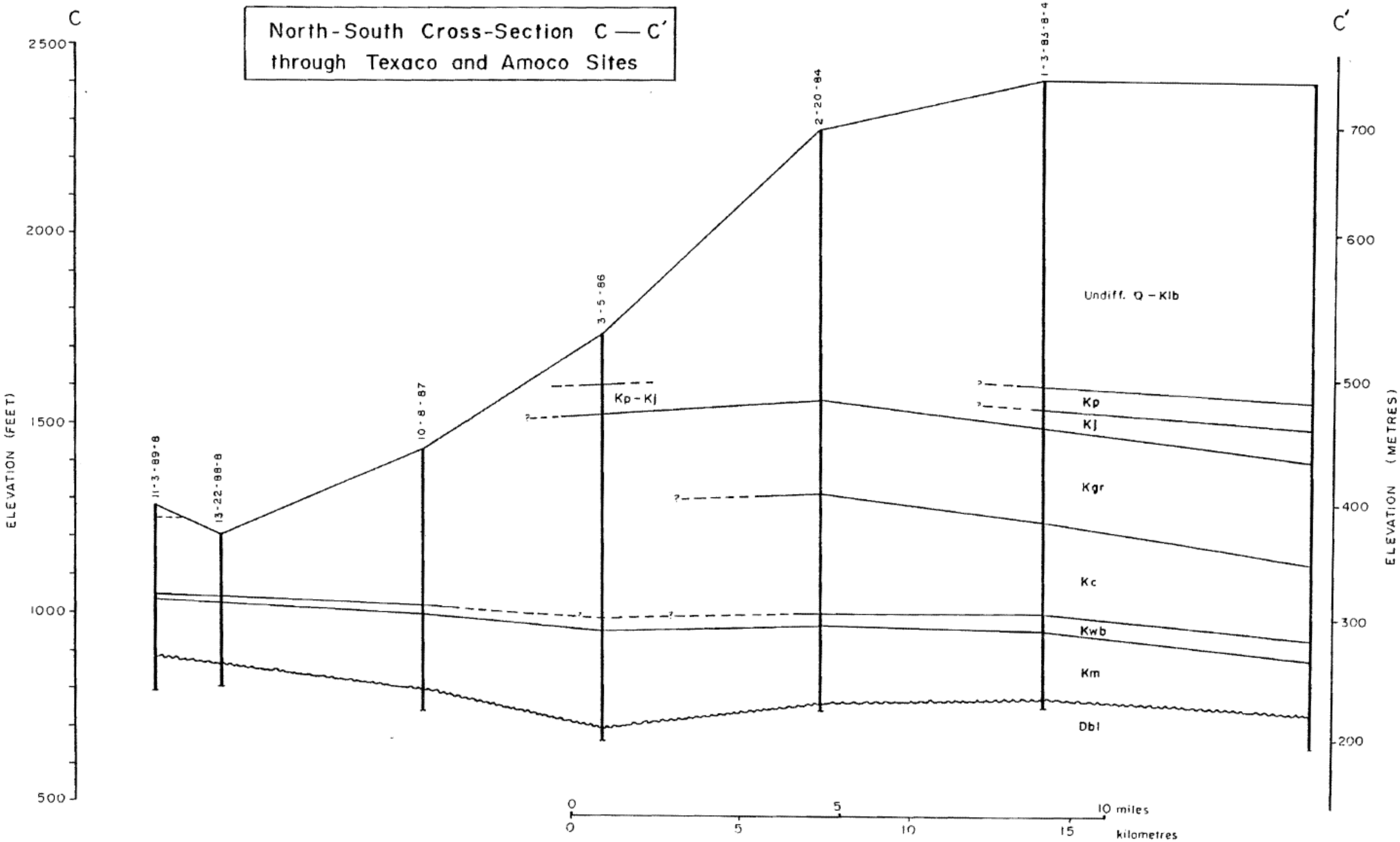
Water Disposal Zones: 1) LaLoche Formation (granite wash) has been used as disposal zone.

Produced Water: No information.

Possible Environmental Problems & Suggested Controls & Monitoring:

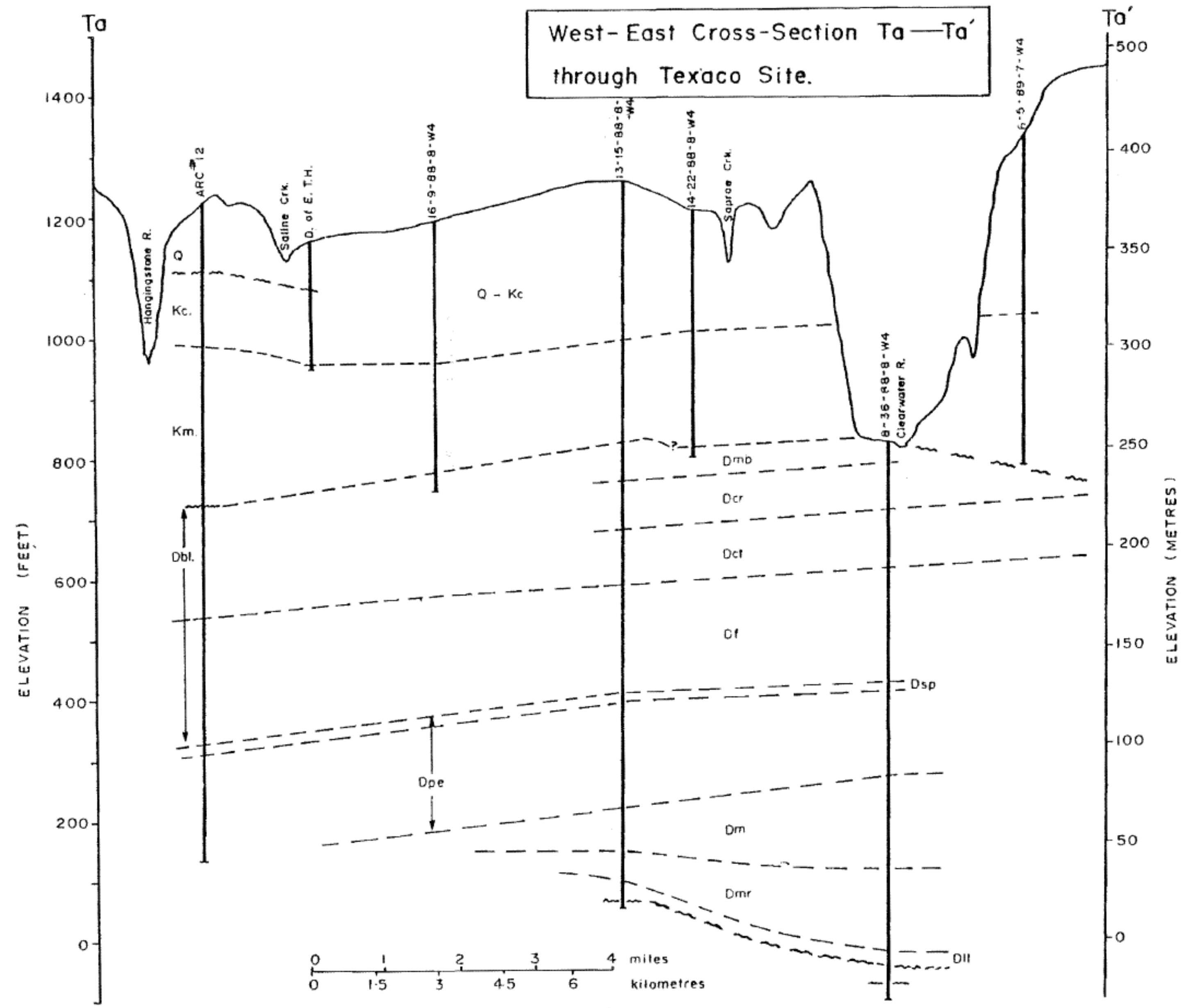
1) Possibility of blow-outs at surface. At least one such blow-out if known to have occurred at a location 183 to 214 meters from the injection well and is attributed to fracturing the overlaying Clearwater shales. Other blow-outs could occur, either at the surface at or near the test site, or at places further from the site where the overburden is thinner as along Saprae and Clearwater River valleys.

- proposed control: use of lower injection pressures
- suggested monitoring: careful control and monitoring of injection pressures; - detailed survey of surficial features and vegetation patterns with 4 km radius of test site; study of surface lineaments, if any, to determine possible fracture zone
- detailed survey of valley flow and walls of Saline Creek, Saprae Creek and Clearwater River to locate possible zones of weakness, identify spring and seepages zones and fracture patterns



/FOR LOCATION OF SECTION SEE FIG. 4-2

Fig. B-1



FOR LOCATION OF SECTION SEE FIG. 4-2

Fig. B-2

APPENDIX C

GULF-NUMAC TEST SITE (SURMOUNT BLOCK)

Location: sec 30, tp. 83, rge 6W4

References: Mossop, 1978

Test Pattern: Not established, experimental tunneling proposed to be carried out over a 7 year period, single well experimental steaming tests were planned for start-up in late 1980.

Method of Extraction: Experimenting with both single well injection (huff and puff), and with Mine Assisted In Situ Processing (MAISP).

- fracturing experiment recently completed
- use injection pressures of up to 12,000 kPa

Overburden: 275 to 290 meters to top of McMurray Formation. Geological cross sections are shown in Figure 4-21.

Overburden consists of Clearwater, Grand Rapids, Joli Fou and La Biche Formations and overlying drift. Meadow Creek flows across section 30, but is not deeply incised. Overburden thins slowly to east, northeast and southeast to about 210 m at 10 km from the site.

Base of Oilsands: Appear to be directly on Devonian carbonates at test site, but basal water sand is present immediately to east.

Water Requirements: No information.

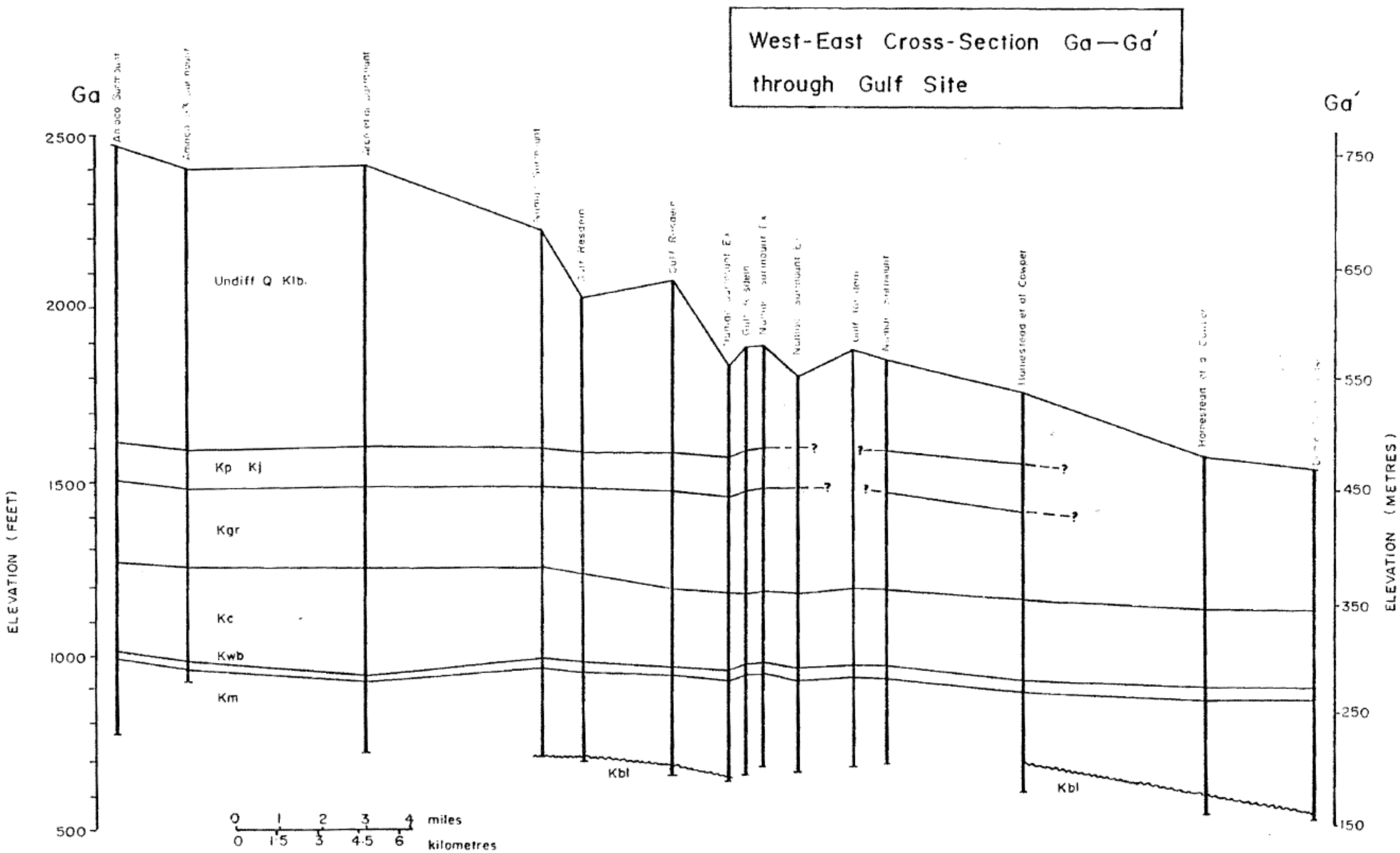
Source of Water: No information.

Possible Waste Water Disposal Zones: Unknown.

- a Precambrian test is currently drilling in 7-32-83-6W4

Produced Water: Analysis of water from Numac Surmount well 1-31 OV-83-6 in 1-31-83-6W4 included here as table No. 5-1. (sodium 2350 mg/l, chloride 4330 mg/l)

Possible Environmental Problems and Suggested Controls & Monitoring: Similar to those for Amoco and Texaco sites.



FOR LOCATION OF SECTION SEE FIG. 4-2

Fig. C-1