GEOLOGICAL SURVEY OF CANADA
COMMISSION GEOLOGIQUE DU CANADA

Open File 3946

HYDROGEOLOGY OF HEAVY OIL AND TAR SAND DEPOSITS: WATER FLOW AND SUPPLY, MIGRATION AND DEGRADATION

FIELD TRIP NOTES

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November 2000

Hydrogeology of Heavy Oil and Tar Sand Deposits:
Water Flow and Supply, Migration and Degradation.
May 24th - 28th, 2000.

Field Trip Notes

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Itinerary

Wed. May 24th (Day 1)

8:00 am	Depart Calgary, head west on HW1 to Bow Valley Provincial Park and the Many Springs parking area.
9:00 am	**Stop 1 - Many Springs.** An example of a shallow local flow system.
10:00 am	**Coffee and Doughnuts**
10:30 am	Depart Many Springs and head north on 1X to 1A. Head west on 1A to Jura Creek. Park at Continental Lime.
11:00 am	Hike from parking area 5 km up Jura Creek to outcrop of Exshaw Shale.
12:00 noon	**Stop 2 - Exshaw Shale Type Section.** Spend time examining type section and **lunch** on the outcrop.
1:30 pm	Start hike back to bus.
2:30 pm	Depart for Banff via 1A and 1.
3:00 pm	**Stop 3 – Cave and Basin Hot Springs.** An example of a deeper flow system. Compare and contrast to Many Springs. Origin of H_2S in the springs, the Banff Springs Snail.
4:00 pm	Depart Cave and Basin for Upper Hot Springs
4:10 pm	**Stop 4 – Upper Hot Springs.** Brief discussion on seasonal variations in the flow chemistry. Swim in the pool.
5:30 pm	Depart Upper Hot Springs and head east on 1 for Canmore.
6:00 pm	Arrive at Canmore, Check into hotel. Informal get together at the **Rose and Crown for dinner and fluid flow**.

Thur. May 25th (Day 2)

8:00 am	Depart Canmore Hotel, head to White Mans Gap Dam overlooking the Canmore town site.
8:15 am	**Stop 5 – White Mans Gap Dam and Grassi Lakes.** Examine Nisku/Arcs outcrop and discuss reservoir porosity/permeability. Look at the Transalta Utilities Dam and piezometers. Hike down a steep path to Grassi Lakes (1km) examining the Leduc/Cairn outcrop along the way. Discuss reservoir porosity/permeability and hike back to the bus.
9:30 am	Depart White Mans Gap Dam back through Canmore, cross H 1 and head east on 1A. Turn off right (south) after Radnor into Wildcat Hills Gas Plant.
10:00 am	**Stop 6 – Wildcat Hills Gas Plant.** Discuss reservoir and productio characteristics of fields along the Wildcat Hills Thrust
10:30 am	Depart Wildcat Hills Gas Plant, drive west on 1A then turn north on the Forestry Trunk Road. Turn right (north) after 20 km at the Richards Road crossroads (end of blacktop). **Coffee and Doughnuts on the bus.**
11:10 am	**Stop 7 – Waiporous Lookout.** Discuss foothills hydrogeology.
11:40 am	Depart Waiporous Lookout, continue north on the Forestry Trunk Road, heading for **Mountain Aire Lodge** on the left just before the Red Deer River bridge.
12:30 pm	**Stop 8 – Red Deer River – Lunch at the Mtn. Aire Lodge.** Groove to Madness CD's over lunch along the Red Deer River.
1:30 pm	Depart Red Deer River, head north on the forestry trunk road to James Pass, south-west of Stawberry Ridge.
2:00 pm	**Stop 9 – South end of Brazeau Ramp.** Discuss Foothills hydrogeology. Look at the lateral ramp of the Brazeau thrust and a significant foothills recharge site.
2:45 pm	**Stop 10 – Marble Mountain (west flank of Brazeau Ramp?).** Discuss Foothills hydrogeology. Look at the lateral ramp of the Brazeau thrust
3:00 pm	Depart Marble Mountain, head north on the forestry trunk road then turn northeast on H. 591 (and H. 54) through Caroline. Turn right (south) on HW 22 and after 3 km turn off right (west) on back road to Raven Fish Hatchery. Discuss Caroline Gas Plant on the bus.

4:00 pm **Stop 11 – Raven River Trout Station.** See the discharge point of a local flow system and discuss the implications of the water geochemistry.

4:30 pm Depart Raven River Trout Station go north on 22, turn east on 54 then north on 2 to Edmonton.

6:30 pm Arrive in Edmonton check into hotel. **Dinner**

Fri. May 26th (Day 3)

8:00 am Depart Edmonton on 21 north to Redwater.

8:30 am **Stop 12 – Redwater Field.** Discuss the characteristics of the Redwater Field and models of migration up reef trend

9:00 am Depart Redwater, head north on HW63 to Marianna Lake. **Coffee and Doughnuts** on the bus as we watch a video on the Athabasca Tar Sands.

12:30 pm **Stop 13 - Lunch** at Marianna Lake picnic area. Historical overview of the Athabasca Tar Sands

1:00 pm Depart Marianna Lake north on 63 for Ft McMurray.

3:00 pm **Stop 14 – Syncrude Mine Tour**. Tour the syncrude mine with a special emphasis on the earth sciences.

5:00 pm Depart Syncrude for Ft. McMurray

5:30 pm Arrive in Ft. McMurray and check into the Sawridge Hotel. **Dinner**.

Sat. May 27th (Day 4)

7:30 am Depart Sawridge Hotel for Fort MacKay

8:30 am **Stop 15 – MacKay River Amphitheatre section.** Hike in and examine outcrop.

9:30 am Depart Amphitheatre section for the Beaver River sandstone quarry. **Coffee and Doughnuts** on the bus.

10:00 am **Stop 16 – Beaver River Sandstone Quarry.** Hike in and examine outcrop.

11:30 am **Lunch at Wood Bison Gateway and Viewpoint Interpretive Reclamation Area**

12:30 pm	Depart lunch spot for Saline Creek outcrops.
1:30 pm	**Stop 17 – Saline Creek.** Examine saltwater spring and Oil Sands outcrop.
2:30 pm	Depart Saline Creek for Hangingstone River outcrop.
3:00 pm	**Stop 18 – Hangingstone River Outcrop.** Examine oil sands outcrop
4:00 pm	Depart Hanging Stone outcrop for tour at Oil Sands Discovery Centre.
4:30 pm	**Stop 19 tour at Oil Sands Discovery Centre (open until 6:00 pm).** When finished with tour walk across the street to the Sawridge hotel.
7:00 pm	**Wrap-up Banquet – Sawridge Hotel.** Dinner followed by a trip summary slide presentation and panel discussion with audience participation on hydrocarbons and hydrogeology (over beer).

Sun. May 28th (Day 5)

7:00 am	Depart Sawridge Hotel south on 63 for Edmonton. **Coffee and Doughnuts** on the Bus.
1:00 pm	**Stop 20 – Leduc #1 Visitor Information Centre – Lunch.** Eat lunch at the visitor information centre and look at the Leduc #1 rig.
2:00 pm	Depart Leduc #1 Visitor Information Centre south on 2 to Calgary.
5:30 pm	Arrive back in Calgary.

Because of their large size, great depth, and slow circulation rate, basin scale flow systems are inherently difficult to study. As an analogy, we can examine controls on fluid flow, water/rock interaction, heat transfer, and biogeochemical reactions in smaller scale flow systems. Several deep-circulating thermal springs in the Rockies provide such an opportunity. We will stop at Many Springs and the Banff thermal springs to examine factors that control the development of these features and discuss how these may relate to larger scale fluid flow systems.

At the first stop we will park at the Many Springs trailhead in Bow Valley Provincial Park. The springs are a short walk from the parking area and can be viewed by following an interpretative trail. As the name implies, there are *many* springs in a low swampy area forming a large interconnected pool. Individual outlets are easily observed by gastropod shells being tossed around by the spring discharge ("dancing sand grains"). Water temperatures vary between outlets, with the highest being 11 °C. As illustrated by the interpretative sign at the viewpoint, the water temperature remains relatively constant throughout the year, despite seasonal variations in air temperature, indicating that temperatures are controlled by circulation through the ground water system. A generalized geological map and cross-section of the area (Fig. 1.1) illustrate the association of the springs with the McConnell Thrust. The thrust is readily observed at the Mount Yamnuska view, where the steep cliff formed by Cambrian carbonates overlies the tree-covered slopes formed by Upper Cretaceous sandstones of the Brazeau Formation.

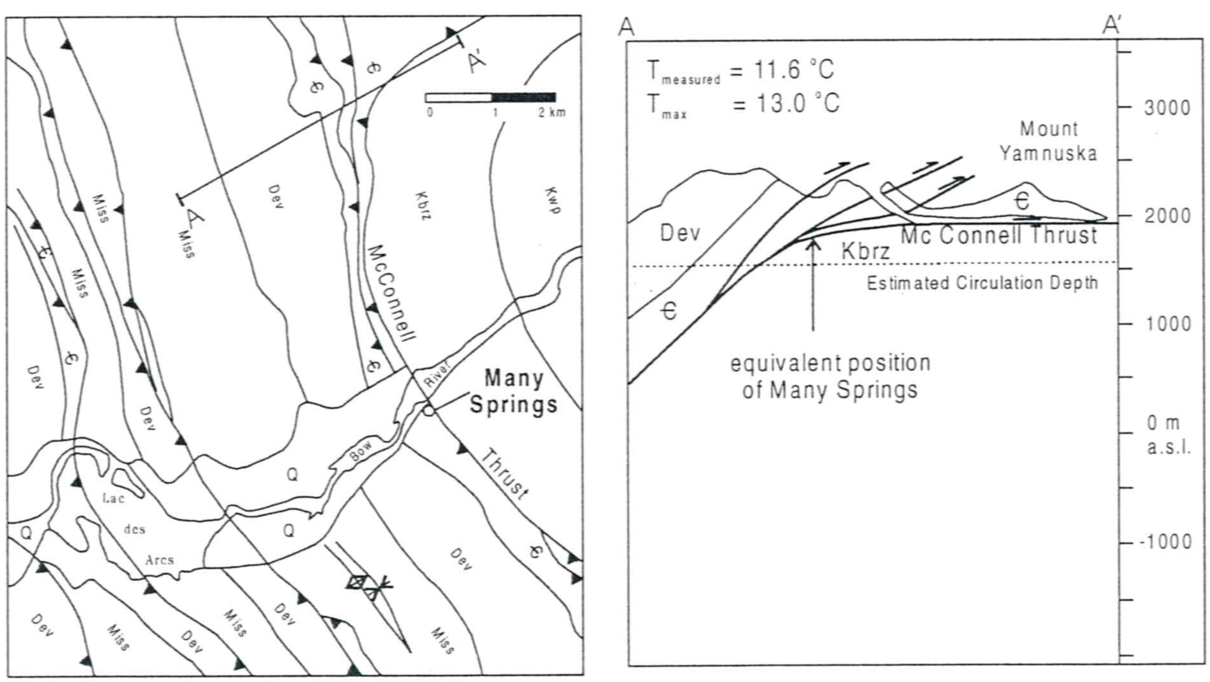


Figure 1.1 Geological map and cross-section of the Many Springs area. The cross section illustrates the estimated circulation depth based on a local geothermal gradient of 21 °C/km and a calculated maximum temperature of 13 °C (based on the chalcedony geothermometer).

Faults play an important role in the development of spring systems, particularly thermal springs. A generalised fault zone architecture is illustrated in Figure 1.2. Here we see that faults are characterised by a core zone of highly deformed material that is generally broken into small grain sizes (fault gouge, cataclasite, etc.). This core zone is surrounded by a damage zone where the protolith is less deformed, but still heavily fractured and characterised by the development of small subsidiary faults. The fault core and damage zone have contrasting effects on the bulk permeability of the protolith. The fault core tends to decrease permeability, whereas the damage zone enhances permeability. The net effect is an anisotropic permeability structure as illustrated by the ellipsoid in Figure 1.2; permeability will be higher along the fault plane than across it. The degree of anisotropy will be a function of the relative development of the core and damage zone of the fault, as illustrated in Figure 1.3.

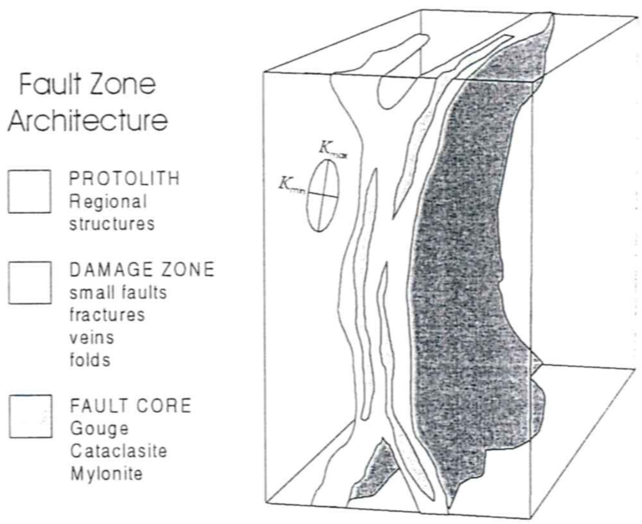


Figure 1.2 Schematic model of fault zone architecture illustrating a low peremability core zone surrounded by a high permeability damage zone that create an anisotropic permeability structure favoring fluid flow along the fault plane (after Caine et al., 1996).

Many Springs occur along the trace of the McConnell Thrust (K-Ar age of illite/smectite in the fault gouge gives 77 Ma as the main deformation age (Covey et al., 1994). The McConnell fault zone is characterised by a fault core 40 to 100 cm thick comprised of shale cataclasite and a limestone mylonite. There is an extensive damage zone for meters above and below the core that is characterised by mesoscopic fracture and fault arrays and folds (Kennedy and Logan, 1997). Relating these characteristics to Figure 1.3 we see that the McConnell Thrust Fault falls into the combined conduit/barrier category. These fault types are the most effective in developing spring systems as they inhibit fluid flow across the fault and focus it along the fault. In Figure 1.1 we see that the McConnell thrust captures water infiltrating from topographic highs above the fault, which then is focused to discharge areas where the fault crops out in the valley. Thus, a major control on the depth to which water circulates in a spring system is the depth at which the fault occurs beneath the recharge area (Grasby and Hutcheon, in review). In the case of Many Springs the shallow dipping McConnell Thrust restricts circulation depths to 600 m, and thus restricts the temperature of the springs to a relatively cool 11 °C.

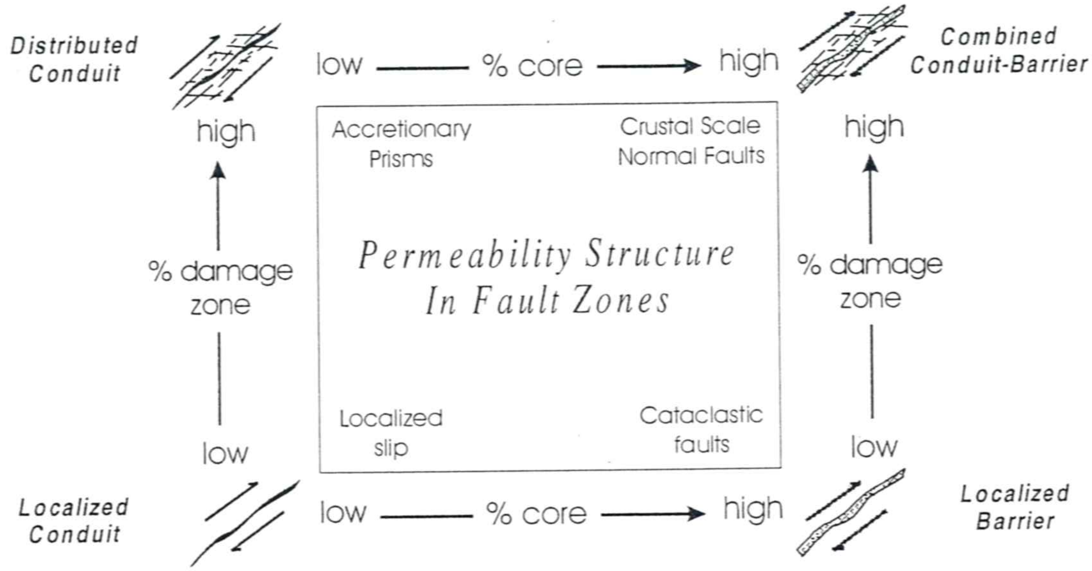


Figure 1.3 Classification scheme for the permeability structure of faults based on the relative intensity of the core and damage zones that are developed (after Caine et al., 1996).

References

Caine, J.S., Evans, J.P., and Forster, C.B. (1996) Fault zone architecture and permeability structure. Geology, **24**, 1025-1028.

Covey, M.C., Vrolijk, P.J., and Pevear, D.R. (1994) Direct dating of fault movement in the Rocky Mountain Front Ranges of southern Alberta. Geological Society of America Abstracts with Programs, 26, A467.

Grasby, S.E. and Hutcheon, I. (in review) Controls on the distribution of thermal springs in southern Alberta and British Columbia.

Kennedy, L.A. and Logan, J.M. (1997) The role of veining and dissolution in the evolution of fine-grained mylonites: the McConnell thrust, Alberta. Journal of structural geology, **19**, 785-797.

The stratigraphic section preserved along Jura Creek (Figure 2.1) includes the upper portions of the Devonian Palliser Formation, the type section of the Devonian-Mississippian Exshaw Formation and the lowermost beds of the Mississippian Banff Formation. This section lies within the McConnell thrust sheet (Figure 2.2), which constitutes the easternmost thrust sheet of the Rocky Mountains Front Ranges.

Stratigraphy

At the type section of the Exshaw Formation at Jura Creek, two members are recognized (Figures 2.3, 2.4). The Black Shale Member is 9.5 m thick, and comprises black, organic-rich, laminated, pyritic shales. The Black Shale Member is further subdivided into a 1 to 6 cm thick basal sandstone and conglomerate bed, a noncalcareous to slightly calcareous lower shale unit and a calcareous upper shale unit. The contact between the Black Shale Member of the Exshaw Formation and the underlying Palliser Formation is probably disconformable at Jura Creek, however the hiatus is believed to be minor, as no conodont zones are missing across the boundary, nor is there any substantial evidence for erosion or subaerial exposure at the contact (Richards et al., 1991).

The Siltstone Member of the Exshaw Formation comprises partly bioturbated, orange-brown weathering siltstone and silty limestone. At Jura Creek, the Upper Member is approximately 38 m thick, however substantial thinning of this unit occurs just one thrust sheet west (section A on Figure 2.2), where it is only about 13 m thick. This thinning is accompanied by thickening of the overlying basal shale (Member A) of the Banff Formation, which is <1 m thick at the Jura Creek locality, but is about 10 m thick in the Exshaw thrust sheet.

The contact between the siltstones of the Upper Member of the Exshaw and the basal shales of the Banff Formation is abrupt and slightly undulous at this exposure, and may be disconformable, however sedimentological evidence for substantial erosion is absent (Richards et al., 1991).

The cross-section shown in Figure 2.5 illustrates the relationships between outcrops of the Devonian-Mississippian section with occurrences of these units to the east, in the subsurface. From this figure, one can observe the dramatic thinning of the Mississippian section from west to east. This thinning is partly depositional, but the most significant thickness losses occur in response to sub-Jurassic and sub-Cretaceous erosion. It is also clear from this figure that the Black Shale Member of the Exshaw Formation is recognized by a high gamma ray log response, which permits easy identification of this unit in the subsurface. The Exshaw-Banff stratigraphy observed at Jura Creek is carried eastward until the axis of the Sweetgrass Arch is reached. The Sweetgrass Arch represents the approximate boundary between the Alberta Basin to the west, and the Williston Basin to the east. In the Williston Basin (at approximately 8-19-26-8W4 on Figure 2.5), the two members of the Exshaw Formation, and Member A of the Banff Formation are included in the Bakken Formation. The beds overlying the Bakken are referred to as the Lodgepole Formation.

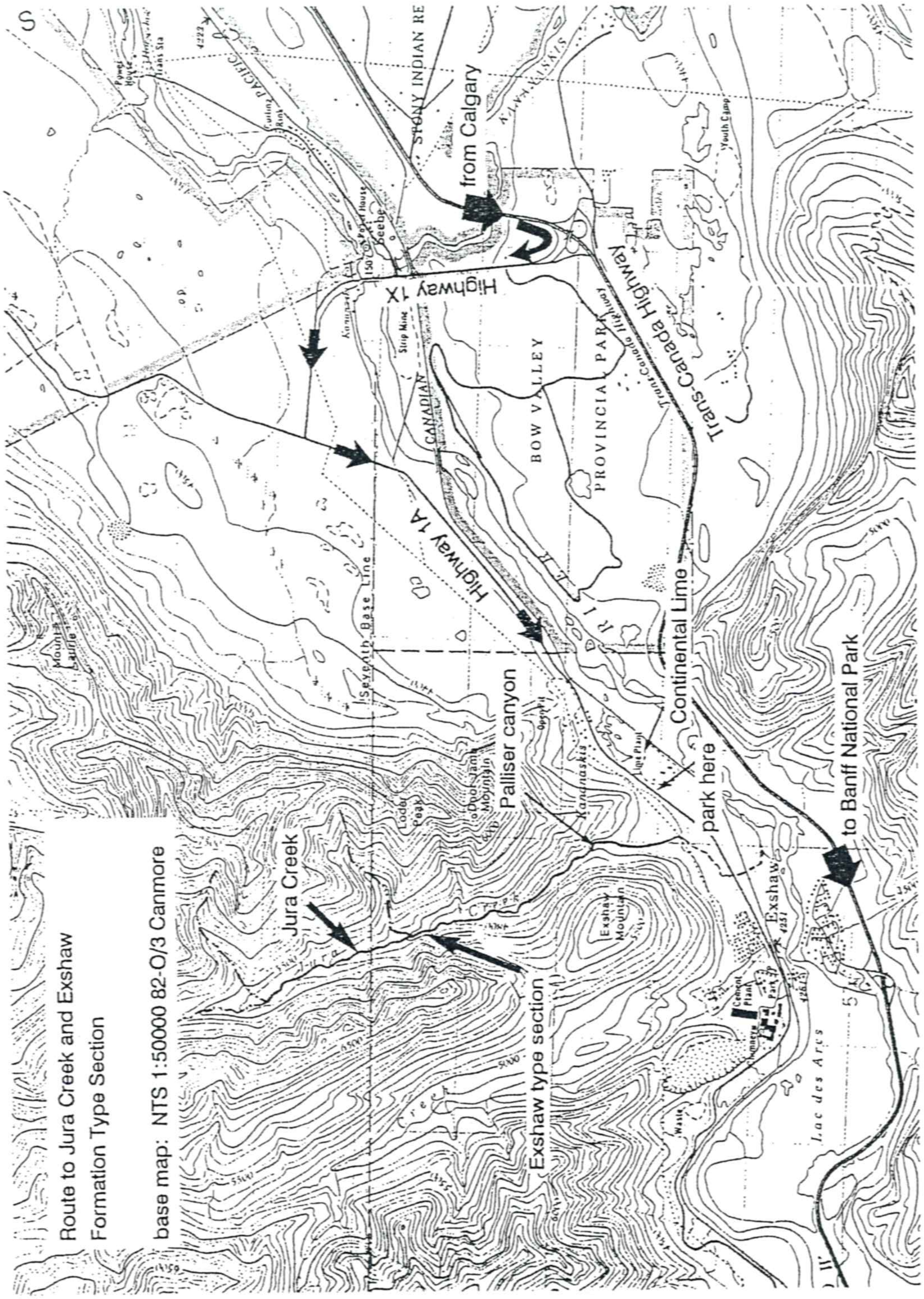
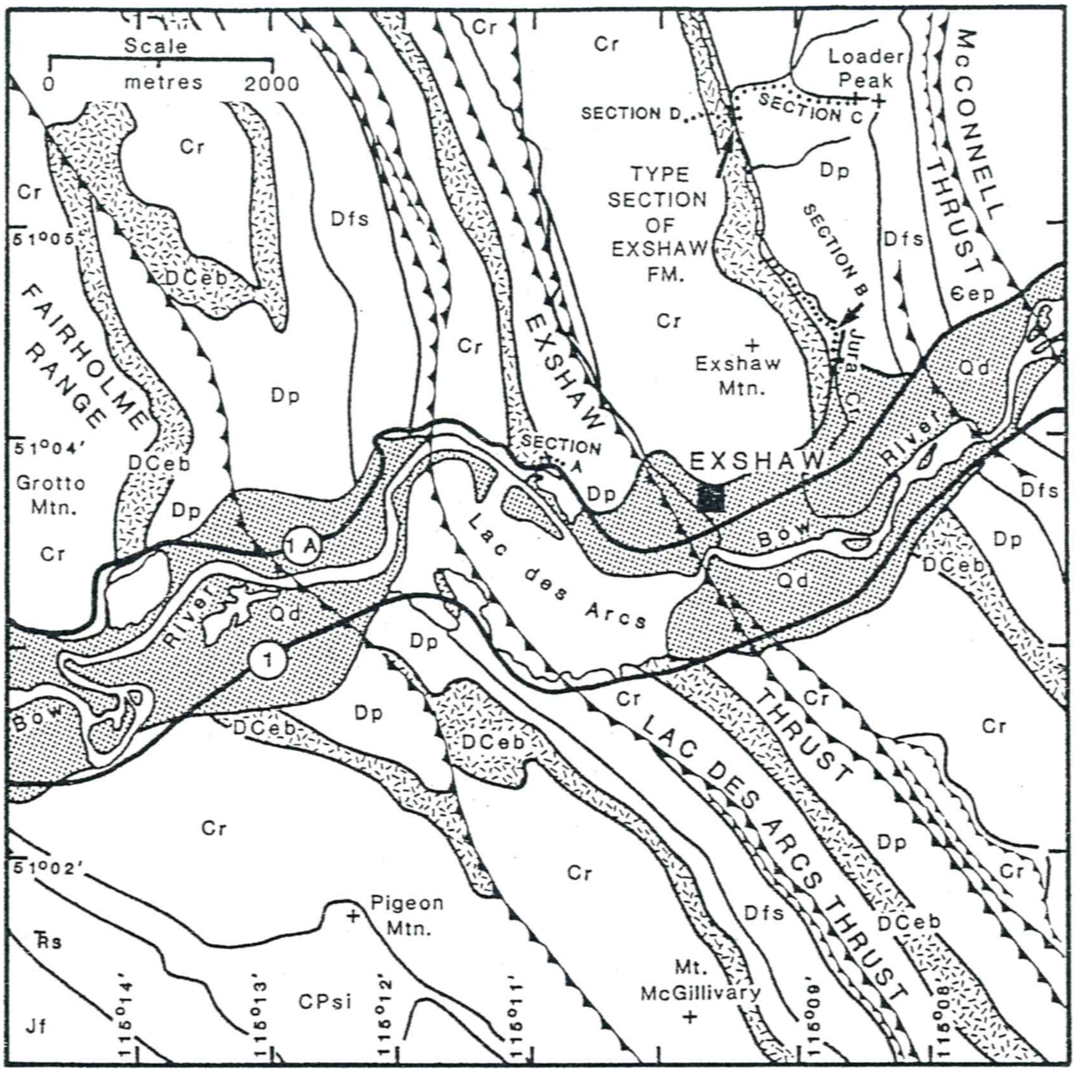


Figure 2.1 Location of the Exshaw Formation type section at Jura Creek (Figure courtesy of Jon Greggs, University of Calgary).



LEGEND

QUATERNARY

Qd Gravel, silt, and sand

JURASSIC

Jf Fernie Gp.

TRIASSIC

Ꞓs Spray River Gp.

CARBONIFEROUS AND PERMIAN

CPsi Spray Lakes and Ishbel Gps.

CARBONIFEROUS

Cr Rundle Gp.

DEVONIAN AND CARBONIFEROUS

DCeb Exshaw and Banff Fms.

DEVONIAN

Dp Palliser Fm.

Dfs Fairholme Gp. and Sassenach Fm.

CAMBRIAN

Ꞓep Eldon and Pika Fms.

Thrust fault

Line of section

Figure 2.2 Generalized geological map of the Jura Creek region, eastern Rocky Mountain Front Ranges, southwestern Alberta (modified from Richards et al., 1991).

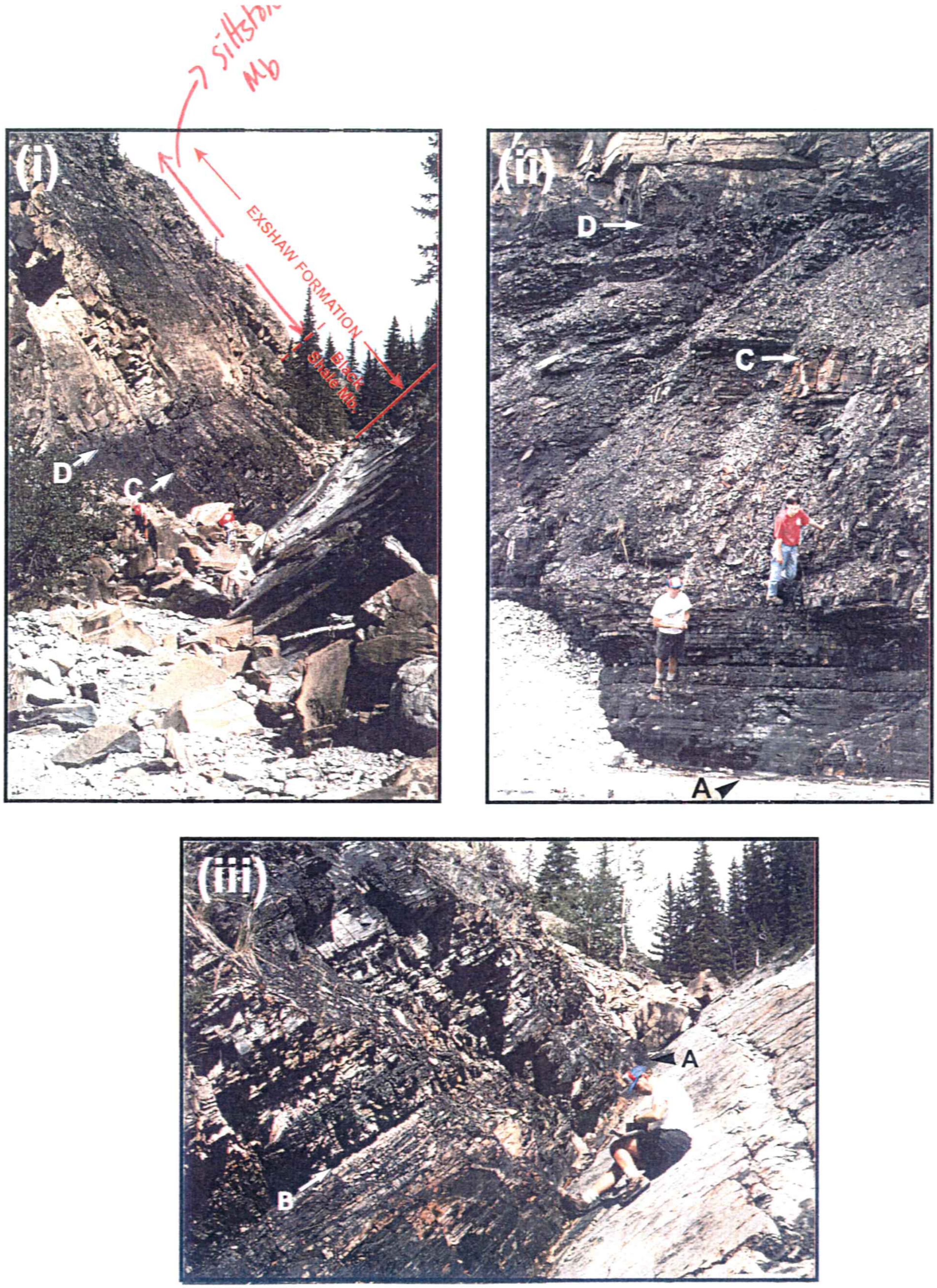


Figure 2.3 Photographs of the Exshaw Formation at Jura Creek. (i) View of the uppermost Palliser and Exshaw formations. People (about 1.8 m tall) for scale. (ii) Close-up view of the Black Shale Member. People (about 1.8 m tall) for scale. (iii) Close-up view of the basal contact of the Exshaw Formation. A= disconformable base of the Exshaw Formation; B = thin (1-2 cm) tuff bed; C = contact between the lower and upper shale units (Black Shale Member), and approximate location of the Devonian-Mississippian boundary; D = gradational contact between the Black Shale Member and the Siltstone Member.

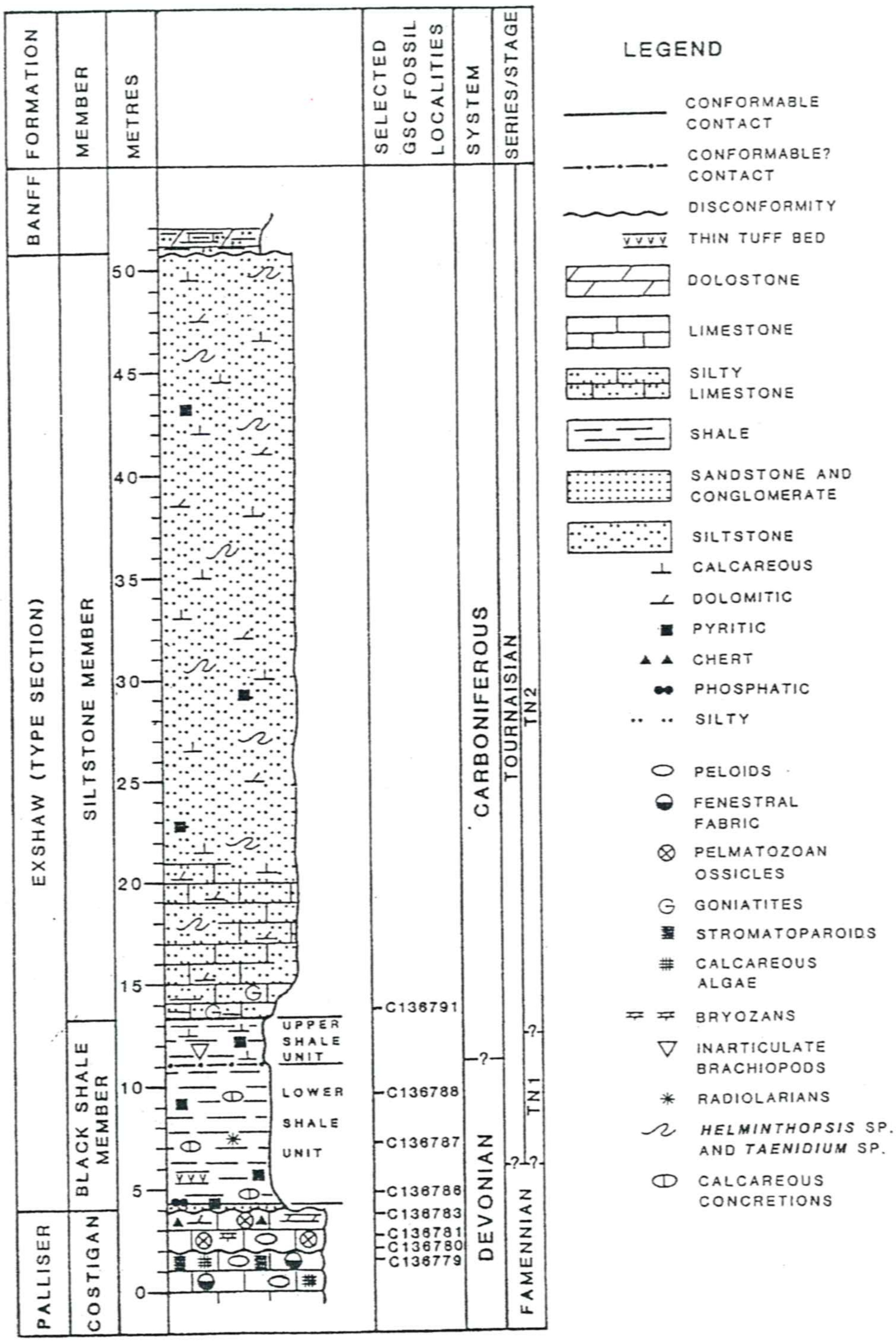


Figure 2.4 Columnar section of uppermost Palliser, Exshaw and basal Banff formations, at Jura Creek (from Richards et la., 1991).

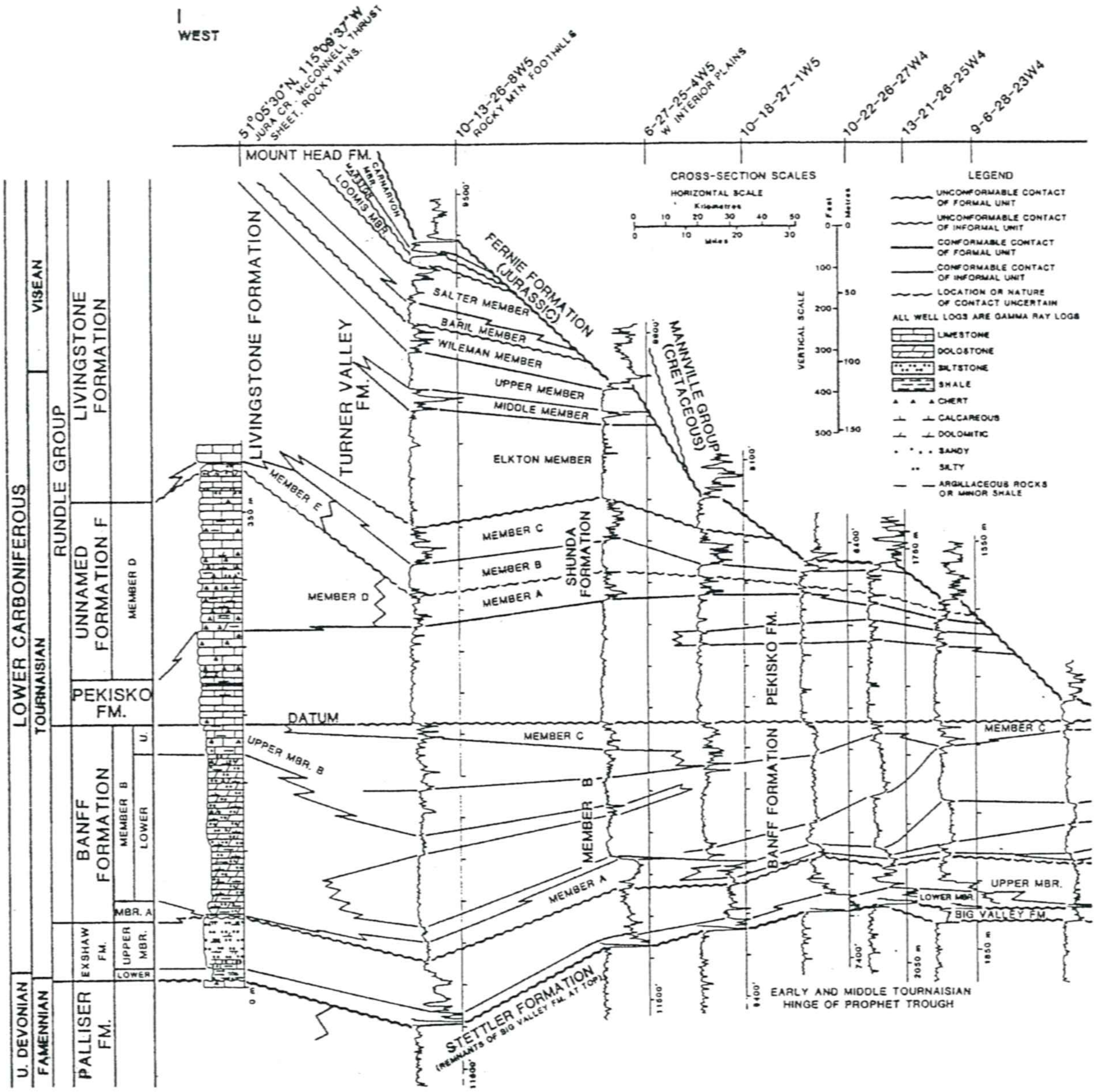


Figure 2.5 Palinspastic, east-west stratigraphic cross-section from Jura Creek to eastern Saskatchewan, showing the uppermost Devonian and Carboniferous succession (modified from Richard et al., 1991).

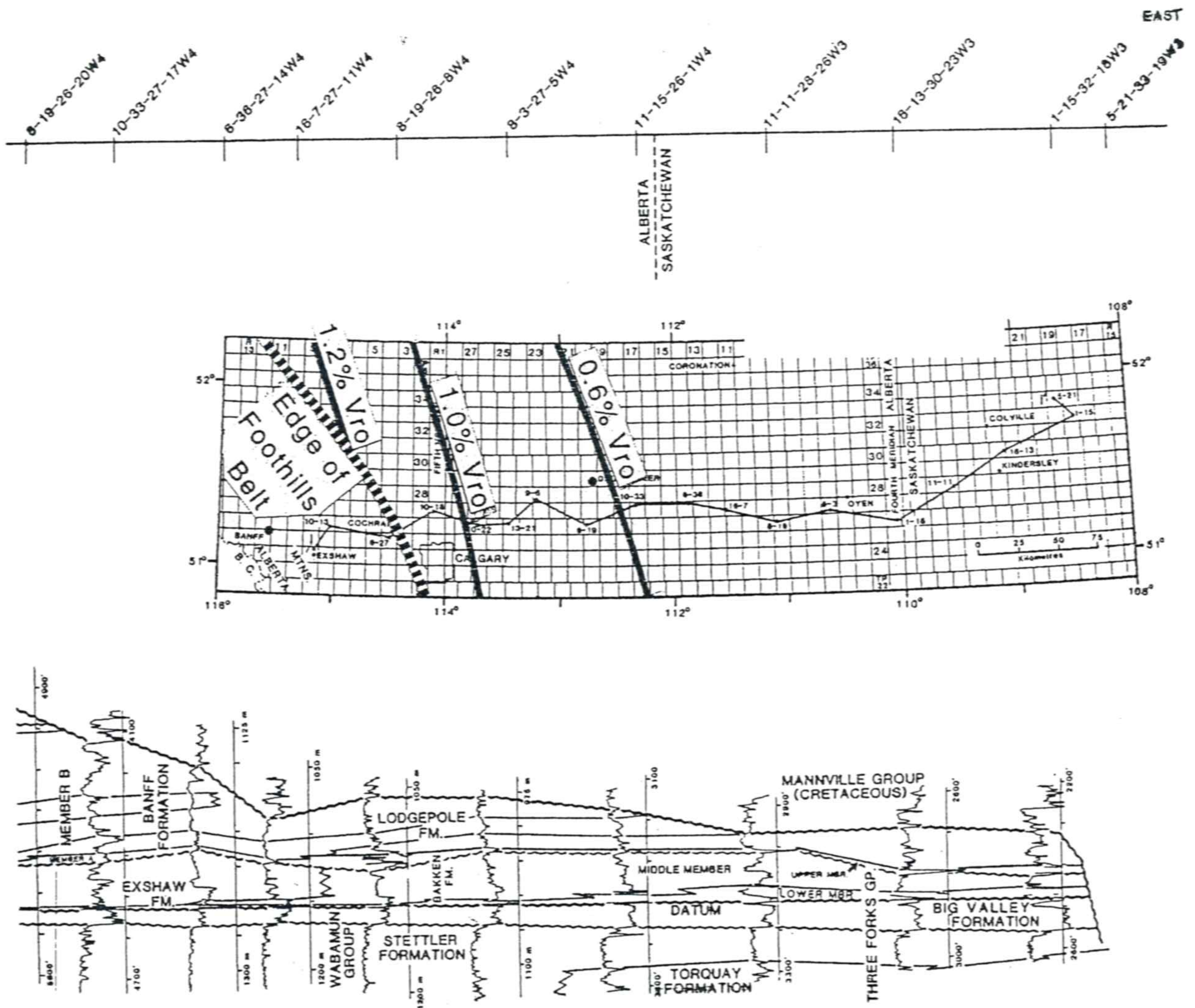


Figure 2.5 (continued). Palinspastic, east-west stratigraphic cross-section from Jura Creek to eastern Saskatchewan, showing the uppermost Devonian and Carboniferous succession (modified from Richard et al., 1991). Vitrinite reflectance contours are shown on the inset map, and indicate increasing maturity from east to west (data from L. Stasiuk, personal communication).

Age

The age of the Exshaw Formation is Devonian (Famennian) to Mississippian (Tournaisian), based on conodont identifications (Richards et al., 1991). The D-C boundary (353 Ma) occurs within the Black Shale Member of the Exshaw Formation (marked "C" on Figure 2.3). Ross and Parrish (unpublished) sampled the tuffs near the base of the Exshaw Formation ("B" on Figure 2.3), and determined an age of 363-364 Ma (Famennian) based on U-Pb dating of zircons in the tuff. The radiometric age thus supports the age assigned based on conodont biostratigraphy.

Geochemistry

The Exshaw Formation at Jura Creek was sampled and analysed on a Rock-Eval II/TOC pyrolysis unit to determine its hydrocarbon source rock character and total organic carbon content (Riediger and Fowler, 1994, unpublished). The sample locations are shown in Figure 2.6, and Rock-Eval/TOC results are provided in Table 2.1. These data indicate that the Exshaw is overmature with respect to hydrocarbon generation at Jura Creek (Hydrogen Index values close to zero, no measurable Tmax), however generally high TOC values (up to 5 wt. % near the base of the Lower Member) suggest an initially highly organic-rich rock. The vertical trend of TOC values (Figure 2.7) illustrates that the richest beds occur near the base of the Lower Member, and decrease upwards to values less than 1% just below the transition beds with the Upper Member.

The thermal maturity of the Exshaw decreases westward, passing from a mature region in the west to an immature region east of Calgary, as indicated along the line of section shown in Figure 2.5. In the immature regions of the basin, TOC's for the Exshaw range up to 14 wt. %, and HI values vary up to 550 mg hydrocarbon/g TOC (Riediger, unpublished data). These data suggest that the Exshaw Formation contains marine, Type II kerogen.

Oil-source rock correlations, based on biomarker analyses of oils and source rock extracts, have shown that the Exshaw is the source for many oil accumulations in southern Alberta, with significant contributions to Lower Mannville reservoirs (Karavas, et al., 1998; Riediger et al., 1999). Exshaw oils have migrated as much as 450 km from mature source rocks in southwestern Alberta, to fields in eastern Alberta (e.g. Provost field). 1-D basin modeling studies (e.g. Ardic, 1998; N.T. Akpulat, unpublished results) suggest that hydrocarbon generation from the Exshaw in southern Alberta commenced in latest Cretaceous to Paleocene time, during the Laramide orogeny (see Figure 14.4).

Depositional Environment and Tectonic Setting

The sedimentology and geochemistry of the Lower Member of the Exshaw Formation suggests shale deposition under anoxic to euxinic bottom waters in a basinal (deep water) setting. The abrupt change from platformal carbonates of the Palliser Formation to the presumably deep water, euxinic conditions of the Exshaw Formation has long intrigued geologists hoping to explain this phenomenon. Any model proposed to account for this transition (e.g. Savoy, 1992; Caplan et al., 1996) must explain not only local occurrences of this boundary, but also the fact that this abrupt transition occurs in both cratonic margins and cratonic interiors of North America. A rapid eustatic sea level rise is commonly proposed to account for this phenomenon, however Bond and Kominz (1991) argue that this sea level rise is insufficient to account for the amount of subsidence in the cratonic margins and interiors, and that synchronous tectonic

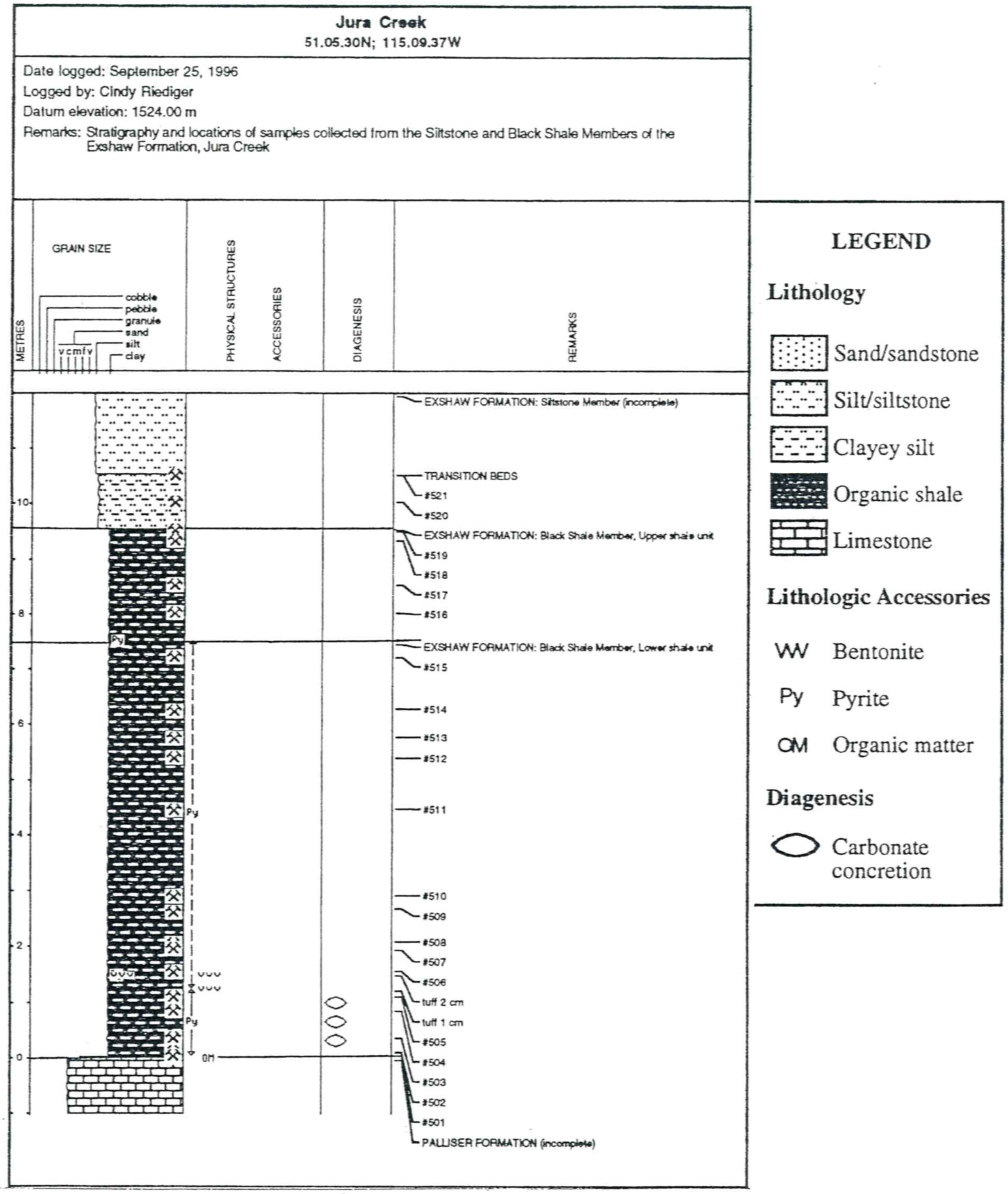


Figure 2.6 Stratigraphic section through the Black Shale Member of the Exshaw Formation at Jura Creek, showing the locations of samples collected for Rock-Eval/TOC analysis.

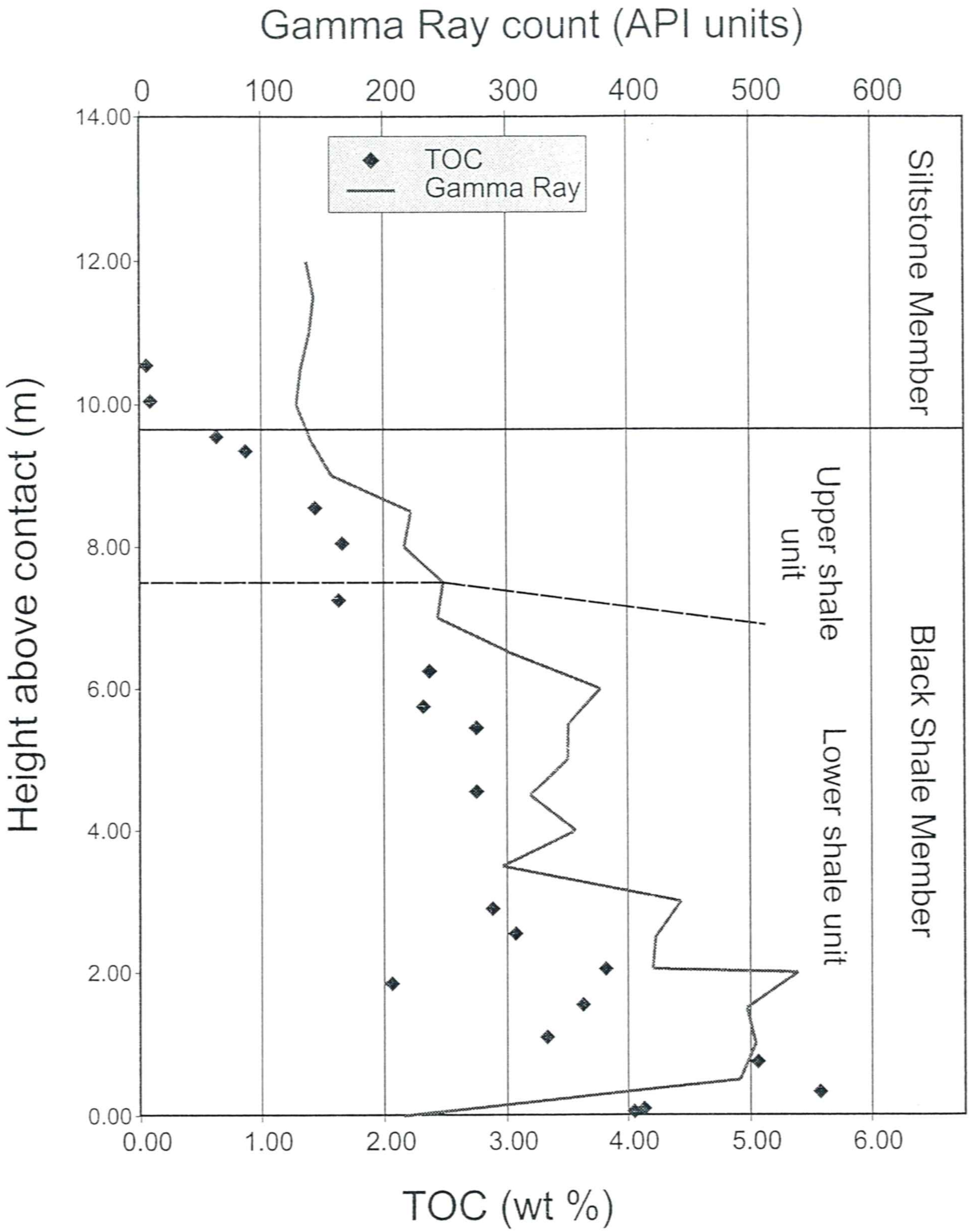


Figure 2.7 TOC values and Gamma Ray curve, Exshaw Formation, Jura Creek (Gamma ray data courtesy of Silas Ehlers)

Table 2.1 Exshaw Type section at Jura Creek, 51°05'30"N; 115°09'37"W

metres above base	Sample no.	unit	TOC (%)	S1	S2	S3	PI (S1/S1+S2)	HI	OI	Tmax (°C)
0.03	501	Lower Sh	4.05	0.00	0.14	0.12	0.00	3	3	N/A.
0.07	502	Lower Sh	4.13	0.01	0.15	0.05	0.06	4	1	N/A.
0.33	503	Lower Sh	5.57	0.01	0.18	0.13	0.05	3	2	N/A.
0.73-0.83	504	Lower Sh	5.06	0.01	0.04	0.18	0.20	1	4	N/A.
1.03-1.13	505	Lower Sh	3.33	0.00	0.03	0.28	0.00	1	8	N/A.
1.55	506	Lower Sh	3.63	0.00	0.05	0.19	0.00	1	5	N/A.
1.85	507	Lower Sh	2.06	0.00	0.07	0.37	0.00	3	18	N/A.
2.05	508	Lower Sh	3.82	0.00	0.02	0.23	0.00	1	6	N/A.
2.55	509	Lower Sh	3.07	0.00	0.06	0.23	0.00	2	7	N/A.
2.9	510	Lower Sh	2.88	0.00	0.03	0.50	0.00	1	17	N/A.
4.55	511	Lower Sh	2.75	0.00	0.06	0.18	0.00	2	7	N/A.
5.45	512	Lower Sh	2.75	0.00	0.04	0.26	0.00	1	9	N/A.
5.75	513	Lower Sh	2.32	0.00	0.01	0.19	0.00	0	8	N/A.
6.25	514	Lower Sh	2.37	0.00	0.06	0.29	0.00	3	12	N/A.
7.25	515	Lower Sh	1.63	0.00	0.02	0.67	0.00	1	41	N/A.
8.05	516	Upper Sh	1.66	0.00	0.02	0.44	0.00	1	27	N/A.
8.55	517	Upper Sh	1.44	0.00	0.00	0.51	0.00	0	35	N/A.
9.35	518	Transition beds	0.87	0.00	0.02	0.20	0.00	2	23	N/A.
9.55	519	Transition beds	0.63	0.00	0.06	0.26	0.00	10	41	N/A.
10.05	520	Transition beds	0.08	0.00	0.00	0.20	0.00	0	250	N/A.
10.55	521	Siltstone Mbr.	0.05	0.00	0.00	0.19	0.00	0	380	N/A.

subsidence is also required. Such a model requires a mechanism for producing tectonic subsidence in both marginal and basinal settings around North America. Bond and Kominz (1991) suggest that a pulse of intraplate stress could account for the tectonic subsidence, and argue that this hypothesis is consistent with recent mantle convection models for the early stages of accretion of supercontinents.

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STOPS 3 & 4– SULPHUR MOUNTAIN HOT SPRINGS S. Grasby

"A peculiarity in connection with the sulphur water is that it cannot be very well mixed with other liquids; particularly does this apply to scotch."

An early guide book

The hot springs along Sulphur Mountain Thrust, near the town of Banff, were discovered by surveyors for the Canadian Pacific Railway in 1883. Ensuing legal conflicts over ownership brought attention to the site that ultimately led to the creation of Canada's first national park. Nine thermal springs, in three groups, occur in a linear trend along the Sulphur Mountain Thrust (Fig. 3.1). The three groups of springs occur at progressively lower elevations descending towards the Bow Valley. The highest group includes the Upper Hot Spring (1584 m) and the Kidney Spring (26 m lower, and about 180 m from the Upper Hot Spring). The Upper Hot Spring (Stop 4) feeds the public swimming pool. A group of three springs, commonly referred to as the Middle Springs, issue from small caves at approximately 1500 m. The third group, the Cave and Basin Springs, occur just south of the Bow River at 1400 m. The Cave Spring (Stop 3) discharges into a circular cave 12 m in diameter and 6 m high. The cave walls are coated with deposits of calcite and gypsum. Stalactites that once occurred in the cave have either been removed or destroyed. The Basin Spring rises in an artificial pool just west of the cave. Two additional springs (Upper and Lower C&B) occur immediately above the Cave Spring (keep an eye out for the tropical fish living in the warm waters of the pools). In addition to the thermal springs along Sulphur Mountain, warm springs occur at Vermilion Lake and 40 Mile Creek (Fig. 3.1). A spring that occurred at the base of Stoney Squaw Mountain was buried by construction of the Banff interchange. Several cool sulphurous springs also occur in the vicinity.

Temperatures of the sulphurous springs in the Banff area vary from 6 to 47 °C, with the springs along Sulphur Mountain having the highest temperatures (27 to 47 °C). Discharge rates range from 91 l/min at the Kidney Spring to 1136 l/min for the Cave Spring (van Everdingen, 1972). The Upper Hot Spring and Basin Spring have been developed into swimming facilities, although only the Upper Hot Spring remains in use. The Middle Springs are largely in a natural state and are now closed to the public as they fall in the Sulphur Mountain wildlife corridor. Where undisturbed, discharge pools of the thermal springs are characterised by growths of cyanobacteria as well as a white filamentous-bacteria (*Thiothrix*). A unique species of snail (*Physella johnsoni,* Fig. 3.2) that only lives in the Banff Hot Springs, can be found feeding on the bacteria mats.

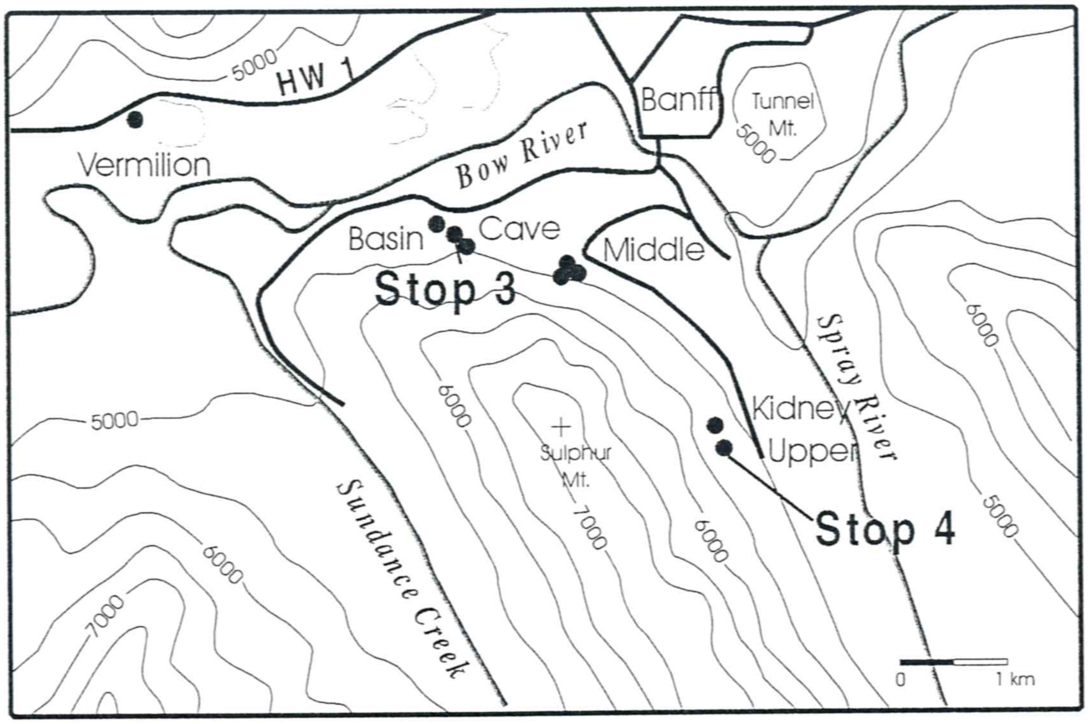

Figure 3.1 Location map of the thermal springs (dots) and field stops in the Sulphur Mountain area.

Water Chemistry

An interesting feature of the springs at Sulphur Mountain is the consistency in water chemistry. The major ion chemistry of the spring waters spanning from 1917 to 1994 are plotted in Figure 3.3, illustrating the similarity through time, and between springs, of major ion ratios. The largest variation in Figure 3.3 is the relative amounts of HCO_3 and SO_4. Figure 3.4 plots SO_4/HCO_3 versus TDS, for springs from 1917 to 1994, as well as the average composition of shallow ground water in the Banff area. This shows that the variations in chemistry observed through time, and between the different springs, may be explained by a simple mixing relationship between the sulphur rich, high TDS, thermal fluids and dilute HCO_3-rich shallow groundwater. This is best illustrated by van Everdingen (1970), who collected samples from the Kidney Spring from October 1968 to October 1969. Discharge of this spring is characterized by having constant physical and chemical properties through the fall and winter, when temperatures are highest and flow rates are lowest. For a 6 to 9 week period (from late May to early August), during snowmelt and heavy spring rains, discharge increases and temperatures drop by as much as 10 °C (Fig. 3.5). In contrast to normal flow, this low temperature period is characterised by a drop in total dissolved solids (TDS), the presence of O_2, the absence of H_2S, and higher flow rates (Fig. 3.5). Interestingly, van Everdingen (1970) notes that, as the waters change from reducing to oxidizing conditions, normally prolific colonies of bacteria at the spring site disappear. These colonies do not re-establish themselves until the waters return to a reduced state in early August.

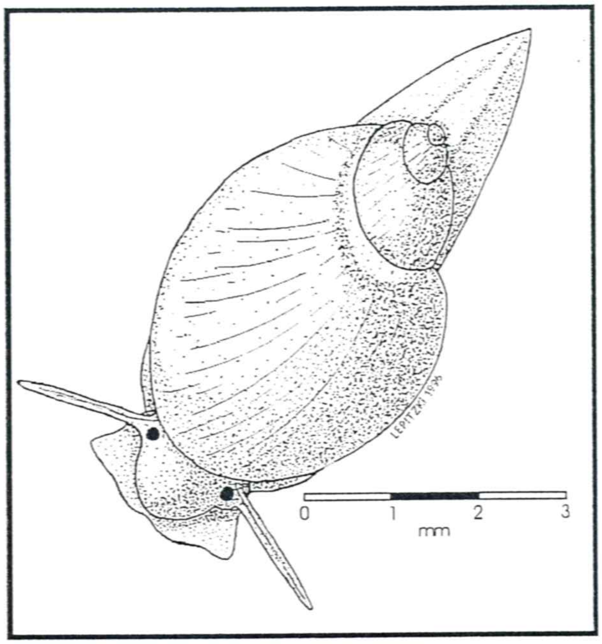

Figure 3.2. Line drawing *Physella johnson* (from Lepitzki, 1997). The only place in the world these snails have been found is in the Banff Hot Springs and they are listed as a threatened species. They appear to be related to more common snails in the area, but have adapted to the warm waters of the springs. They are not found in waters cooler than 30 °C. DNA evidence suggests an evolutionary split around 10,000 years ago, shortly after deglaciation (D. Lepitzki, 1999 – personal com.).

Why Do They Stink? - The Sulphur Cycle

Sulphur occurs as both SO_4 and HS^- in the springs. The smell of sulphur is from the H_2S gas being released. The stable isotope values of SO_4, HS^- and total S for the springs are plotted in Figure 3.6. All springs have $\delta^{34}S$ values for total S around +27‰. These values are consistent with values obtained from Devonian evaporite minerals, gypsum ($CaSO_4{\bullet}2H_2O$) and anhydrite ($CaSO_4$) (Claypool et al. 1980), indicating that dissolution of these minerals from Devonian rocks in the hanging wall (Fig. 3.7) is the primary source of S in the springs. Figure 3.6 also illustrates that the $\delta^{34}S$ values for HS^- are around 25‰ lower than SO_4. Krouse et al. (1970) conclude that the difference in isotope values of SO_4 and HS^- is due to kinetic isotope effects during bacterial sulphate reduction (BSR). In the anaerobic conditions of the subsurface, sulphate reducing bacteria strip the oxygen from SO_4 for use in metabolic processes. The by-product is the H_2S you smell. The most prominent microorganisms in sulphurous springs, including those at Sulphur Mountain, are *Desulfovibrio* and *Clostridium* species. Laboratory experiments by Smejkal et al. (1971) separated two *Clostridium* cultures (their A and B) that appear to reduce SO_4 to H_2S symbiotically. This is based on observations that pure cultures of B could not reduce SO_4^{2-} to HS^-, but could reduce SO_3^{2-}. Whereas pure cultures of A could not reduce SO_4^{2-} or SO_3^{2-} to HS^-. However a mixture of A and B can reduce SO_4^{2-} to HS^-. It is apparent from work by Smejkal et al. (1971) that bacteria play a complex role in the S cycle of thermal springs.

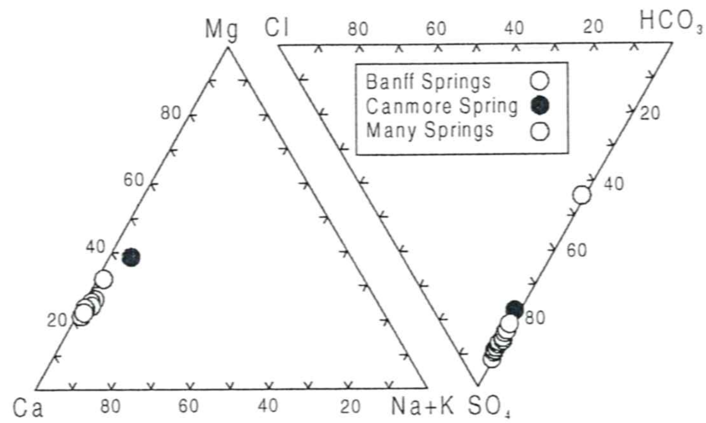

Figure 3.3 Ternary plot, in meq/l, of springs from the Bow Valley area. Data include samples from 1917 to 1994.

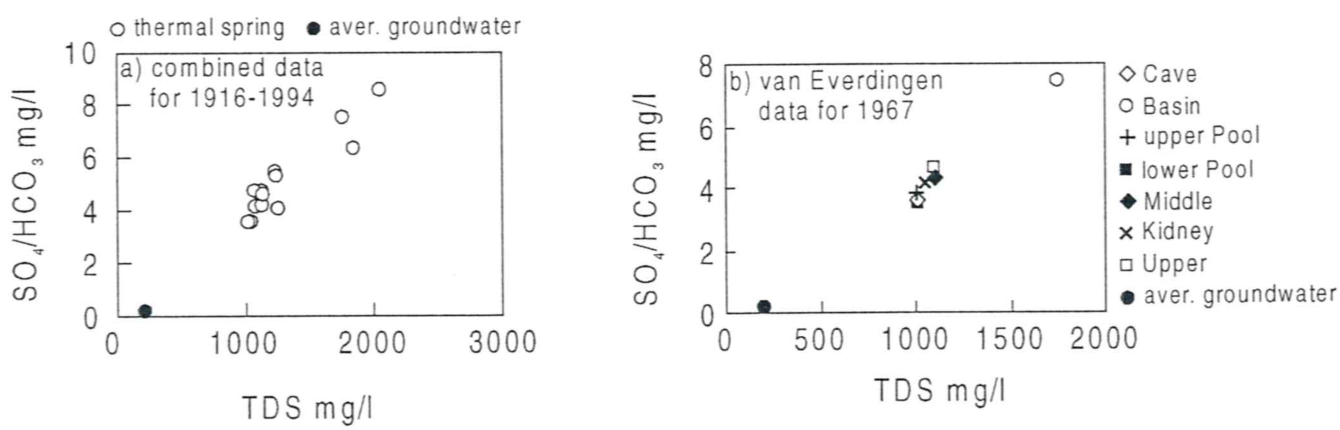

Figure 3.4 Plot of SO_4/HCO_3 ratio for a) springs in the Bow Valley area, covering the period from 1917 to 1994, and b) springs in the Banff area for October 1967. Both plots show that variations in the SO_4 concentration is largely a function of mixing with thermal fluids with shallow ground water (solid circle).

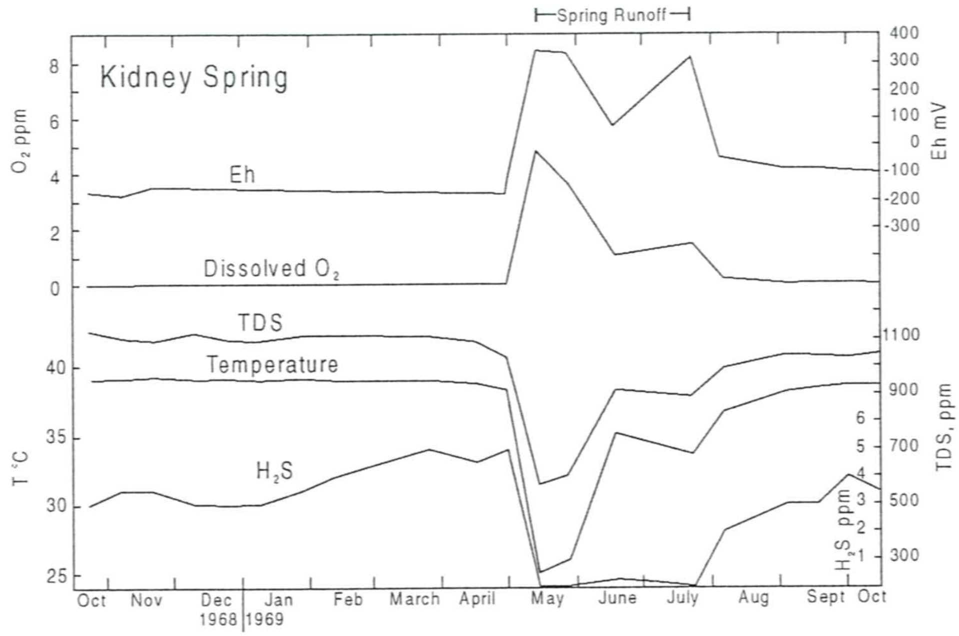

Figure 3.5 Seasonal variation in chemical and physical properties of the Kidney spring (from van Everdingen, 1970).

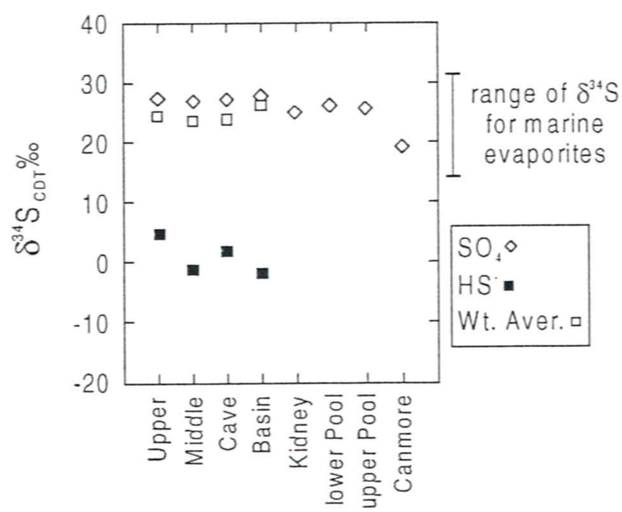

Figure 3.6 $\delta^{34}S$ values for dissolved sulphate, sulphide and weighted average for the Banff springs.

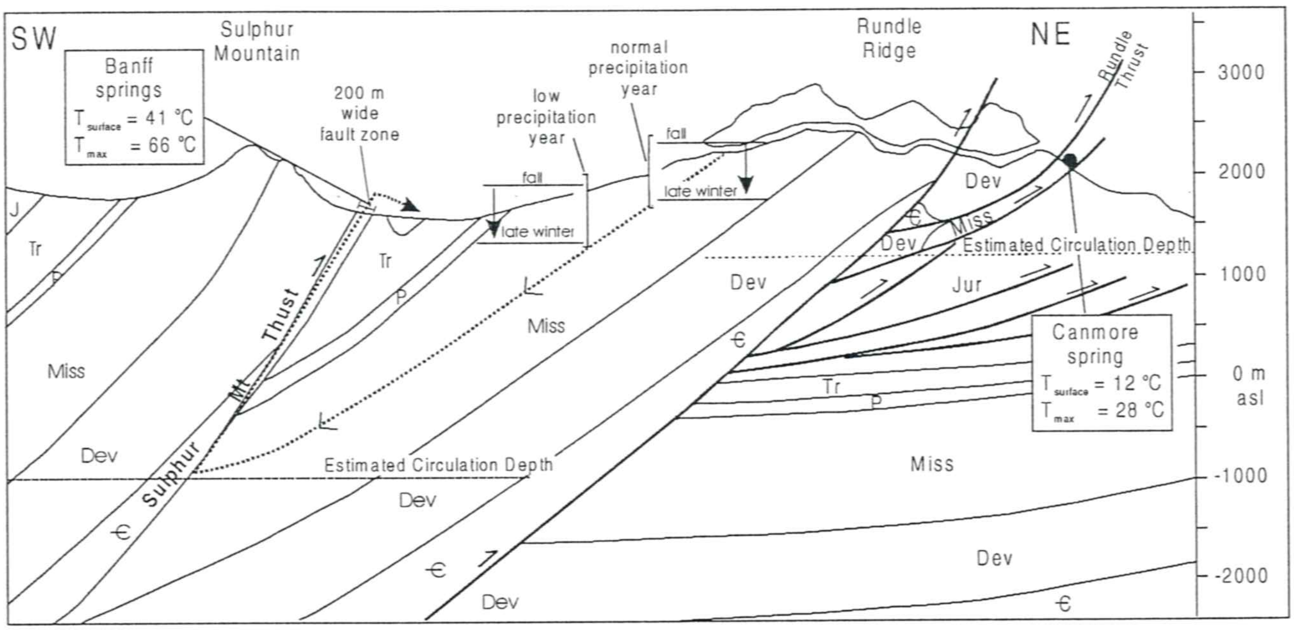

Figure 3.7 Cross-section through Sulphur Mt. And Mt. Rundle (after Price and Mountjoy, 1972) with estimated circulation depth indicated. Thermal spring systems at Banff and Canmore are indicated.

Gas Chemistry

The springs examined here discharge gas as well as water; generally as intermittent bubbles from the main outlets. Gases collected from various springs (Elworthy, 1926) are composed of 96.6 to 98.2% N_2, with the remainder being largely CO_2, CH_4 and He. The atmosphere is dominantly N_2 (80%) and O_2 (20%). Thus, the abundance of N_2 in the spring discharge suggests that atmospheric gas is trapped in the recharge area, after which O_2 is consumed by redox reactions, leaving essentially pure N_2. This is supported by noble gas concentration patterns that are similar to those for air-saturated water (ASW) at representative temperature (5 °C) and altitude (1700m) for the springs (Fig. 3.8) (Mazor et al., 1983). The enriched He concentrations are likely related to α-decay of radioactive minerals along the flow path.

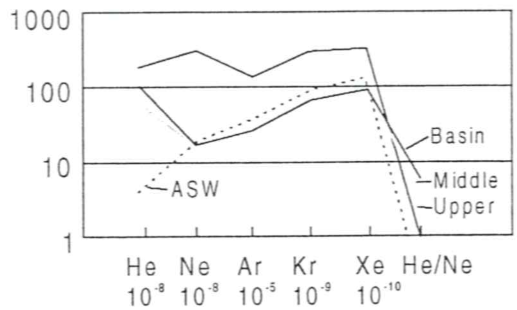

Figure 3.8 Noble gas concentration patterns for springs near Banff (after Mazor et al., 1983).

Hydrogeology of the Bow Valley Springs

In order to examine the hydrogeology of these springs, it is important to know the source of the water. Grasby et al. (2000) show stable isotope data that indicate that the spring water originates as rain and snow fall. Thus the hydrology of these springs is characterized by meteoric water circulating to depth, being heated, and then circulating back to surface. Differences in surface temperature are a function of the degree of mixing with shallow groundwater, as well as circulation depth. It is possible to estimate the circulation depth of meteoric waters using local geothermal gradients in conjunction with water temperatures.

Circulation Depth

Since water cools on ascent, the measured surface temperature does not give an accurate estimate of depth. Due to high Ca concentrations, precipitation of Ca minerals at surface, and relatively low temperatures (< 180 °C), the chalcedony geothermometer (Arnorsson, 1975) provides the most reasonable temperatures for the Banff springs. The geothermometer is based on the relationship of Si concentration in water to temperature, by equilibrium with chalcedony (a silica polymorph):

$$T^{\circ}C= (1032/(4.69\text{-}\log SiO_2))-273.15 \qquad (1)$$

While relatively quick to dissolve with increasing temperature, chalcedony is slow to precipitate due to kinetic barriers as temperature drops. Thus, as the water cools on its rise to surface, the Si concentration remains at the level consistent with the highest temperature the water reached. By measuring the concentration of Si, and plugging it into equation 1, the maximum temperature reached along the flow path is calculated. Dilution by ground water, and precipitation of Si would reduce the calculated chalcedony temperature, however there are no artificial means of increasing it. So that the calculated temperature represents a minimum estimate of the highest temperature reached.

In a strong flow system, geothermal gradients are likely perturbed. However, without detailed information about the flow path, it would be difficult to predict accurately the true gradient. Numerical models suggest that if advective heat flow is dominant, the geothermal gradient in the recharge zone will tend to be lowered (Forster and Smith, 1988a,b). Thus, as with potential errors in the chalcedony geothermometers, errors in the geothermal gradient will tend to minimize depth estimates. Therefore, minimum depths of circulation are calculated based on the simplifying assumption that the geothermal gradient is linear with depth and using a gradient of 21 °C/km (Hitchon, 1984). The Upper Hot Spring has the highest chalcedony temperature, 66.5 °C, giving a circulation depth of 3.2 km. Similar to Many Springs (Stop 1), the circulation depth is consistent with the depth of the Sulphur Mountain Thrust beneath the topographic high, suggesting again that the fault plan geometry controls the circulation depth. The reason that thermal springs are only found along this portion of the Sulphur Mountain Thrust is likely related to complex deformation that locally enhances permeability.

As illustrated in Figure 3.9, the Sulphur Mountain Thrust sheet is a relatively uncomplicated homoclinal SW dipping pannel. However unusual transverse structures occur in the vicinity of Banff. A swarm of steeply dipping northeast trending dextral faults with up to 200 m offset cross cut the Sulphur Mountain thrust sheet. Price (in review) indicates that these faults are related to stretching along strike of the Sulphur Mountain thrust sheet in response to the development of a transverse monocline in the underlying Rundle Thrust, as observed in the Cascade Mountain area. The Sulphur Mountain Thrust also shows an anomalous zone of deformation in the Banff area, were the fault goes from a relatively discrete slip plane to a wide zone of deformation, up to 200 m true thickness (Fig. 3.7). This fault zone is bounded by the Sulphur Mountain Thrust proper and a footwall splay (Price and Mountjoy, 1972). Deformation within the fault zone is characterised by complexly faulted and folded Permian and Mississippian strata. Similarly, there is another occurrence of a thermal spring where the Rundle thrust is cut buy a transverse fault in the Canmore area (Fig. 3.9).

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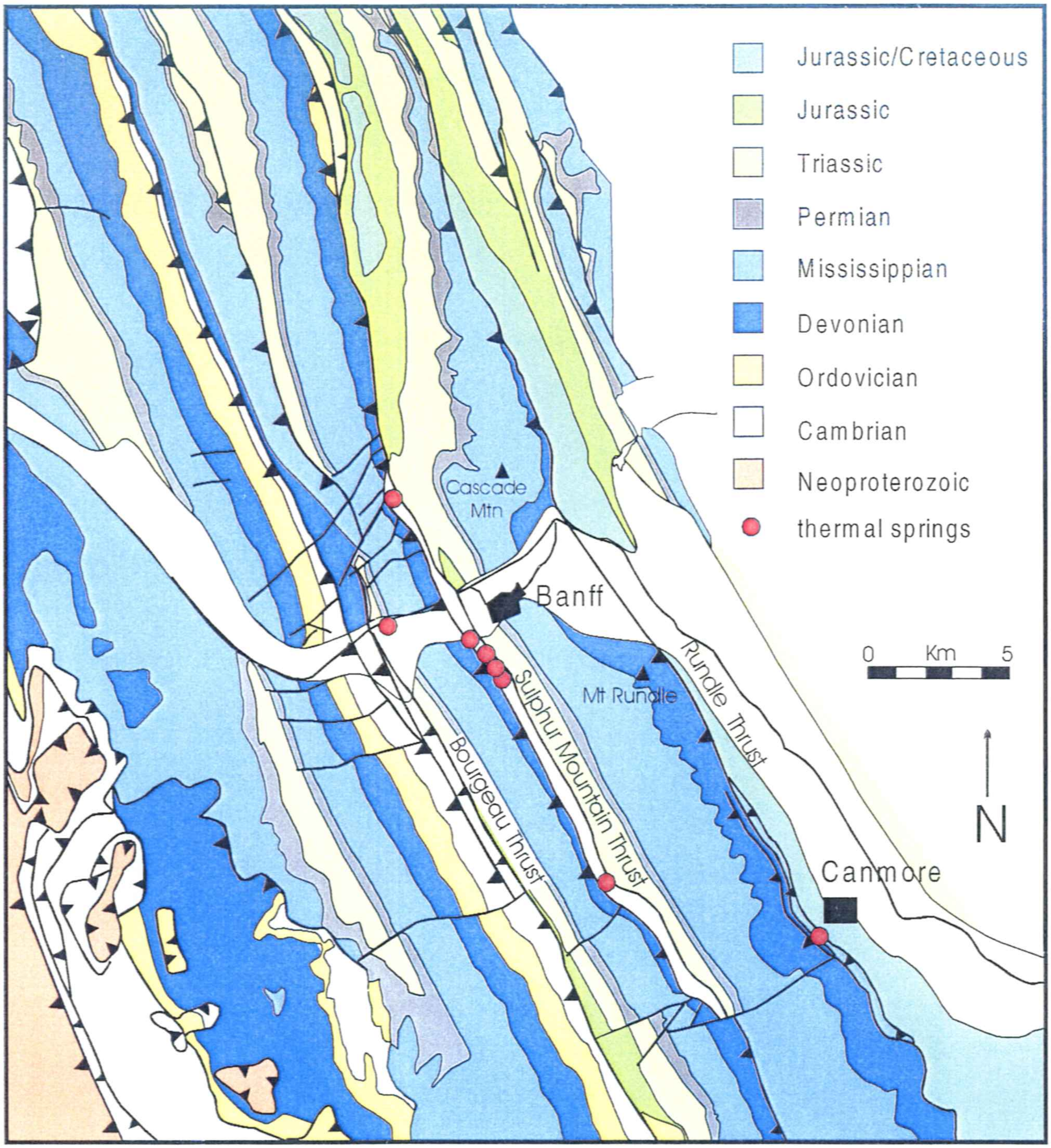

Figure 3.9 Regional geological map of the Banff area illustrating the complex transverse structures in the Banff area (after Price, in press).

Modified and expanded from notes written by Jim Underschultz for the 1997-98 HydroDiv Field Trip "Holes in the Rockies"

Objectives

- Review local geology
- Discuss rock properties: Porosity and permeability
- Introduce calculation of fluid flow: Darcy's Law

Grassi Lakes Geology

The White Man Gap Dam overlooks the town of Canmore in the Bow River valley (Fig. 5.1). The dam is located about halfway up the eroded face of the Rundle thrust sheet, a 2 km thick slab of Cambrian, Devonian and Mississippian carbonates that forms the Rundle Range. The Rundle sheet has been thrust over the Kootnay Formation, a Cretaceous coal-bearing sandstone and shale unit that outcrops in the Bow River valley. The fault plane is the Rundle Thrust, which runs parallel to the Trans Canada highway passing under Rundle Dyke (Fig. 5.1). The Rundle thrust places Cambrian over Cretaceous strata. Across the valley (northeast of Canmore) the section is repeated in the Fairholme thrust sheet. The **GSC Roadside Geology booklet** (Attachment 1) contains a geological map and cross-section C-D of this area.

After examining the Upper Southesk Formation exposure (across the Spray Lakes road opposite the dam top road entrance) we will hike down the dam face to Grassi Lakes. These two small lakes are fed by subsurface discharge (note the absence of feeder streams) and lie on the bench formed by the Flume member which forms the base of the Cairn Formation.

The Grassi Lakes are named for Lorenzo (Lawrence) Grassi , a miner, mountaineer and park warden who lived and worked in Canmore from the 1930's until his death in 1985. Look out for the Indian pictograph on a large dolomite boulder in the middle of the valley about halfway down.

On this hike you will see a fine exposure of the Upper Devonian reef carbonates: the Southesk and Cairn Formations of the Fairholme Group. These rocks are age-equivalent to the prolific oil and gas-bearing Nisku and Leduc Formations under the Alberta Plains (see correlation chart, Fig. 5.2). The regional distribution of Woodbend Group reefs (Leduc and Grosmont Formations) and platforms (Cooking Lake Formation) in Alberta is illustrated in Figure 5.3.

Upper Devonian rocks extend across the Alberta Basin to subcrop below the Mannville Group in the Athabasca area. The Rimbey-Meadowbrook reef trend was at one time considered to be a conduit that delivered oil to the Athabasca deposit (Gussow, 1954). Recent work however (see Fowler in this field guide) indicates that the oil in Upper Devonian reservoirs is geochemically distinct from the Athabasca bitumen, indicating that the Upper Devonian was not a carrier bed for the Athabasca oil sands.

Figure 5.4 a is a detailed geological log of this section and Figure 5.4 b describing the White Man Gap geology is an extract from the CSPG Stratigraphic Sections Guidebook.

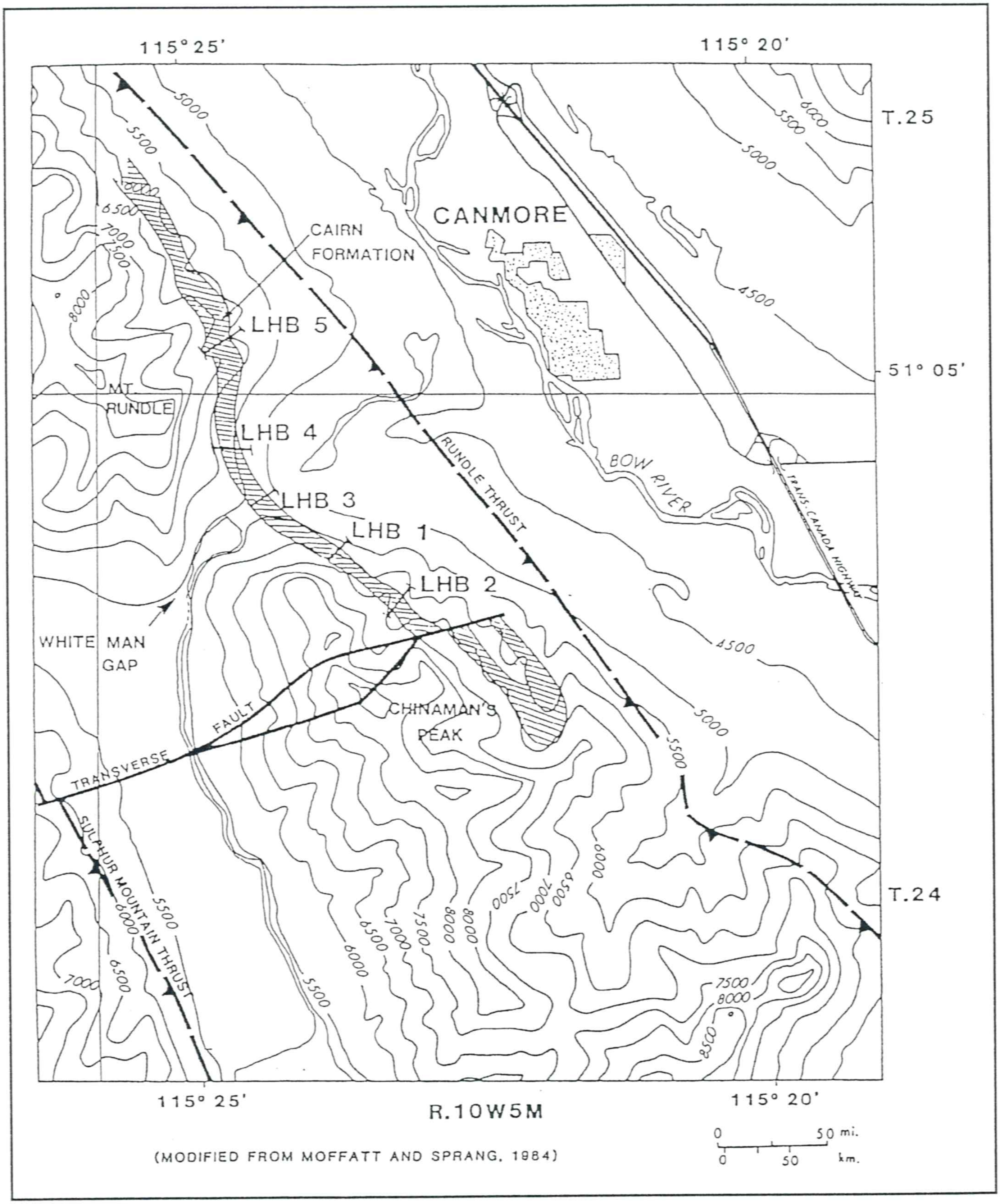

Figure 5.1 Location map and Cairn Formation outcrop, Canmore Alberta.

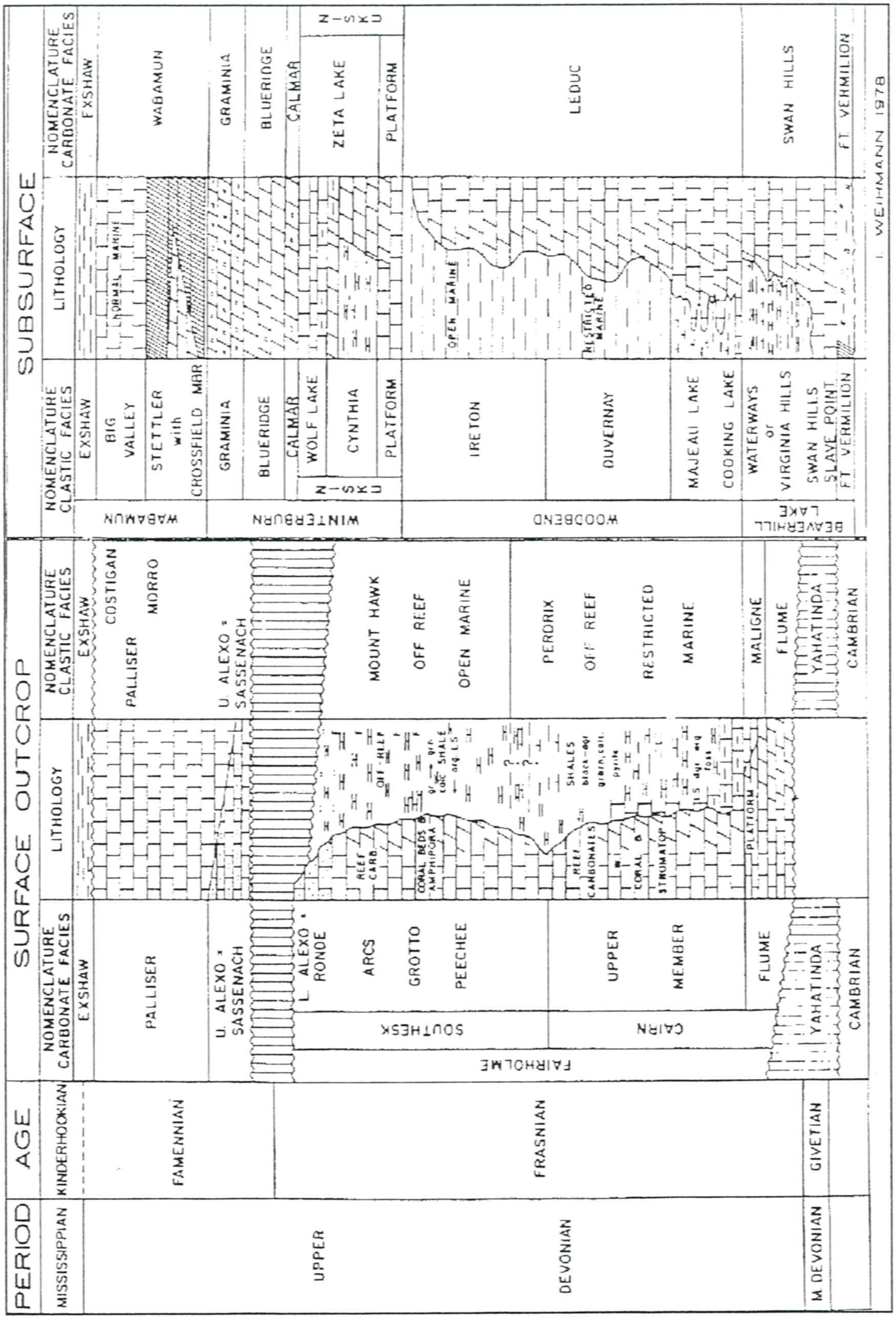

Figure 5.2 Upper Devonian correlation chart, west central Alberta.

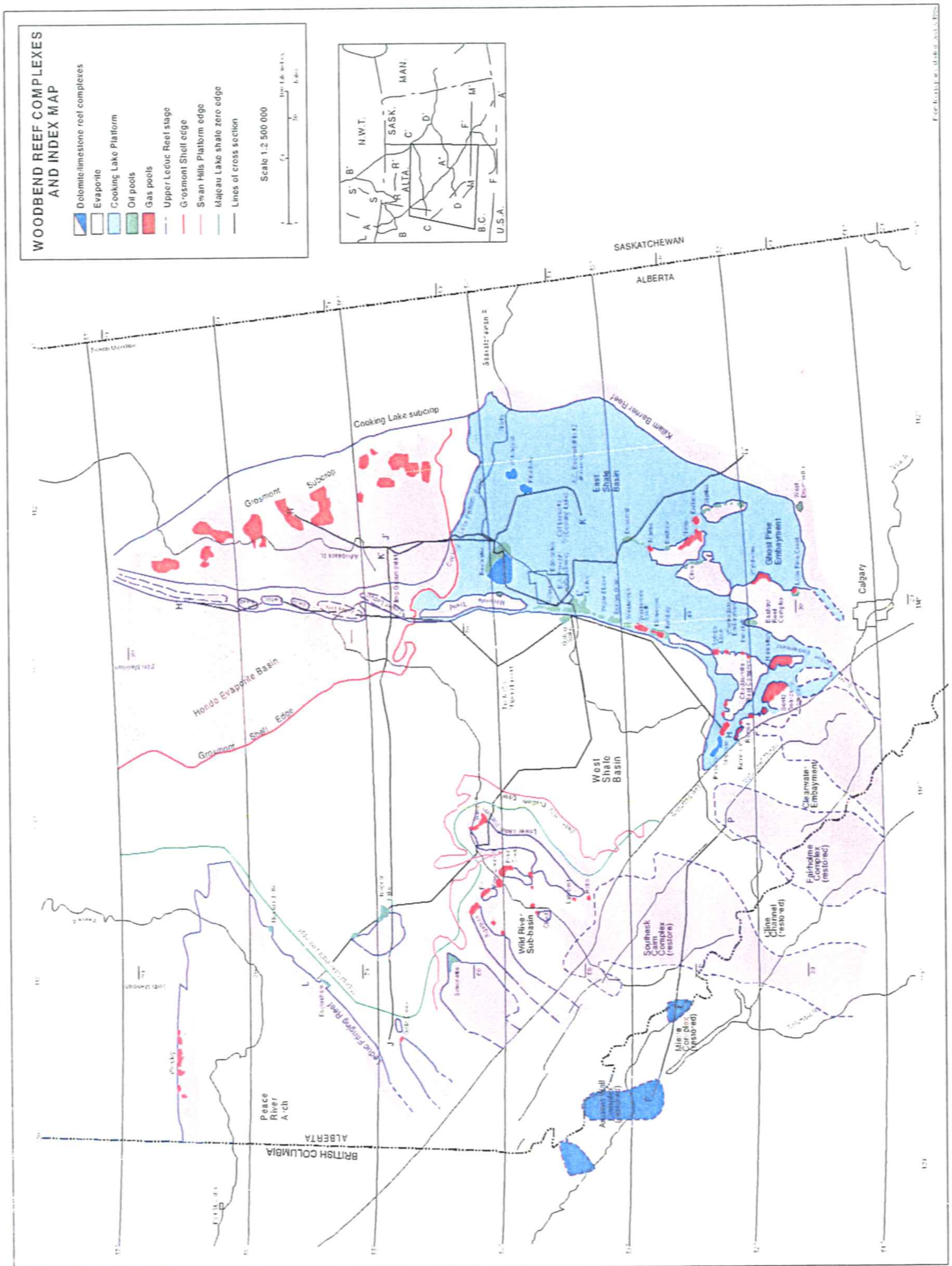

Figure 5.3 Woodbend reef complexes in the Alberta Basin.

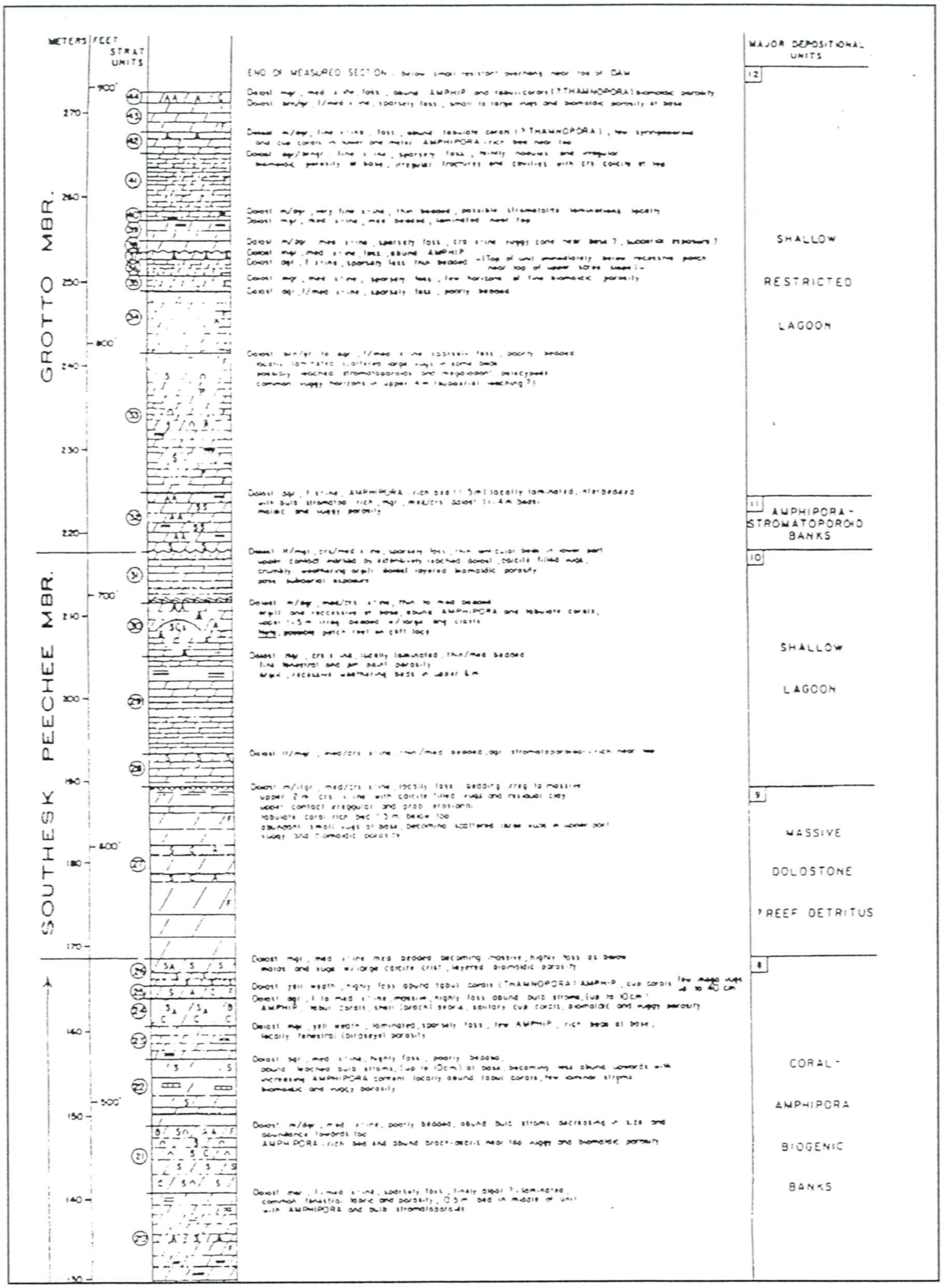

Figure 5.4a Grassi Lakes – White Man gap section log (upper Devonian Cairn and Southesk Formation).

WHITE MAN GAP

CAMBRIAN — UPPER DEVONIAN

GEOLOGICAL SECTION

CAMBRIAN

MIDDLE DEVONIAN

UPPER DEVONIAN

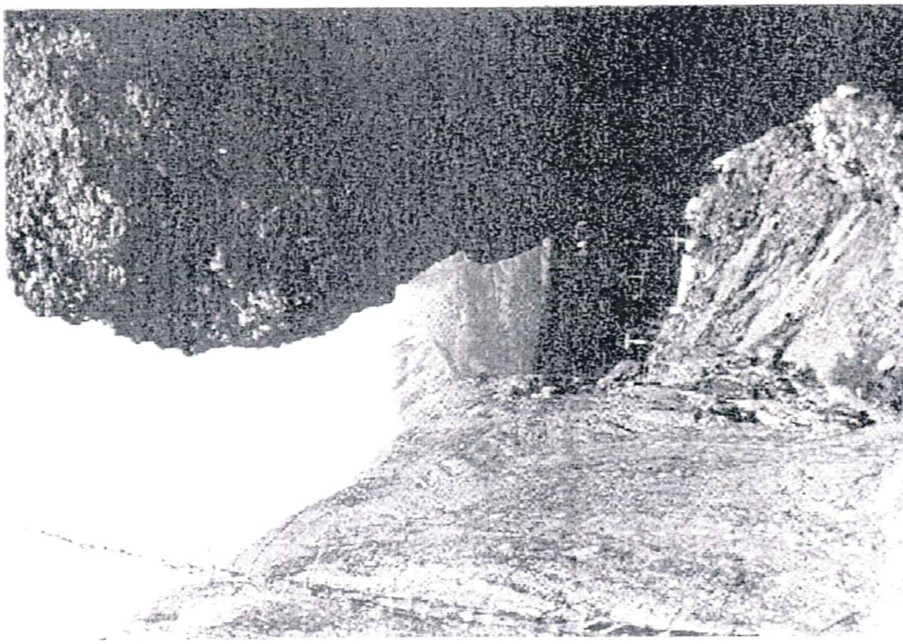

Fig. 1. Fairholme Group (Cairn Fm) reef near Spray Lakes Road (Canmore) White Man Gap.

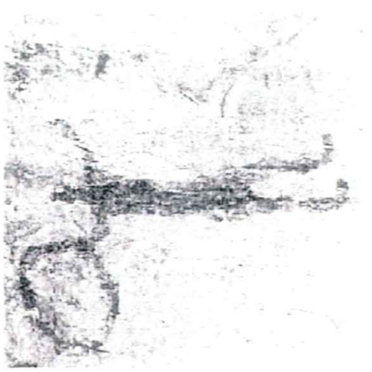

Fig. 2. Indian painting near Spray Lakes Road (White Man Gap)

MISSISSIPPIAN

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Figure 5.4b Summary field guide to geology of White Map Gap, Canmore Alberta.

Arcs Member of the Upper Southesk Formation
(Nisku Formation equivalent)

The outcrop is readily accessible along the west side of the Spray Lakes Road. A thick (2-7 m) bed of Devonian mollusc fossils is well exposed. Eliuk (1996) has described this section.

In some beds poorly preserved tabular structures may be stromatoporoids or alveolitid corals. The original limestone has been dolomitised and the mollusc fossils are generally poorly preserved molds. The paleoenvironment has been interpreted as the interior of a large carbonate bank.

Porosity and Permeability of the Arcs Member/Nisku Formation:

Core plug analysis of a hand sample obtained from this outcrop indicates a permeability of 0.5 md and a porosity of 6%. Analysis of 20 Nisku Formation core plugs from the Westrose field in central Alberta yielded the following data:

Westrose Field (T45 R28 W4)

Nisku Fm.	Porosity (arithmetic average):	5.1%
	kmax (arithmetic average):	238 md
	kmax (harmonic average):	16 md
	kmax (geometric average):	51 md

Cairn Formation (Lower Leduc equivalent)

The Cairn Formation at Grassi Lakes was deposited under shallow water shoreward of the main carbonate complex. The massive units consist of stromatoporoid bioherms and biostromes containing an abundant but restricted fauna (bulbous and dendroid stromatoporoids, tabular corals, brachiopods and gastropods). The laminated beds are Amphipora wackestones with abundant Thamnoporoid corals. Matrix and skeletal components are completely replaced by dark grey, fine grained dolomite. Many of the large bulbous stromatoporoids have been selectively dissolved, whereas smaller constituents have not.

McNamara et al (1991) studied this outcrop and the subsurface equivalent rocks at Westrose Field (Tp 45-46, R 28W4-1W5) in order to determine the effect of mega-pores on our ability to accurately estimate reservoir porosity from core data. It was assumed that if a core (10 cm diameter) intersected a mega-pore with a diameter of 9 cm or more, then the core would be considered to be "missing". They concluded that the Cairn outcrop at Grassi Lakes has an average porosity of 16.9% with 12.5% being contained in the vugs and 4.4% in the matrix. If this outcrop were actually a subsurface reservoir, which had been cored, the estimated porosity would be at least 3% too low due to mega pores being misinterpreted as missing core.

Porosity and Permeability of the Cairn Formation/Leduc:

Core plug analysis of a hand sample obtained from this outcrop yielded a permeability of 0.56 md and a porosity of 4.7%. The Nevis D-3 E pool (Tp 38 R 22 W4) produces oil from Cairn Formation equivalent rocks.

Nevis D-3 E pool (Tp 38 R 22 W4)
Core analyses 36 samples

Leduc Fm.	Porosity (arithmetic average):	11.5%
	kmax (arithmetic average):	6563 md
	kmax (harmonic average):	200 md
	kmax (geometric average):	1371 md

Rock Properties

Porosity

Porosity is the volume of the void spaces in a rock expressed as a percentage of the total rock volume. The total porosity of most reservoirs lies in the range from about 5-30%, so varies by a factor of about 6. The effective porosity is generally smaller than the total porosity (Table 5.2). The size and shape of both the pore bodies and the pore throats controls the ease with which oil at a given saturation can move in water wet carrier beds. The porosity "architecture" therefore impacts both the pooling of petroleum and its production. Various descriptive terms are used to characterize different porosity types e.g., intercrystalline, vuggy, interparticle, fracture etc. and reservoir rocks often have multiple porosity types. Figure 5.5 shows some relationships between texture and porosity. The largest vugs that you will observe in the Cairn Formation at Grassi Lakes have been enlarged by near-surface weathering (Mossop, 1994). Intercrystalline porosity of the dolomite matrix typically forms the major reservoir space in upper Devonian reservoirs in the Alberta subsurface with minor vuggy porosity. Fracture porosity is locally important.

Questions:

Which of these rocks do you think would make the better petroleum reservoir: a rhyolite pumice with 70% porosity or an intensely fractured shale with porosity of 15%? What then is the key feature of porosity that creates a good reservoir?

TABLE 5.1 - Regional scale porosity and permeability data for formations in northeast Alberta

a) Regional Scale Permeability Measurements from Drill-Stem Tests and Core Analyses, Northeast Alberta

Hydrostratigraphic Unit	From Drill-Stem Tests: No. of Wells	Minimum	Maximum	Geometric Average	σ_y**	Maximum Permeability (k_m) from Cores: No. of Wells	Minimum	Maximum	Geometric Average	σ_y**
Viking	51	0.046	5207	1.86	2.4808	12	26.30	5960	697.86	1.78
Grand Rapids	416	0.027	6712	41.73	2.4675	101	0.04	6270	488.12	2.09
Wabiskaw	200	0.012	5464	8.41	2.4525	269	0.10	6900	254.50	1.92
McMurray	365	0.023	8085	13.66	2.5918	382	0.01	9980	262.81	2.97
Wabamun	24	0.124	1465	24.33	2.8952	24	1.52	2460	32.31	2.01
Winterburn	34	0.135	1900	9.81	2.5110	39	0.06	1370	14.53	2.17
Grosmont	55	0.028	1591	10.75	2.2530	6	0.25	96	6.50	2.36
Cooking Lake	7	0.003	1556	1.80	4.6362	34	0.01	10200	39.67	5.31
Beaverhill Lake	22	0.036	1122	91.16	2.1980	9	0.01	9	0.20	2.79
Contact Rapids-Winnipegosis	31	0.001	273	1.03	3.1296	49	0.01	175	0.43	2.21

*Permeability measurements are in millidarcys; 1 darcy = 0.987×10^{-12} m².
**σ_Y is the variance of Y = ln(k).

b) Regional Scale Porosity from Core Analyses, Northeast Alberta

Hydrostratigraphic Unit	No. of Wells	Minimum	Maximum	Arithmetic Average	σ_ϕ*
Viking	16	0.27	0.38	0.33	0.04
Grand Rapids	285	0.09	0.42	0.35	0.03
Wabiskaw	1558	0.06	0.42	0.31	0.02
McMurray	4822	0.02	0.43	0.32	0.01
Wabamun	30	0.03	0.34	0.17	0.06
Winterburn	56	0.04	0.33	0.20	0.06
Grosmont	193	0.02	0.36	0.15	0.04
Cooking Lake	19	0.01	0.36	0.26	0.08
Beaverhill Lake	1057	0.003	0.42	0.31	0.02
Contact Rapids-Winnipegosis	52	0.01	0.38	0.08	0.07

*σ_ϕ is the variance of the porosity distribution.

From Bachu and Underschultz, 1993

Table 5.2 Range in values of porosity

a) Range in Values of Porosity

Material	Porosity (%)
SEDIMENTARY	
Gravel, coarse	24–36
Gravel, fine	25–38
Sand, coarse	31–46
Sand, fine	26–53
Silt	34–61
Clay	34–60
SEDIMENTARY ROCKS	
Sandstone	5–30
Siltstone	21–41
Limestone, dolomite	0–20
Karst limestone	5–50
Shale	0–10
CRYSTALLINE ROCKS	
Fractured crystalline rocks	0–10
Dense crystalline rocks	0–5
Basalt	3–35
Weathered granite	34–57
Weathered gabbro	42–45

b) Range in Values of Total and Effective Porosity

	Total porosity (%)	Effective porosity (%)
Anhydrite[1]	0.5–5	0.05–0.5
Chalk[1]	5–20	0.05–0.5
Limestone, dolomite[1]	5–15	0.1–5
Sandstone[1]	5–15	0.5–10
Shale[1]	1–10	0.5–5
Salt[1]	0.5	0.1
Granite[2]	0.1	0.0005
Fracture crystalline rock[2]	—	0.00005–0.01

[1]Data from Croff and others (1985).
[2]Data from Norton and Knapp (1977).

From Domenico and Schwartz, 1990

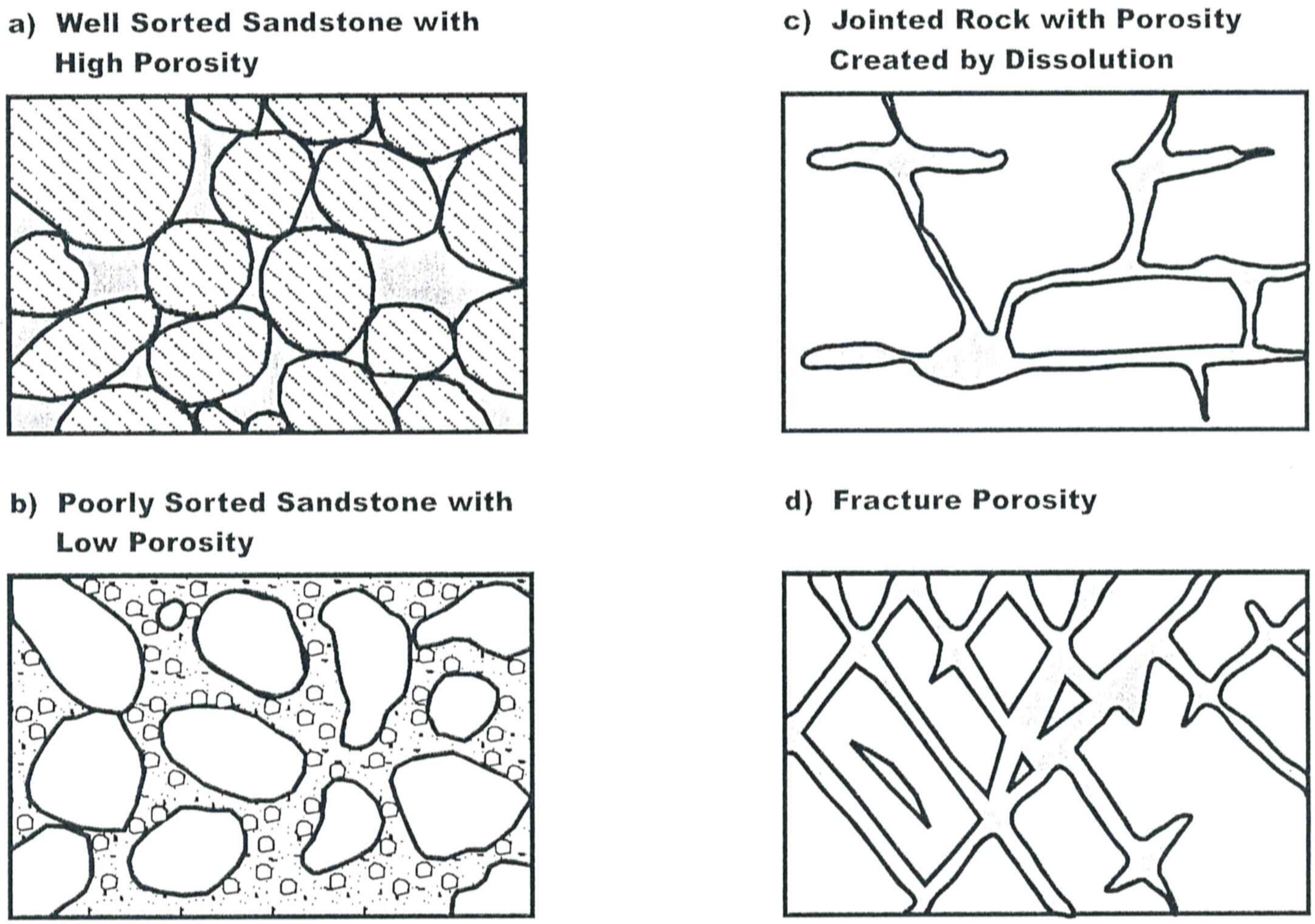


FIGURE 5.5 - Relationship between texture and porosity

Permeability

Permeability determines the ease/difficulty with which fluid moves through a rock. Permeability varies over a far greater range than porosity. The permeability of most reservoir rocks lies within the range 10 millidarcys to 100 darcys (i.e., by a factor of 10,000). Permeability is a parameter related to the porosity "architecture". The key feature of "effective" porosity is the manner in which the pores in the rock are inter-connected. The permeability of a rock to any fluid at 100% saturation is termed "intrinsic permeability", and in most formations the intrinsic permeability has different values when measured in different directions. This quality is termed **anisotropy**. Most sedimentary rocks have a maximum permeability parallel to bedding (horizontal perm.), the minimum being perpendicular to bedding (vertical perm.). This is because elongate and platy mineral grains are usually deposited flat. Porosity and permeability are usually positively correlated. When multiple fluid phases are present (e.g., oil and water), capillary forces come into play and the permeability of the reservoir rock to each fluid must be specified individually. Each fluid is characterised by a "relative" permeability, which varies between zero and 100% of the intrinsic permeability depending on the saturation levels. Figure 5.6, shows a relative permeability plot for oil and water together with a capillary pressure curve for the reservoir.

Questions:

What would you expect the permeability to gas to be in a sandstone reservoir where the fluid mix is 80% oil, 15% water and 5% gas?

If a reservoir contains 85% water and 15% oil, and the oil is at "residual saturation", what is the relative permeability of the reservoir to oil?

Diagenesis, Porosity and Permeability

According to Machel (1999) the realm of diagenesis comprises all mineralogical, physical and chemical changes of sedimentary deposits between the time of ultimate deposition and the onset of metamorphism (greenschist facies). A variety of diagenetic processes act on rocks in the subsurface, which modify the rock's flow characteristics. Figure 5.7 lists six processes that destroy, and eight processes that enhance porosity and permeability. This figure indicates that the opportunity for groundwater circulation greatly diminishes with depth below about 100 m. However, there is ample evidence in the Athabasca region of groundwater penetration to a depth of at least 1,000 m. Machel (1999) identifies cementation, dissolution and dolomitization as processes that require significant groundwater flow. Tóth (1999) notes that groundwater flow systems function as "conveyor belts" for the transport of mass. Recharge areas where fresh and chemically aggressive water enters the subsurface are preferred sites of mineral dissolution and groundwater loading. Discharge areas where saline waters emerge at the ground surface and experience a drop in pressure and temperature, are preferred sites of mineral precipitation.

Figure 5.8 shows the ranges of porosity, pore size and hydraulic conductivity (in m/day) for various carbonate rock types. Note the impact of fracturing, which can increase the permeability of a given rock type up to 100,000 fold (five orders of magnitude).

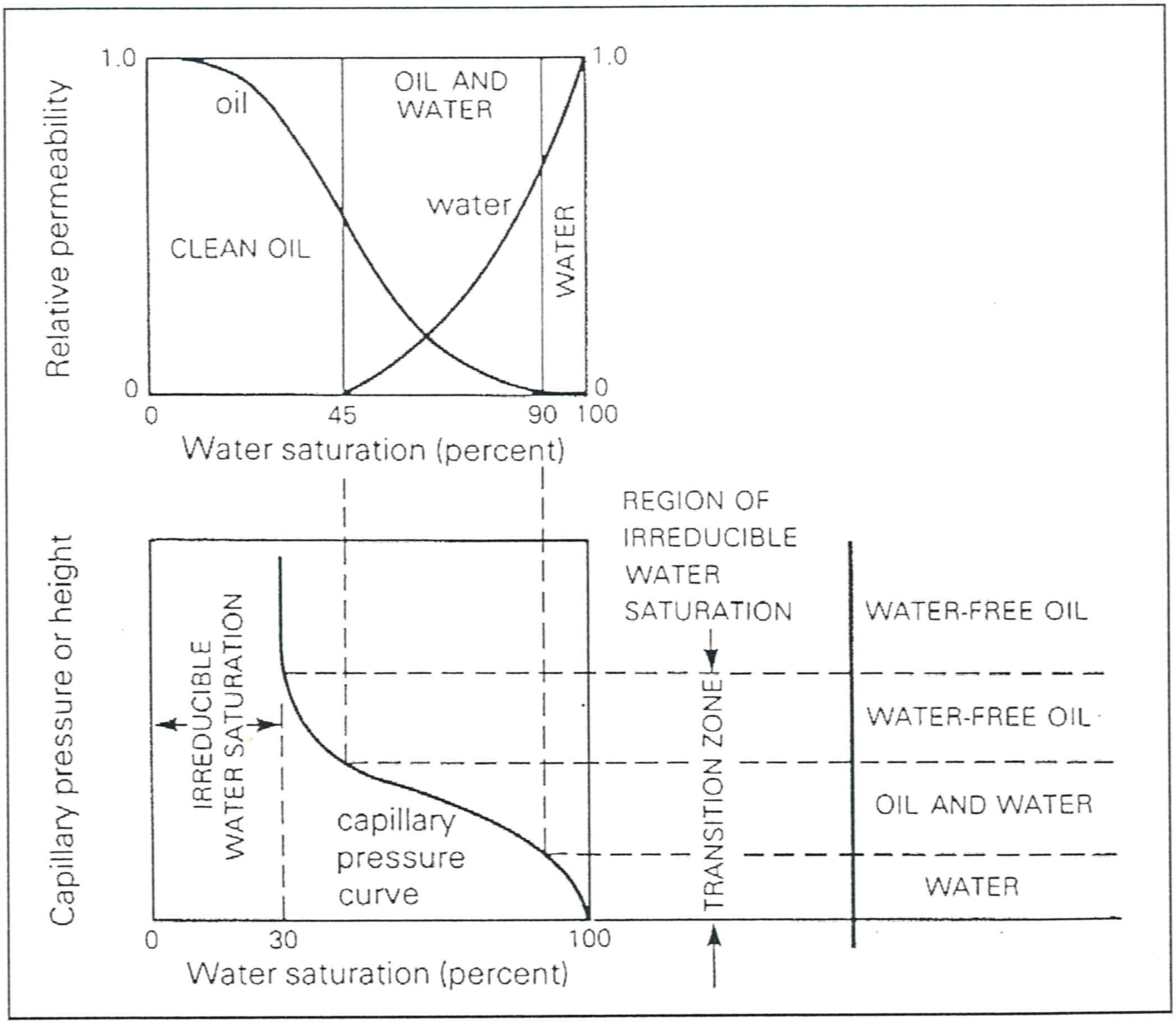
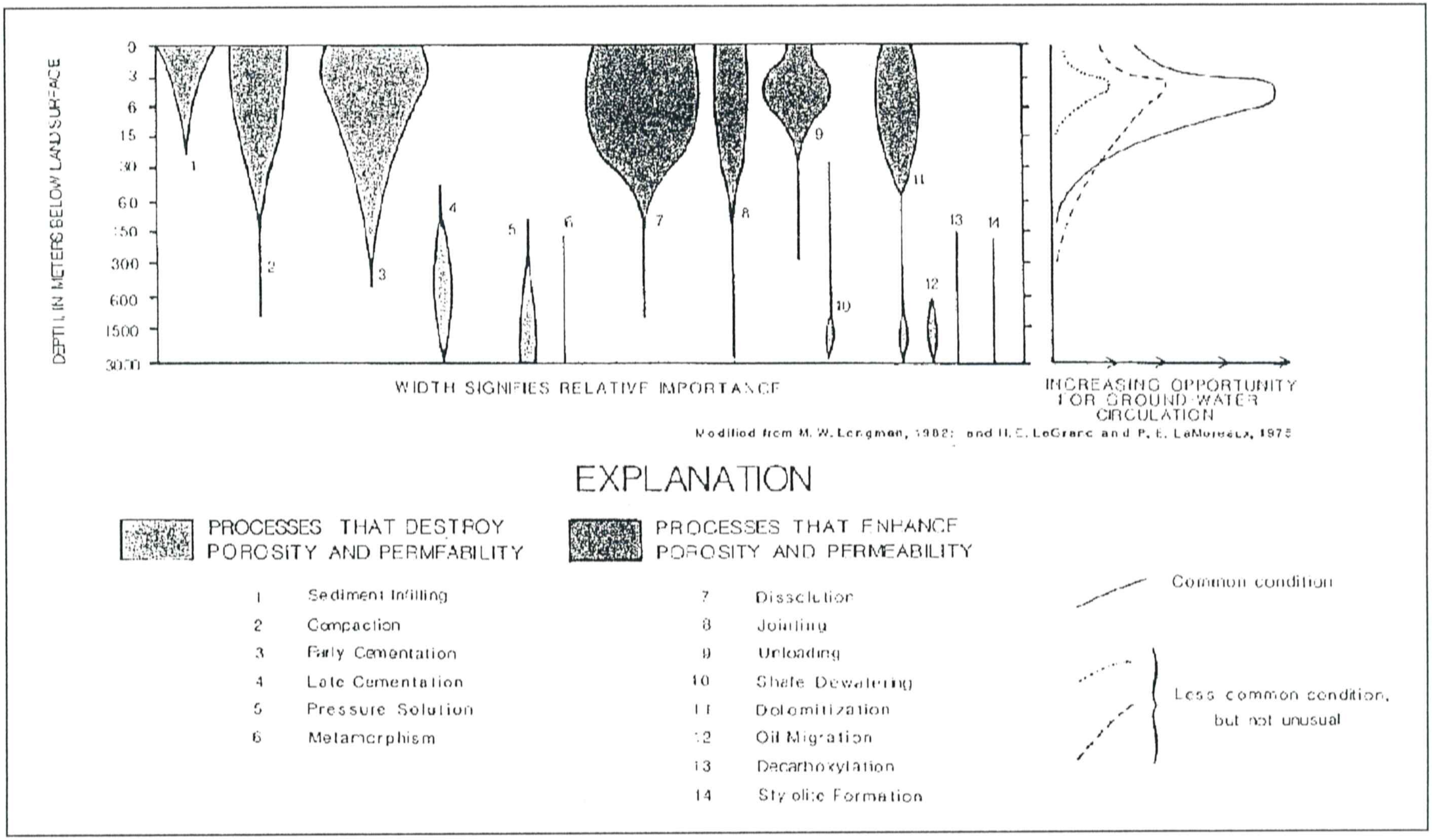
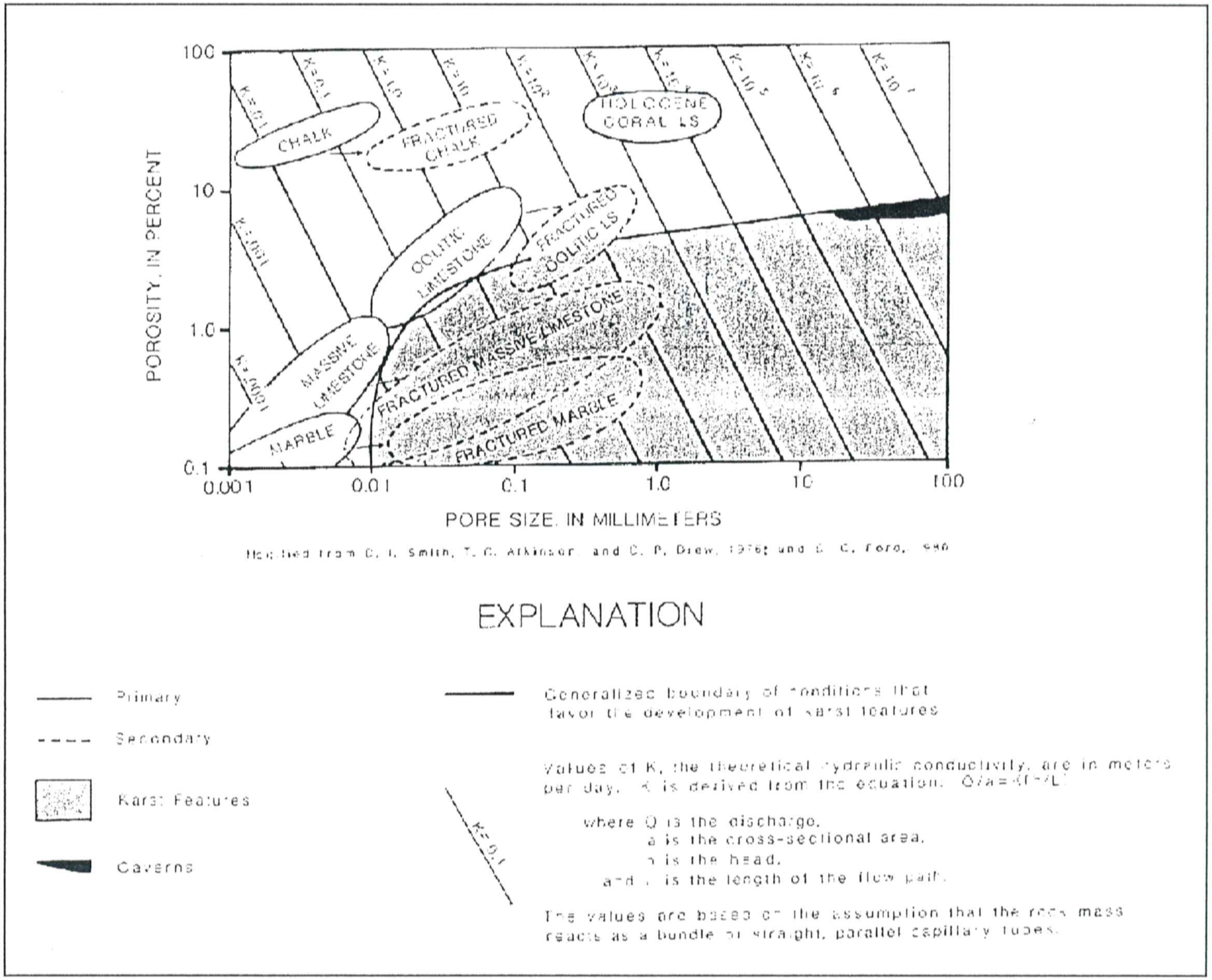


Figure 5.6 - Relative permeability and capillary pressure curves



From Brahana et al., 1988

Figure 5.7 Relation between depth, groundwater circulation and selected processes that destroy and enhance porosity and permeability in carbonate rocks



From Brahana et al., 1988

Figure 5.8 Primary and secondary porosity, pore size and theoretical hydraulic conductivity of selected carbonate rocks, karst features and caverns

Introduction to the Calculation of Fluid Flow
White Man Gap Dam

The 30 m high White Man Gap Hydro Plant is operated by Transalta Utilities. The earthen dam was completely reconstructed between July and November 1995. During the reconstruction, the water level in the reservoir was lowered 10 feet and the flow was fed at a reduced rate into the Hydro Plant below Grassi Lakes. During the reconstruction period, the plant produced 2 x 10 megawatts, it now generates 2 x 50 megawatts.

The reconstructed earth fill dam has a low permeability core (made of glacial till) with high permeability sand filters around the core. This arrangement produces a far more stable structure than a homogeneous fill, and is designed to prevent "sloughing" of the interior face of the dam in the event of a rapid drop of the water level in the reservoir. Figure 5.9 shows two dam profiles: Figure 5.9a has a homogeneous fill and Figure 5.9b has a permeable shell design. The head distributions that follow rapid reservoir water level drop show a large (unstable) pressure gradient across the inner face for the homogeneous dam versus no appreciable pressure gradient for the permeable shell design.

Questions:

As of January 2000, the peizometres at the toe of the dam were dry. What does this indicate about the permeability of the dam?

Do you expect that the toe piezometres will eventually intercept water?

Estimate the Dam Permeability

We will re-visit Darcy's Law at Stop 8 where we use it to calculate oil migration rates across the Alberta Basin. At the present stop we introduce Darcy's Law by using it to estimate the permeability of the White Man Gap Dam. The reconstructed White Man Gap earth dam is now about 4 years old and the toe piezometres are still dry. If water is passing through the dam (which is about 30 m wide at the base) we can estimate the maximum permeability assuming that the water front emanating from the reservoir is "just about to arrive" at the toe.

The hydraulic gradient is: *30 m (head drop) / 30 m (horizontal travel path) = 1.0*

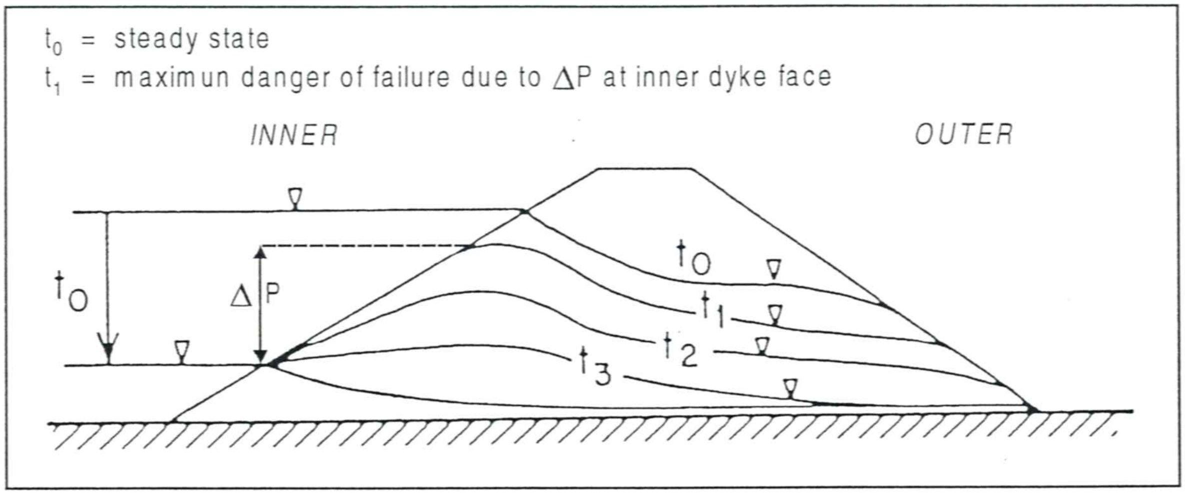
The average flow velocity is: *30 m / 4 years = 30 / 126,144,000 sec = 2.38 E-07 m/sec*

We can estimate the maximum bulk permeability of the dam fill using Darcy's Law:

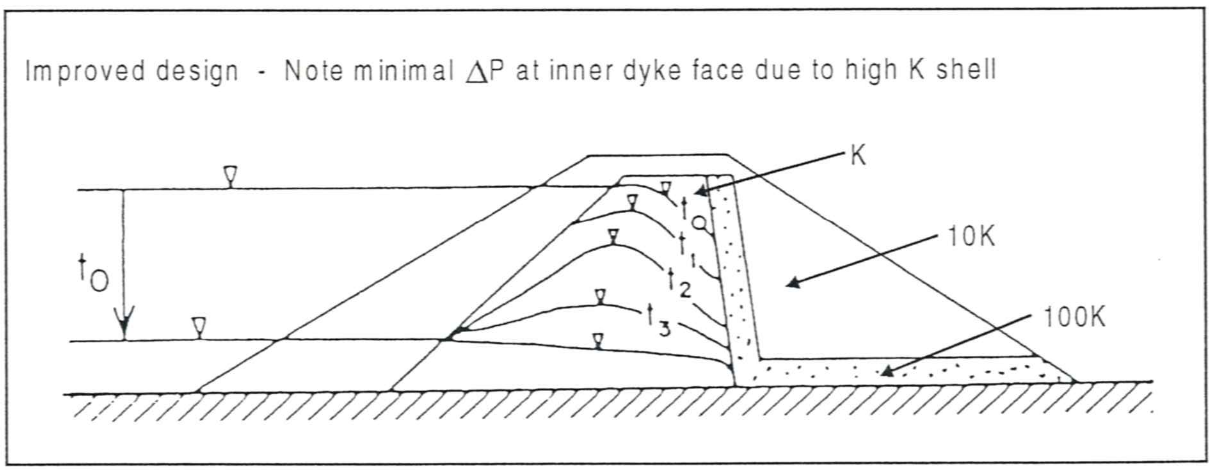
$$v = (K * grad\ h) / n$$

Where v is the average linear water flow velocity in m/sec, K is the hydraulic conductivity in m/sec (proportional to permeability), *grad h* is the head gradient and n is the porosity of the dam fill (estimated to be 10%).

a) Homogeneous Dam



b) Zoned Dam with Permeable Shell



By Freeze and Cherry, 1979

Figure 5.9 Transient response of water table in an earth dam to rapid drawdown of the reservoir

Rearranging terms to solve for the hydraulic conductivity:

$$K = (v * n) / grad\ h$$

Since the head gradient is 1.0, and the porosity is 0.1, the maximum hydraulic conductivity is 2.38 E-08 m/sec,

2.38 E-08 m/sec = *(*2.38 E-07 m/sec * *0.1) / 1*

which is equivalent to about 2.5 md (Table 5.3). This is the maximum possible bulk permeability of the dam.

Note that this exercise is somewhat over-simplified because this example represents a case of transient rather than steady state flow. Hence a slightly more complicated flow equation than that given above should actually be used.

Questions:

If the water front emanating from the reservoir did not arrive until 2010 (15 years after construction) what would be the maximum possible calculated bulk permeability of the dam?

Answer: about 0.7 md.

Note that the dam engineers estimate that water breakthrough will occur after 15 years.

Finally look at Figure 5.10 which shows two generic dam profiles. What is the difference between Figure 5.10 a and Figure 5.10 b, and which do you think is more representative of the situation at the White Man Gap Dam?

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Acknowledgements

Thanks are due to Jim Underschultz, Steve Burnie and Eric Dahlberg, co-leaders of the 1997-98 CSPG Field Trip "Holes in the Rockies" when we first visited Grassi Lakes. Brian Pelz of TRANSALTA UTILITIES is thanked for kindly providing information about the White Man Gap dam.

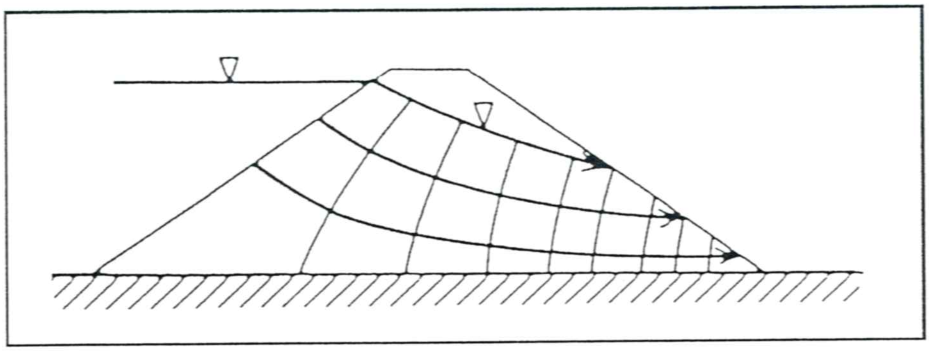
Table 5.3 Representative hydraulic conductivities for various rock types

Material	Hydraulic conductivity (m/sec)
SEDIMENTARY	
Gravel	3×10^{-4} – 3×10^{-2}
Coarse sand	9×10^{-7} – 6×10^{-3}
Medium sand	9×10^{-7} – 5×10^{-4}
Fine sand	2×10^{-7} – 2×10^{-4}
Silt, loess	1×10^{-9} – 2×10^{-5}
Till	1×10^{-12}–2×10^{-6}
Clay	1×10^{-11}–4.7×10^{-9}
Unweathered marine clay	8×10^{-13}–2×10^{-9}
SEDIMENTARY ROCKS	
Karst and reef limestone	1×10^{-6} – 2×10^{-2}
Limestone, dolomite	1×10^{-9} – 6×10^{-6}
Sandstone	3×10^{-10}–6×10^{-6}
Siltstone	1×10^{-11}–1.4×10^{-8}
Salt	1×10^{-12}–1×10^{-10}
Anhydrite	4×10^{-13}–2×10^{-8}
Shale	1×10^{-13}–2×10^{-9}
CRYSTALLINE ROCKS	
Permeable basalt	4×10^{-7}–2×10^{-2}
Fractured igneous and metamorphic rock	8×10^{-9}–3×10^{-4}
Weathered granite	3.3×10^{-6}–5.2×10^{-5}
Weathered gabbro	5.5×10^{-7}–3.8×10^{-6}
Basalt	2×10^{-11}–4.2×10^{-7}
Unfractured igneous and metamorphic rocks	3×10^{-14}–2×10^{-10}

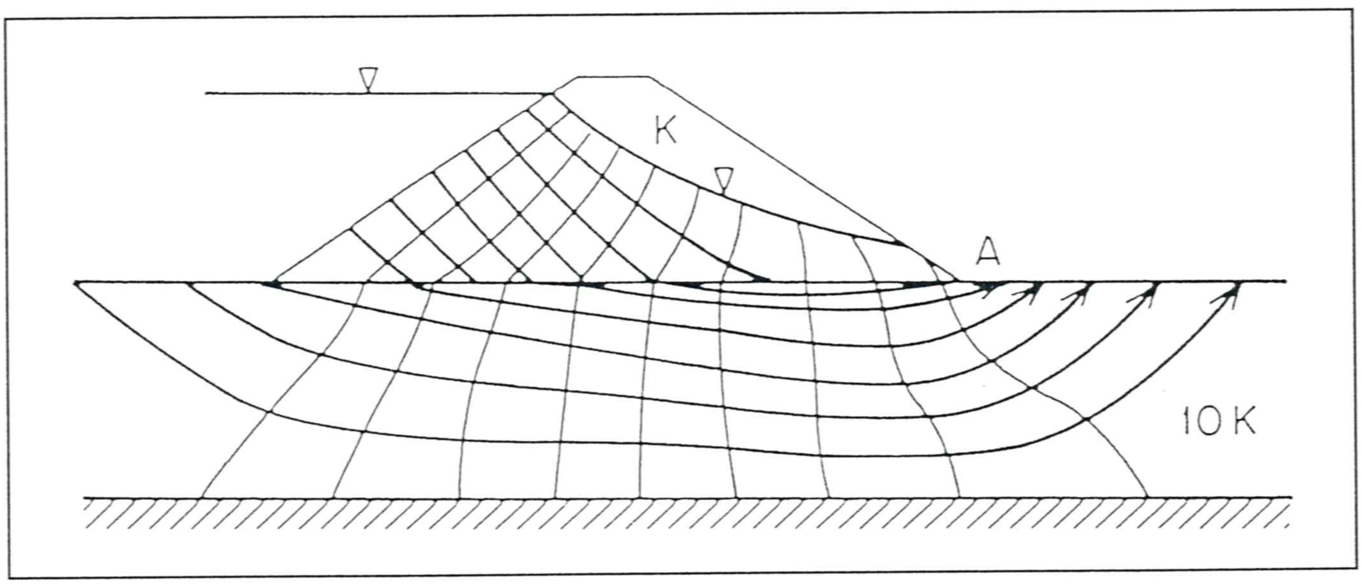
To convert meters per second to	Multiply by
cm/sec	10^{2}
(gal/day)/ft^{2}	2.12×10^{6}
ft/sec	3.28
ft/yr	1×10^{8}
darcy	1.04×10^{5}
ft^{2}	1.1×10^{-6}
cm^{2}	1×10^{-3}
To convert any of the above to meters per second	Divide by the appropriate number above

From Domenico and Schwartz, 1990

a) Impermeable Foundation



b) Permeable Foundation



From Freeze and Cherry, 1979

Figure 5.10 Flow nets for homogeneous, isotropic dam

Hydrodyanmic Controls on Foothills Gas Pools

Introduction

The foothills of Western Canada consists of a belt of mountainous terrain and rolling hills along the eastern slope of the Rocky Mountains (Fig. 6.1). The surface terrain in many respects reflects the sub-surface with rock ranging in age from Cambrian to Cretaceous. These rocks were thrusted and folded during the Larimide period some 60 million years ago. As a result many traps were formed which contain large quantities of hydrocarbons primarily gas.

Characterizing the nature of flow systems in the thrust-fold belt is important for two main reasons. From an academic viewpoint it represents a critical part of the overall basin Scale flow. It has been speculated that it could either represent a significant recharge region for many shallow and deep aquifers, or alternatively, represent a relatively closed system disconnected from deeper undisturbed aquifers.

More practically, there are large reserves of pooled hydrocarbons trapped within this strata whose distribution and pressures are impacted by formation water flow systems in the thrust fold belt.

With the growing demand for natural gas in North America, the Canadian oil industry has, and even more so now, focused on the potential of the Canadian Foothills. With the growing demand ever increasing from 25 TCf* currently to a rate of 30 TCF* by 2010 (NEWSON), this puts a huge demand to continually explore for and develop new natural gas reserves. The current replacement reserve is declining at a rate of approximately 7 percent per annum in Canada and a rate of 17persent in North America.

So the foothills belt of Western Canada, a predominantly gas prone region, provides opportunity to explore for and develop the required reserves. This region referred as the disturbed belt is controlled by over-thrust tectonics. The southern half of the foothills has approximately 40 TCF of gas in place of which 23 TCF is marketable. A total of approximately 43 TCF has been produced to date in this region over the past 50 years (Newson).

The Foothills region of the Western Canadian sedimentary basin is dominated by over-thrust tectonics (Fig.6.2). The depositional model of deformation within the foothills belt is one of laterally shortened fold/fault-dominated structures. The play types evident across our region of examination are (Figs. 6.3, 6.4):

1. First generation play types low angle thrust faults eg. Wildcat Hills, Benjamin Creek
2. Second Generation play types e.g. Waterton, Savana
3. Reefs ; Devonian Wabamun / Leduc eg; Limestone

The challenge for exploration and development lies in the necessary application to mold all of the geological and geophysical data currently available to successfully explore for and develop new reserves.

The challenge to due hydrodynamic evaluations on these complexes was enormous. The challenge to get good pressure data representing the often low permeability conditions of the matrix rock required employing not just Drill Stem test data but any of the other testing devices employed during the testing of the reservoir encountered. Data used consisted of Drill Stem tests, Wireline tests, Static gradient tests and AOF buildup data.

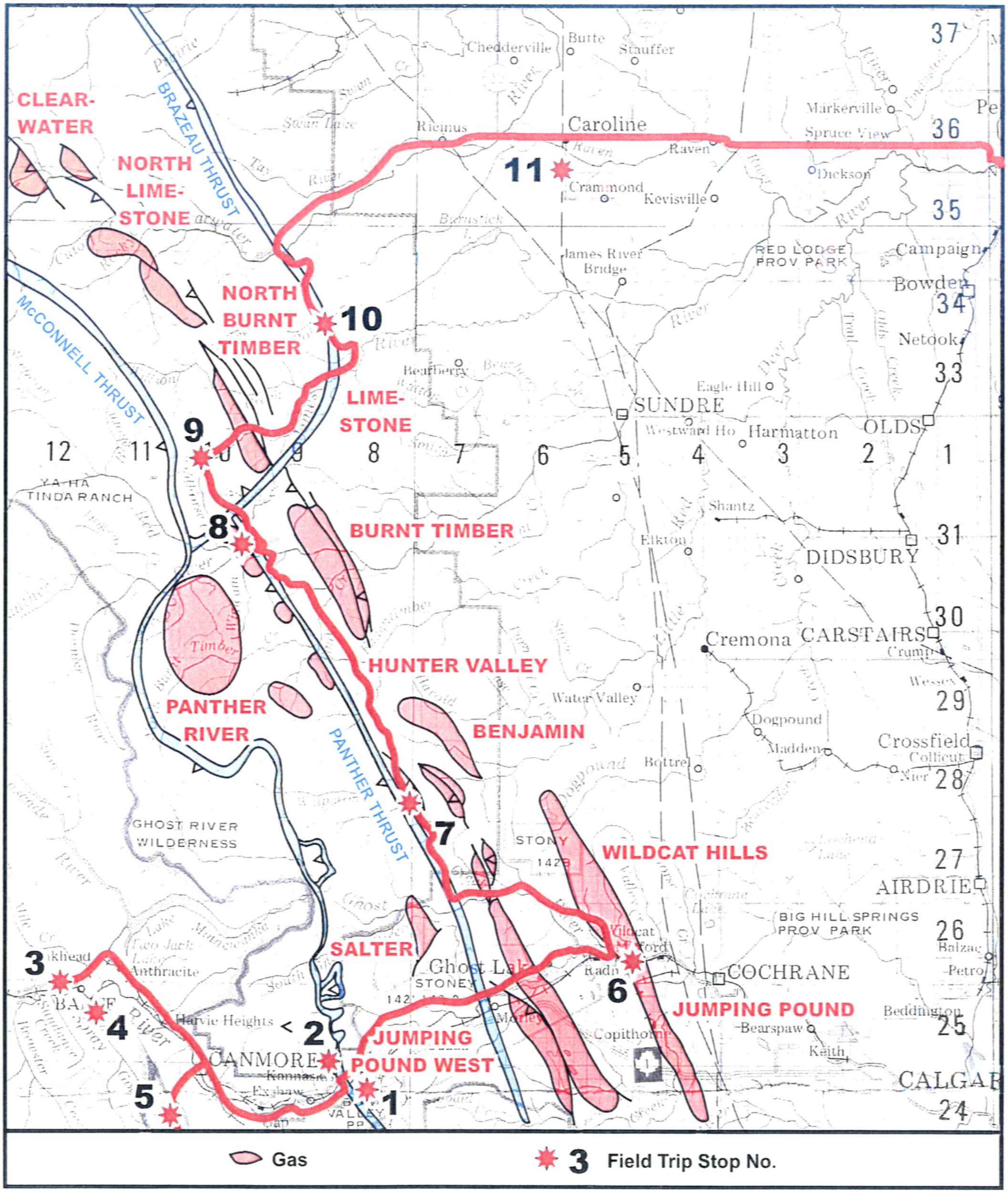


Figure 6.1 Location map for day 1 and 2 : Foothills thrust faults & Mississippian gas pools

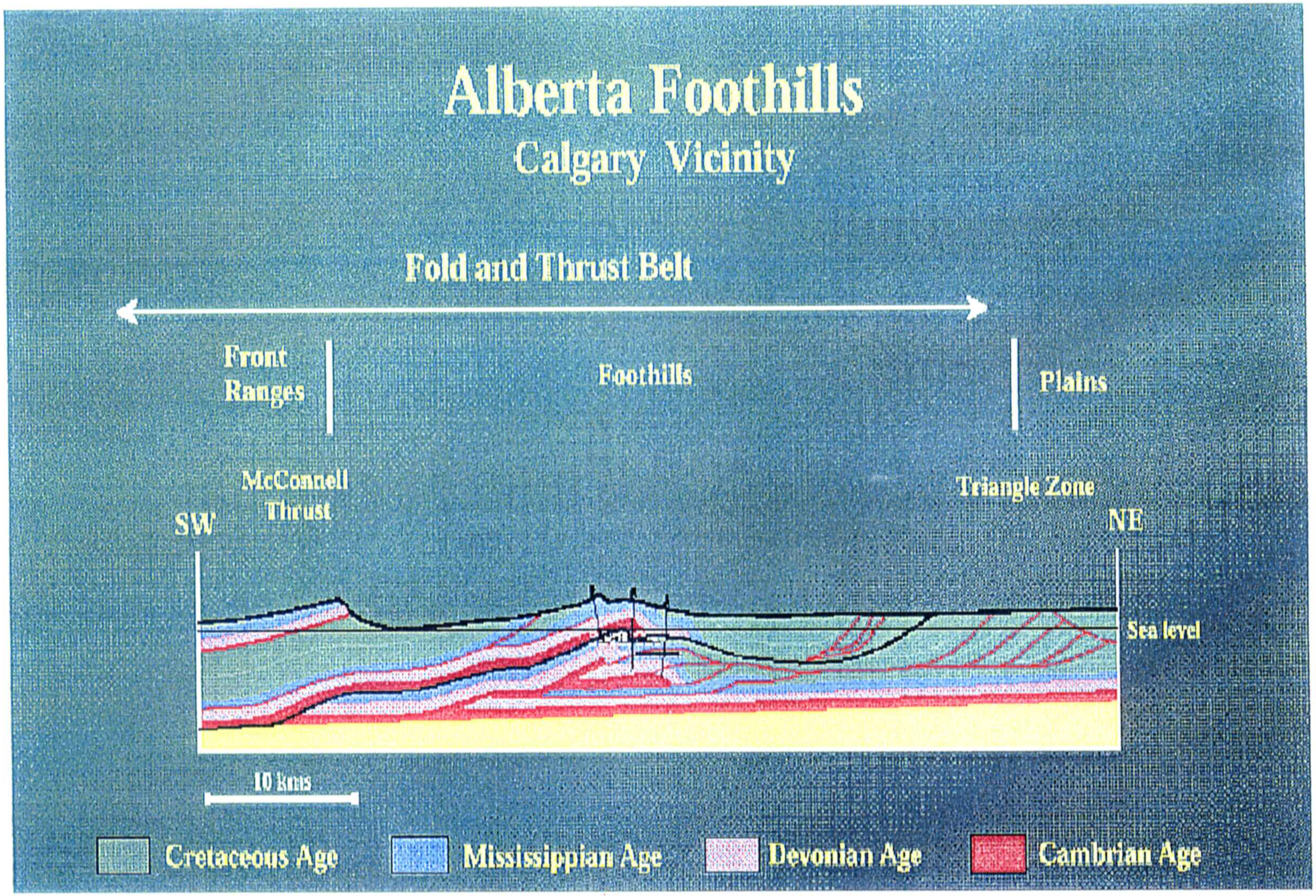


Figure 6.2 Cross section schematic of the disturbed belt.

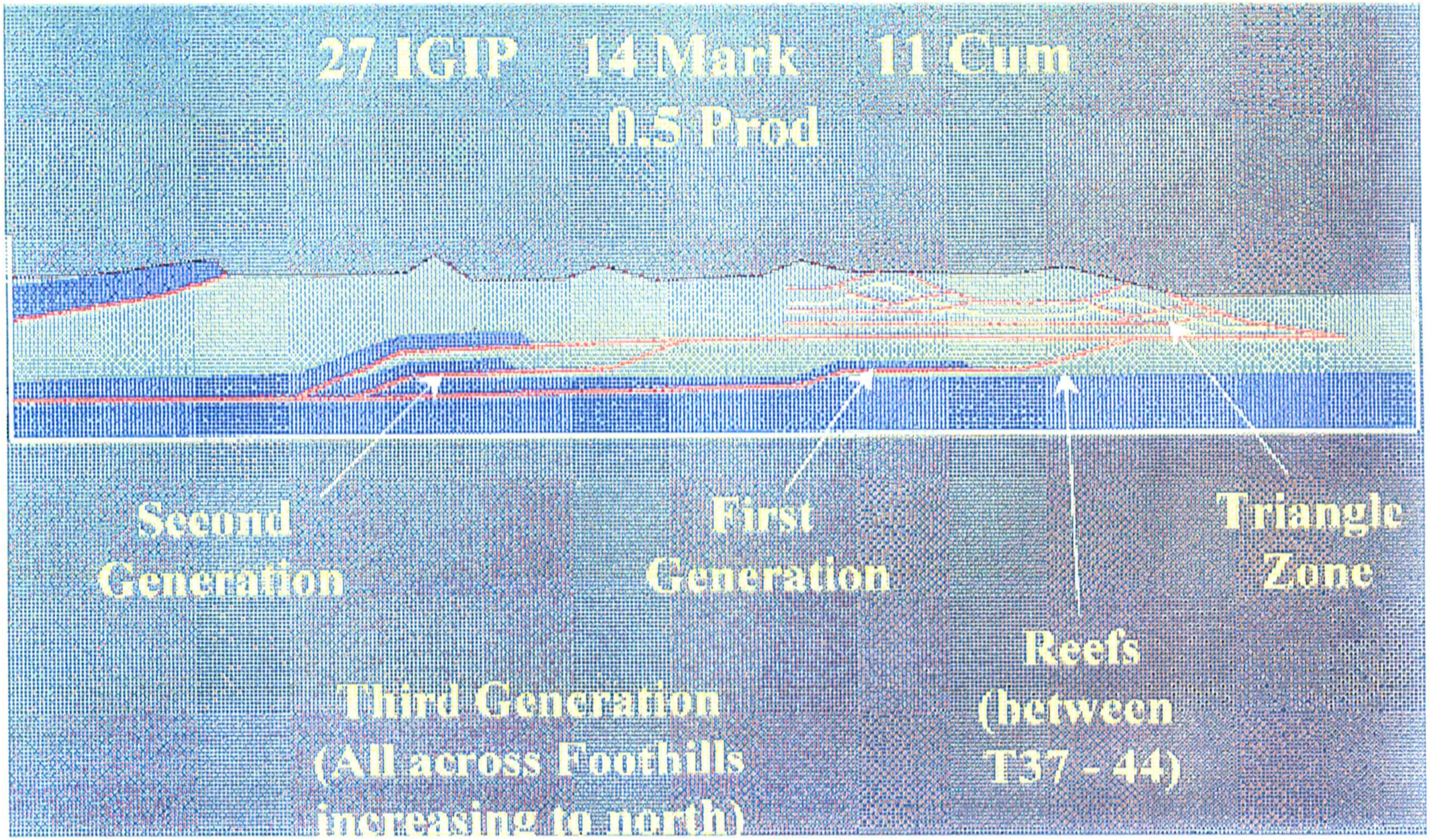


Figure 6.3 Alberta Foothills Play-types

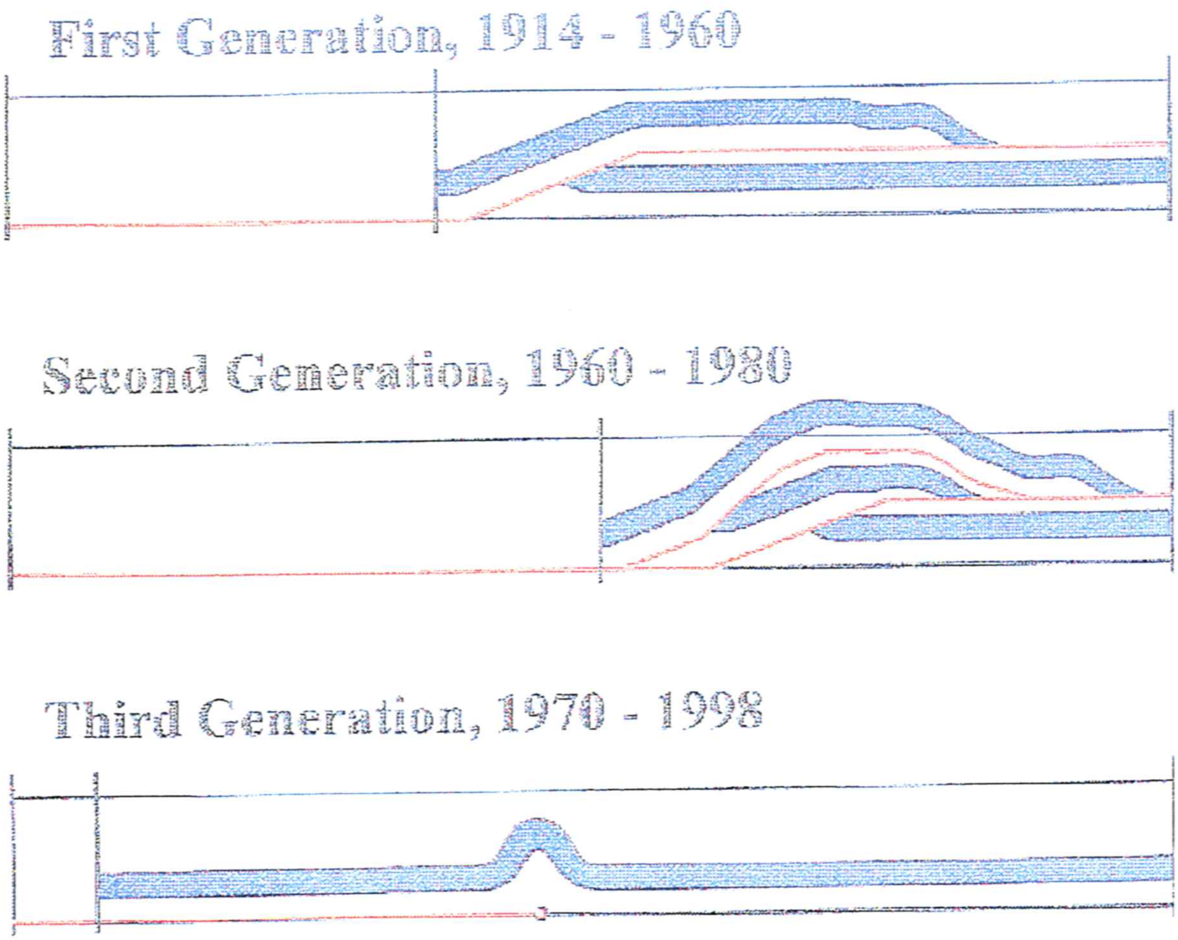


Figure 6.4 Play/Trap types typically found along the disturbed belt.

The reservoir rock usually consists of a fairly thick section but lacks permeability and consists of a low matrix porosity. So successful exploration is dependent on locating the fracture development within the reservoir rock as many times reservoir are encountered but may prove uneconomical.

During the folding process the reservoirs were fractured and provide good permeability conduits with effective matrix porosity (Fig. 6.5). So many technical elements are required to be employed in the exploration of foothills complexes to assist in the success of economic play development.

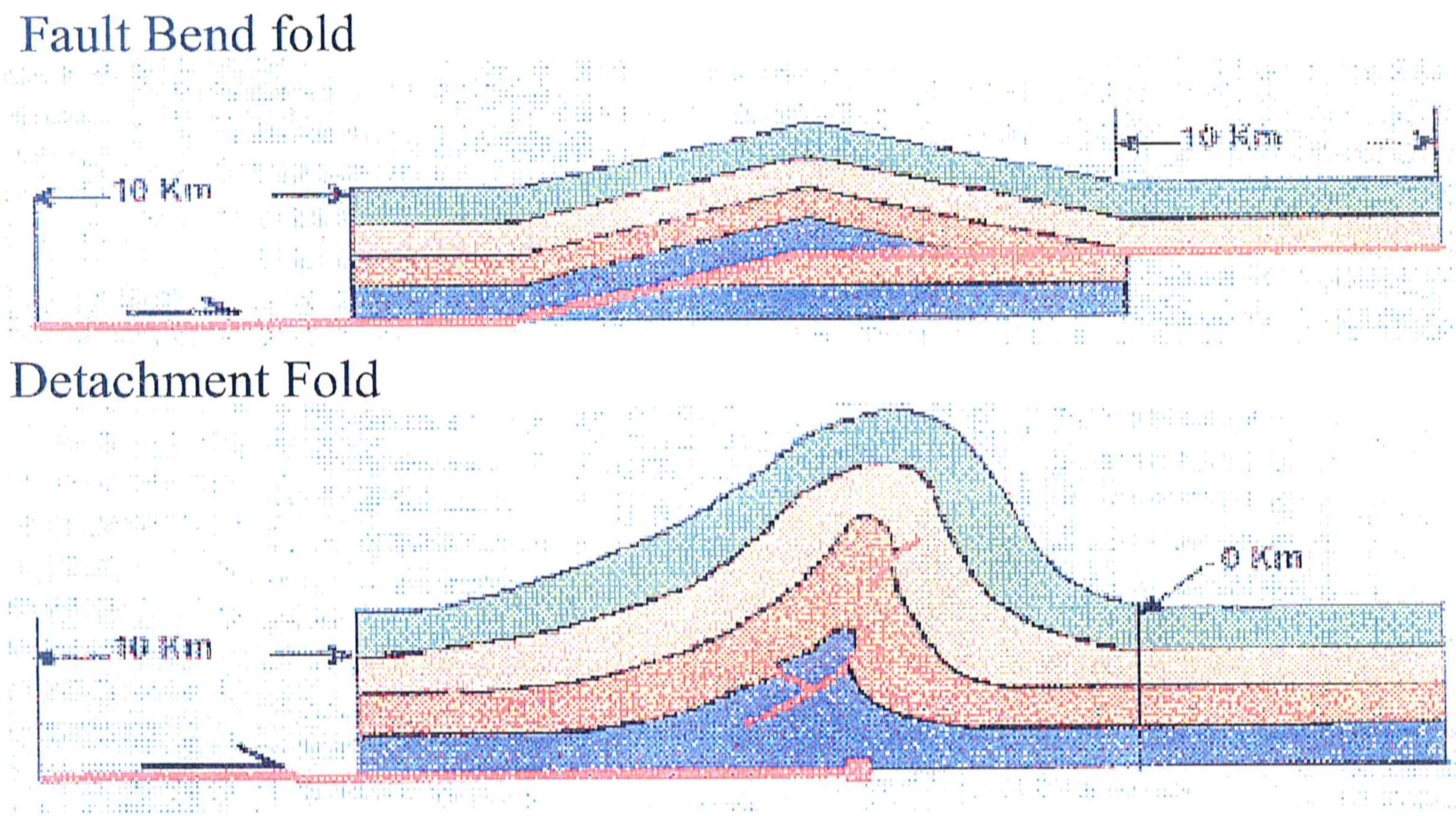


Figure 6.5 Fault types schematic.

Hydrodynamic Controls of the Foothill's Gas Pools.

There are few public domain references to hydrodynamic systems developed in thrusted and fold strata. This is principally due to the lack of public access to seismic data required for defining the complex stratigraphic/structural geometry of these regions.

Characterizing the nature of flow systems in the thrust-fold belt is important for two main reasons.

1. The thrust-fold belt represents a critical part of the overall basin scale flow system. It has been speculated that it could either represent a significant recharge region for many shallow and deep aquifers.
2. Alternatively it may represent closed systems disconnected from deeper undisturbed aquifer(s) eastward. More practically there are large reserves of pooled hydrocarbons trapped in these strata whose distribution and pressures are impacted by formation water flow systems within the thrust fold belt.

So why examine foothills hydrodynamics?

WILDCAT HILLS GAS PLANT

The Wildcat Hills gas plant is located approximately 15 kilometers west of Cochrane along the north bank of the Bow River valley.

The plant is operated by Petro Canada and owned jointly by Shell Canada and Petro Canada Oil and Gas.

The plant is supplied with natural gas via pipeline connected to many wells in the Wildcat Hills gas pools region. The gas feeding the plant is predominantly from the Turner Valley thrust sheets of the Mississippian formation.

The Wildcat Hills discovery was in 1958 with estimated total reserves of 22000 m^3 10/6. The initial pressure was 26 960 kPa at a mean depth of 2948.8 m, the temperature 84 ^{o}C with an average pay of 43.3 m and porosity of 7.5%.

The estimated pool recovery is 88% of the total gas in place.

The natural gas extracted from the fields is processed at the plant before it is ready for commercial sale. In the process hydrogen sulfide (H_2S) is removed from the gas and converted to suphur. Water, carbon dioxide and condensate are extracted from the gas. To protect the surface environment the recovered wastewater is pumped back into the formation while the incinerator stack burns off small amount of residual H_2S.

The plant was designed to process a maximum daily input of 3,200,000 m^3 of natural gas. The plant can produce a maximum of 125 cubic meters per day of stabilized condensate and 250 tones per day of sulfur.

Air and Water Quality Control

The Wildcat Hills Gas plant must adhere to government regulations pertaining to all emissions from the plant.

Air quality is measured at one off site location. A trailer located downwind and to the east of the plant monitors and measures H_2S and SO_2 emissions, wind speed and direction. This is done on a 24 hour a day basis. In addition 12 static monitoring stations measure total H_2S and SO_2 emissions on a monthly basis. All precipitation that falls onto the plant site is collected in runoff ponds. This water is not released until it meets Alberta Environment standards.

Environmental Monitoring

This is a daily ongoing process at the plant. The following programs are in effect.

1. Soil, ph monitoring.
2. Hydrology of Groundwater; study the surrounding subsurface water characteristics and behavior.

Hydrodynamics of Wildcat Hills

The Wildcat Hills Mississippian pool is a first generation play type (Fig.6.4). Initially conceived as being a homogeneous gas pool, later production engineering and consequent hydrodynamic support has delineated the heterogeneity of the structure and sub-dived it into at least five distinct gas columns (Fig. 6.6). Of the five gas columns delineated, four were attributed gas water contacts based on the head of 757.0 m, the water drive behind the pools. Pool number one of Wildcat Hills and Jumping Pound were difficult to delineate other than the application of pressure versus time plottingFrom the regional head map and salinity distribution ascertained for the Wildcat Hills and Jumping Pound gas pools, these pools are similar to the un-deformed Turner Valley distributed across the platform occurring over the 700-900m range (Fig.6.7). The salinity of the waters range from 60,000 - 80, 000 mg/l.

The thrust sheets to the southwest develop in the salinity range of 90,000 - 130,000 mg/l with heads ranging between 1300 - 1600.0 meters (Fig. 6.7). This suggests that there is poor hydraulic communication between this area and the adjacent central zone. The central zone occupies the eastern region of the thrusted strata and is characterized by lower hydraulic heads (800 - 1000.m) with salinity of about 100,000 mg/l.

It is interpreted that the flow conditions within the thrusted strata run parallel to the thrust sheets. The general nature of the thrusted strata suggests that deformation was not maintained along a single structure over great distances. Typical thrusts and associated rollover anticlines tend to plunge and or die out along strike at which point deformation is taken up on a sub-parallel structure either further in or outboard. This structural style has a significant impact on the formation water flow systems. There tends to be poor hydraulic communication in a vertical or a southwest-northeastern direction but perceptibly good hydraulic communication in a Northwest-southeast direction parallel to structural strike. At the regions of a particular structure where it either plunges or dies out, hydraulic communication tends to occur both vertically and in a southwest-northeast direction perpendicular to the structural trend. These are regions (Fig.6.7) where formation water can move in a northeasterly to easterly direction toward the un-deformed section. It should also be noted that at any particular location there can be hundreds of meters of vertical separation between repeated Turner Valley strata. The intervening strata and structures often form hydraulic barriers between Turner Valley aquifers.

WILDCAT HILLS POOLS/FLOW SYSTEM

R.3W5

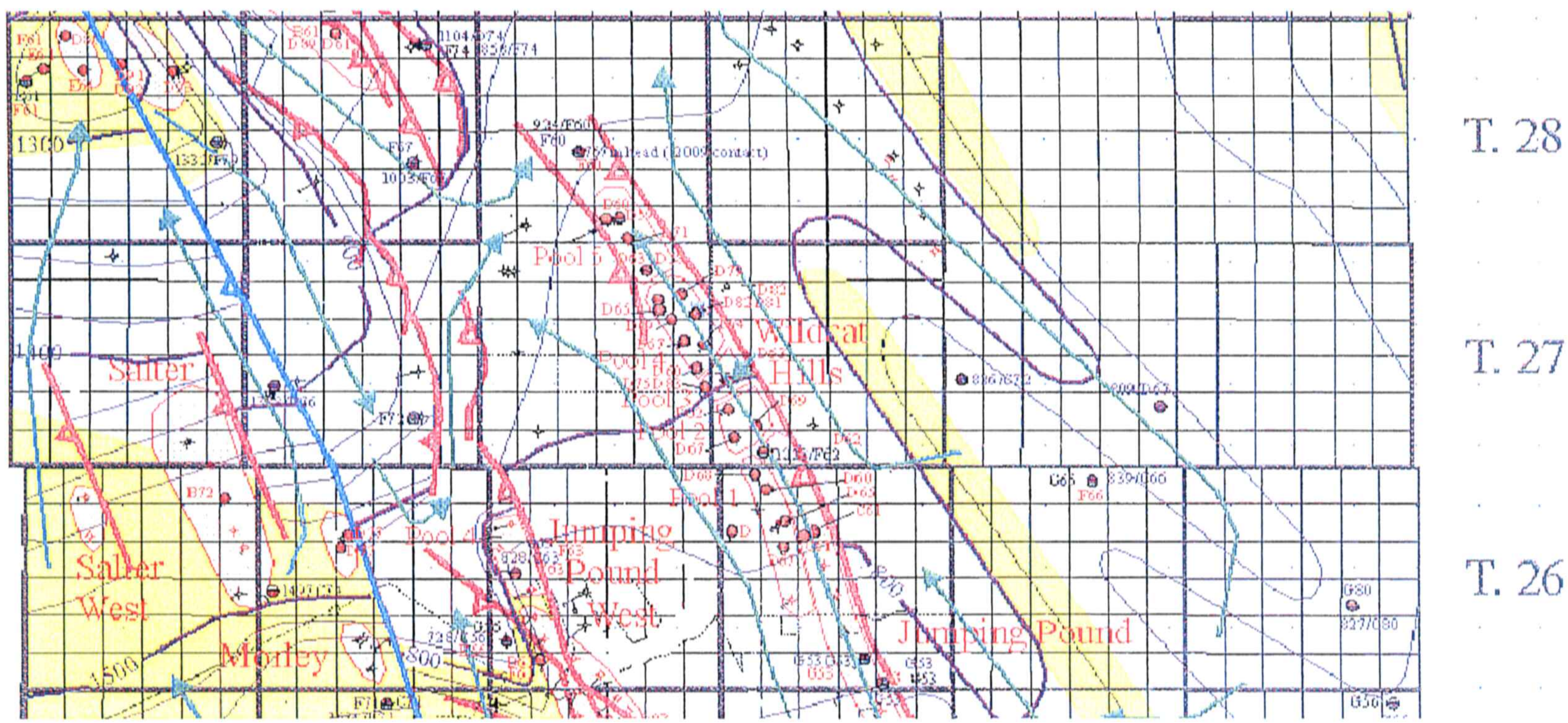


Figure 6.6 Flow direction running parallel to thrust sheets direction changes as sheets plunge.

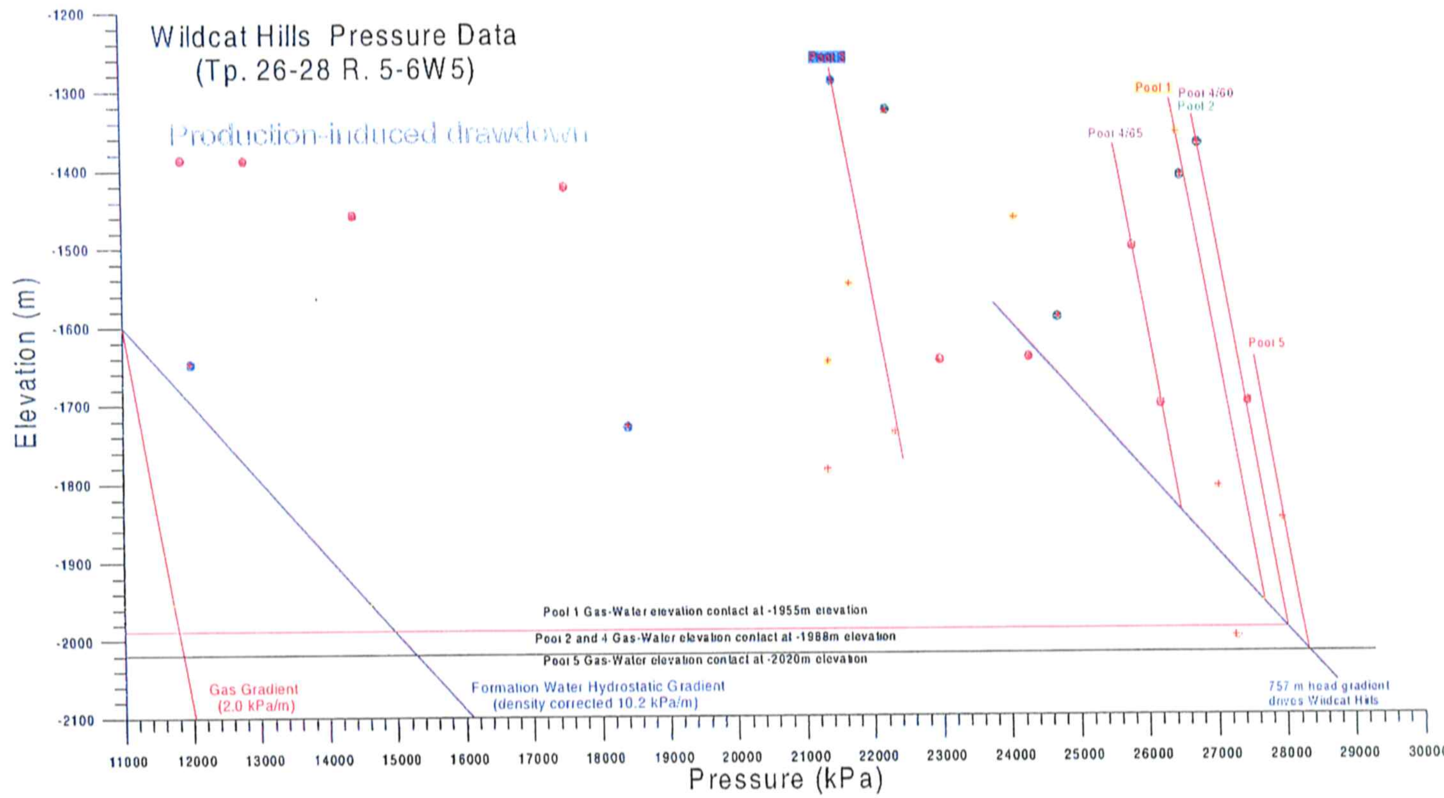


Figure 6.7 Gas columns within Wildcat Hills pool driven by single water drive (aquifer).

Looking westward towards the McConnel Thrust the most westerly thrust running along the entire western flank of the Alberta Basin. On-lapping eastward are several thrusts sheets running parallel to the Panther thrust for which we are positioned (Fig.6.1). Between these two thrusts are the lesser Salter, Hunter Valley and Panther River sheets. Significant gas pools have been found here at Mississippian level. East of our current position is the Benjamin pool.

Flow systems west of the Panther Sheet are greater than 1300 meters of hydraulic head running parallel to that sheet (Fig.7.1). The pool sizes here are significantly larger. As of 1992 the total reserves were projected at 9,411 10^6 m^3 with an average pay thickness of .05 with an average pay thickness of 50.0 m. Panther river has one gas column.

Benjamin Creek in comparison had a projected reserve of 4 688 10^6 m^3 with an average porosity of .056 with a thickness of 19.2 m.

The Benjamin pool is structurally complex with up to three separate repeat sections from which there may be production (Fig 7.2). There are three separate pools at Benjamin with one being in the upper thrust and the other two in the middle thrust sheet. The flow system at Mississippian level here, flows parallel to strike and may escape eastward as the thrust plunges. Flow potential would appear to escape around Benjamin complex and migrate eastward through the un-deformed north section of the Wildcat Hills sheet.

Upon examinaing total stratigraphic package here, permeable Cardium to Turner Valley the pressure suggests the distribution of several fluid gradients (Aquifers) suggesting possible vertical communicatio (Figs. 7.3, 7.4). Three water gradients are apparent.

The water chemistry here is approximately 20 000 mg/l higher (Fig.7.5) than the Wildcat Hills system to the southeast (Fig.7.6).

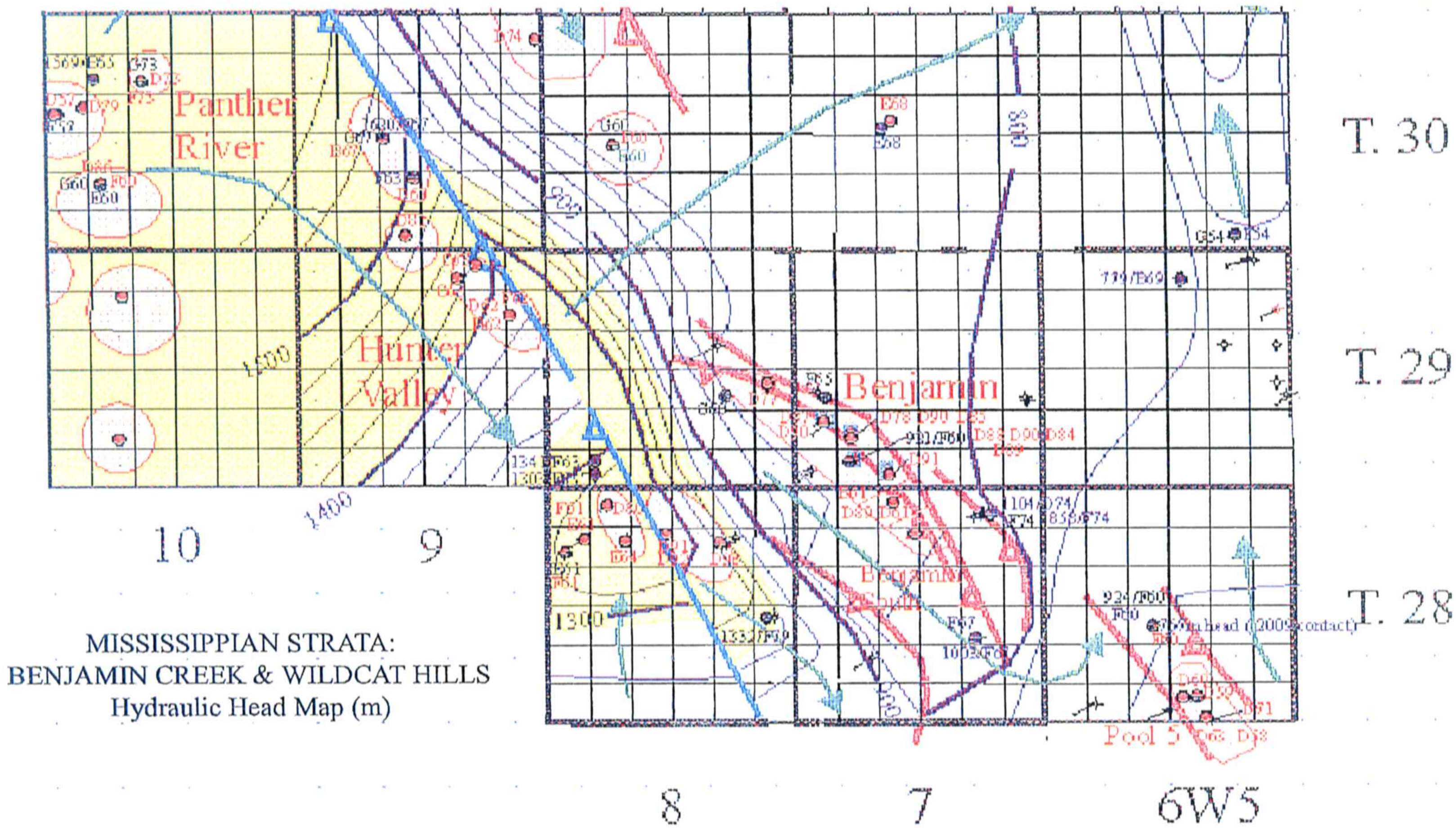


Figure 7.1 Flow pattern at Benjamin. Lowest head equivalent to main platform system.

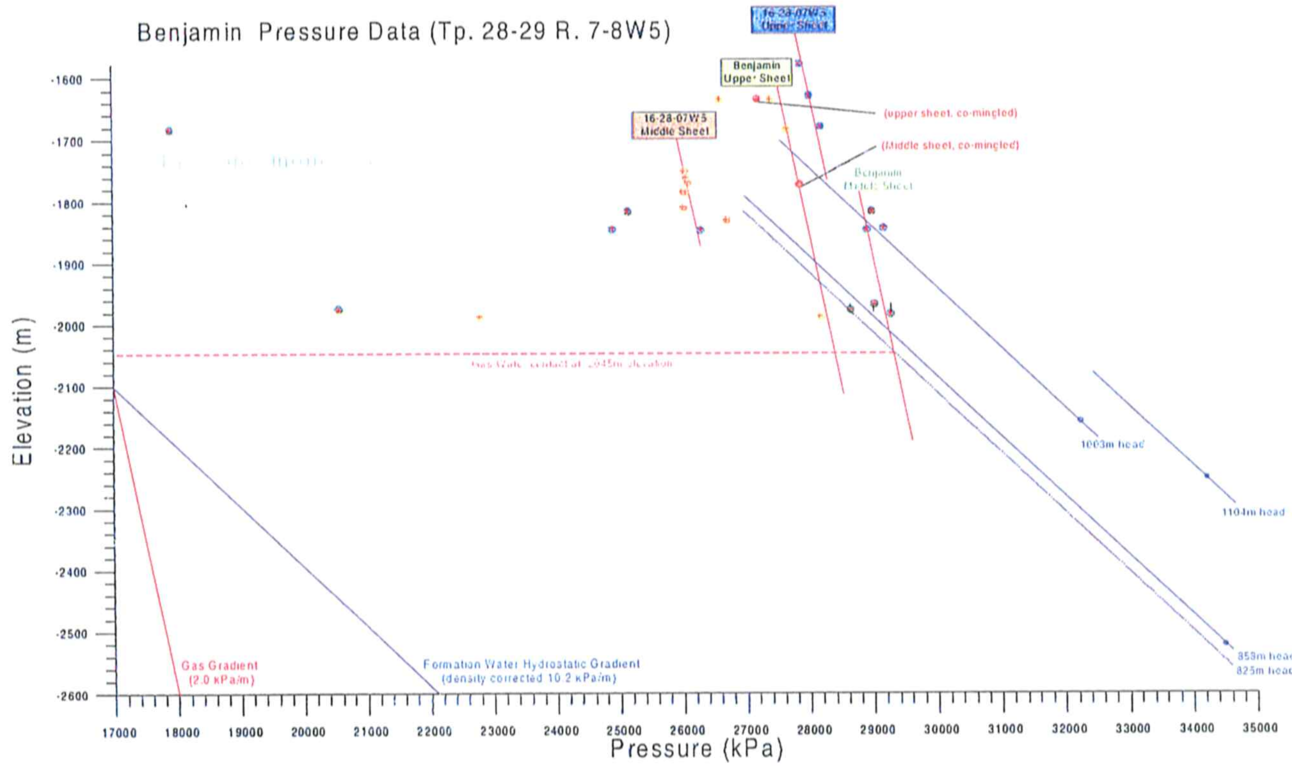


Figure 7.2 Repeat sheets, separate sheets = separate gas columns = differential head values.

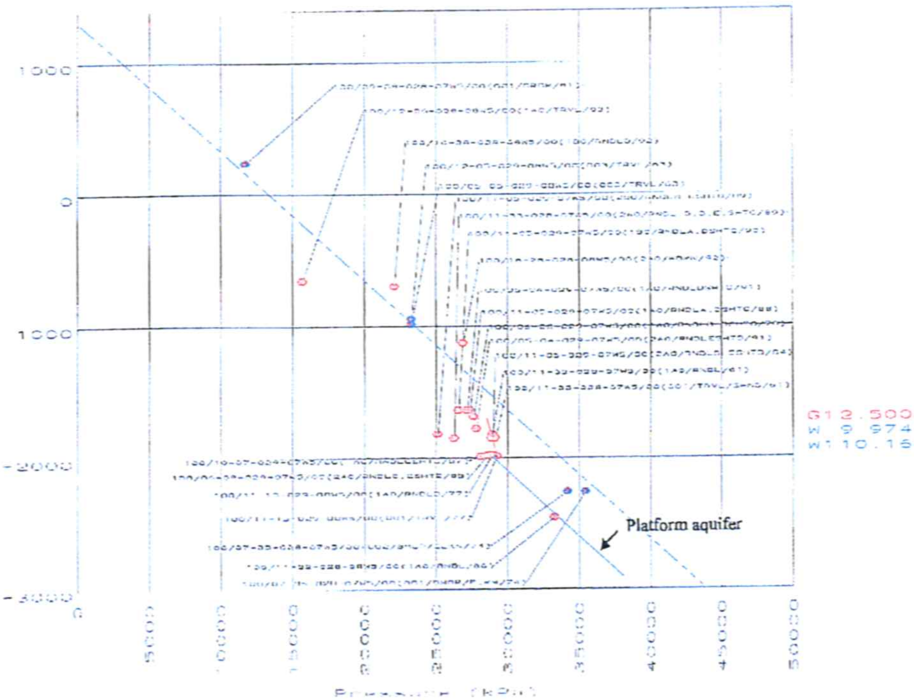


Figure 7.3 Benjamin-Wildcat T28-29 R7-8W5

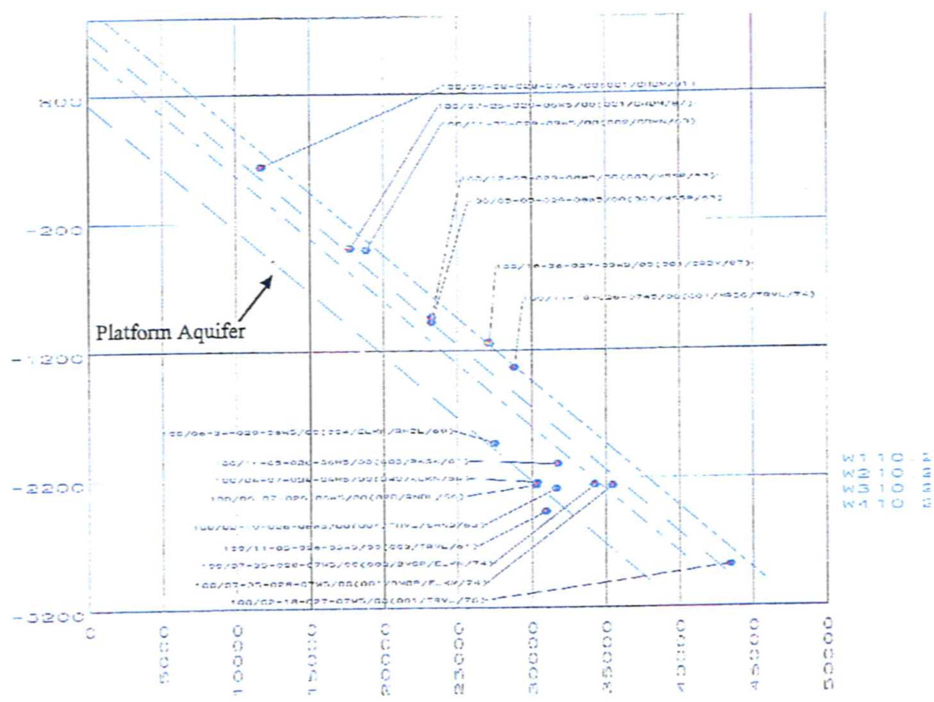


Figure 7.4 Benjamin T26-28 R5-9W5

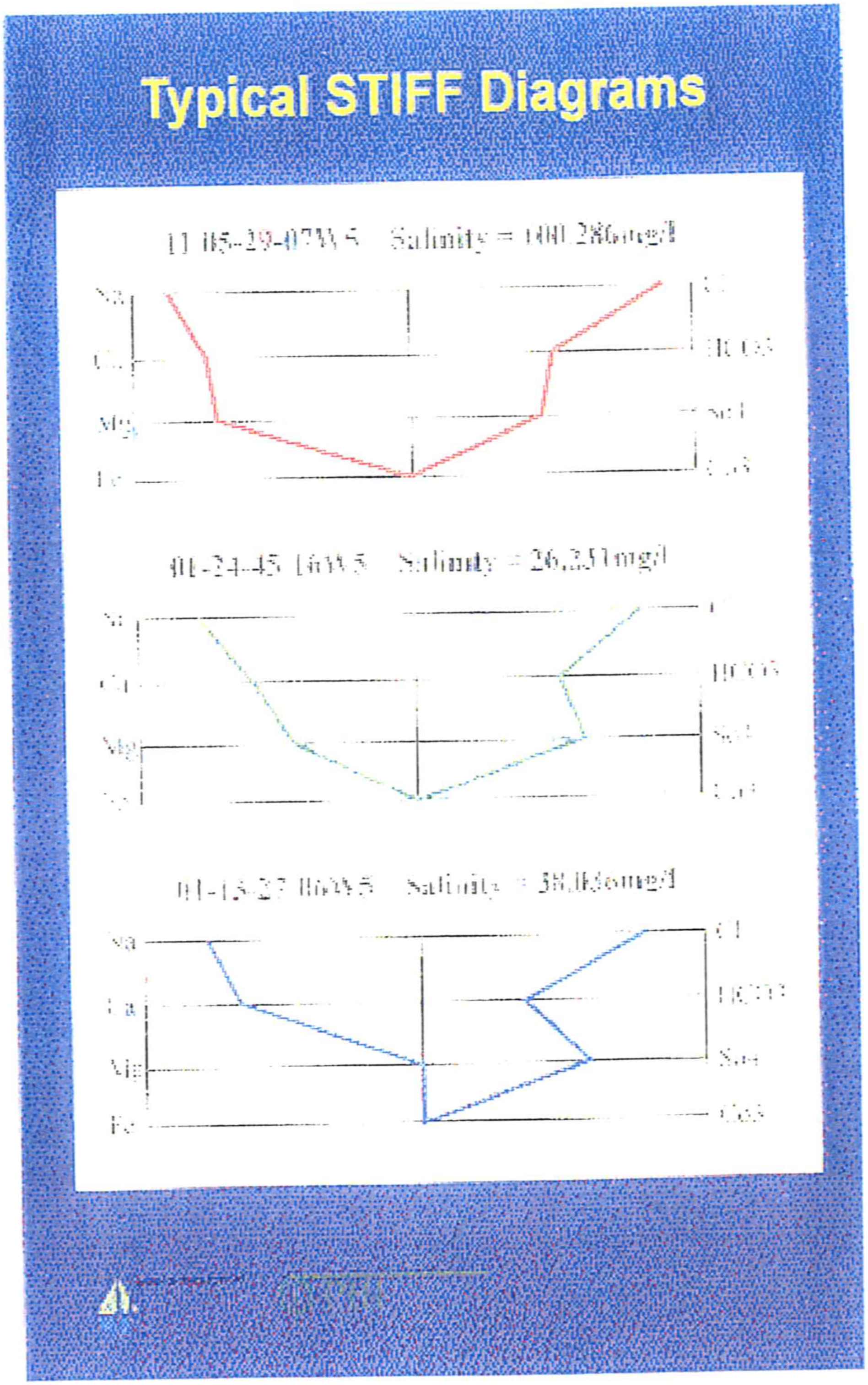


Figure 7.5 Typical formation waters.

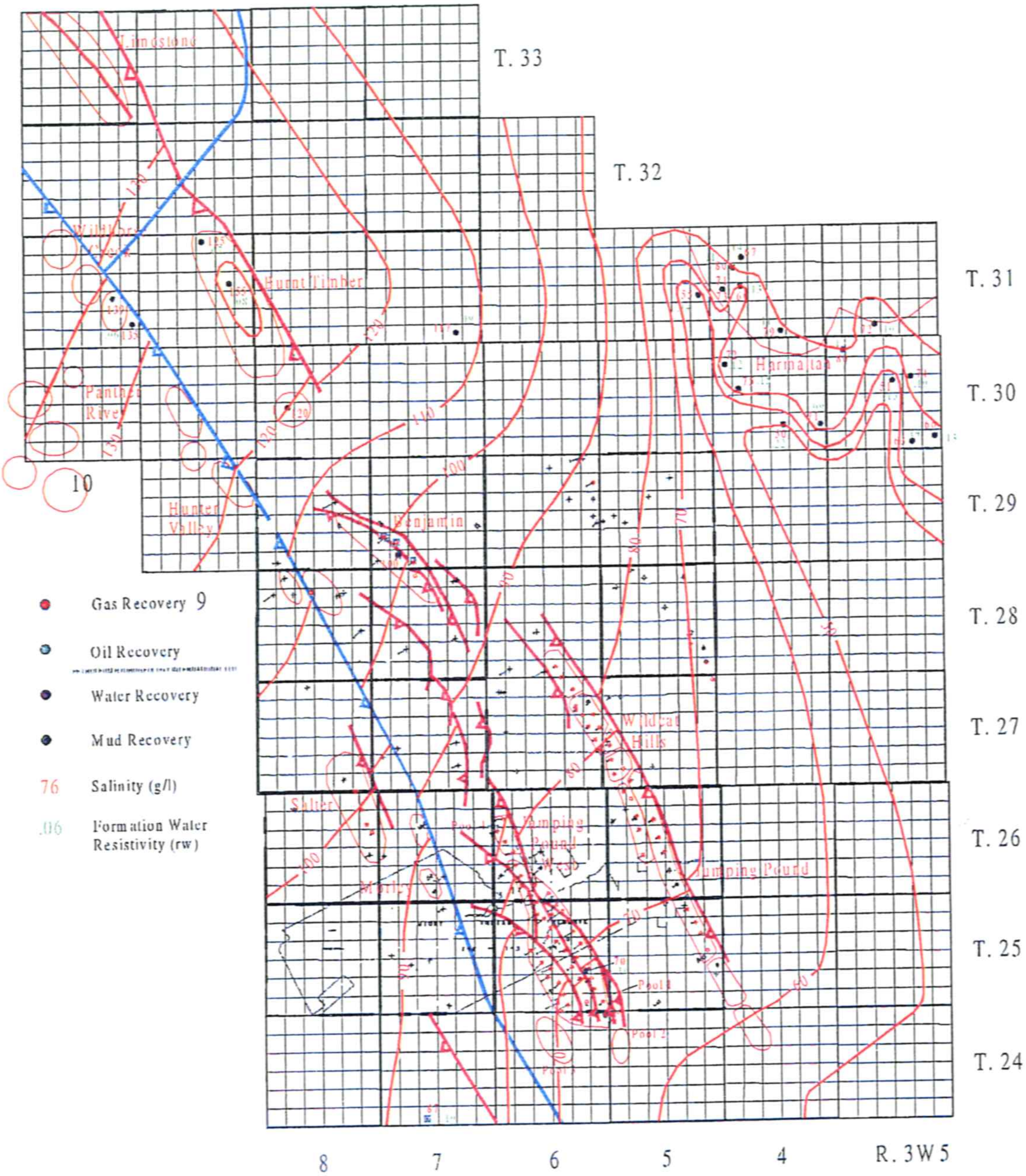


Figure 7.6 Mississippian strata: Benjamin Creek and Wildcat Hills salinity (g/l)

Objectives

At this stop we will review the present basin-scale water flow systems of the Alberta Basin and consider how hydrodynamics may have impacted the origin of the Alberta oil sands. Hydrodynamics has potentially played a key role in three aspects: oil migration, alteration and trapping.

Introduction

Key issues relating to the origin of the Alberta oil sands include:

- the time and place of oil generation
- the carrier beds and migration paths linking the oil kitchen to the accumulation sites
- the time of accumulation and mechanism of trapping
- the processes that altered conventional oil to bitumen

Source Rock

The Exshaw Formation of upper Devonian-lower Misssissippian age has been identified as the major source for the oil sands as well as most conventional oils in the Lower Cretaceous of central and southern Alberta (see Fowler in this field guide – Redwater stop). The approximate area where the Exshaw Formation source rock is thermally mature in western Alberta and northeast British Columbia is shown on Figure 8.0.a. Figure 8.0.b shows a cross-section along the Athabasca oil sands migration pathway.

It is notable that the Peace River deposit overlies the Jurassic subcrop. The Buffalo Head Hills oil sands (the scattered pools in north central Alberta) and the Wabasca oil sands (the west-most bulge of the outline labeled "Athasbasca") both overlie the Exshaw subcrop. The Athabasca and Cold Lake oil sands and the Lloydminster heavy oils overlie Devonian subcrops between 100 and 300 km to the east of the Exshaw subcrop.

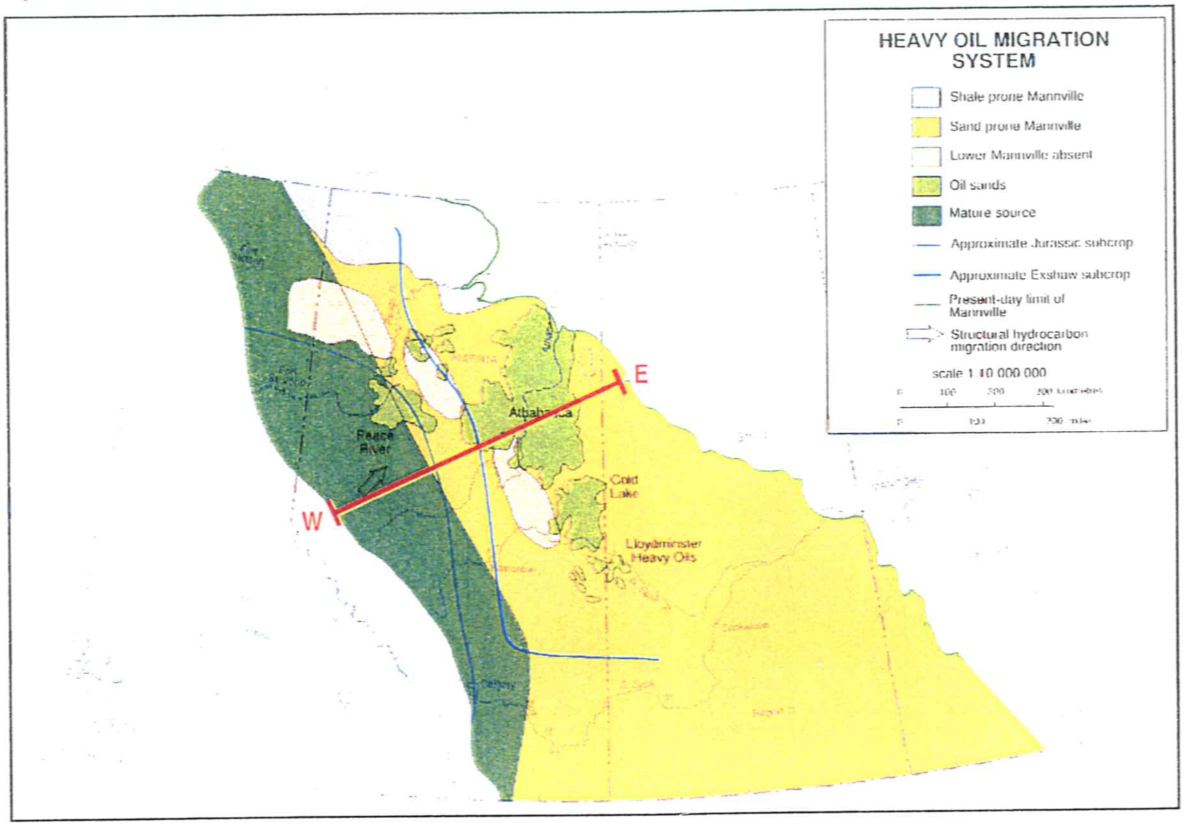
1. Potential Hydrodynamic Impact on Oil Migration

After expulsion from a thermally mature source rock, oil migrates along bedding in a permeable carrier bed. Oil is driven updip by buoyancy but is also entrained in the flow of formation water (Hubbert 1940, 1953). Updip water flow accelerates oil migration and downdip flow retards migration. Water flow along strike will modify the direction of oil migration. This procedure

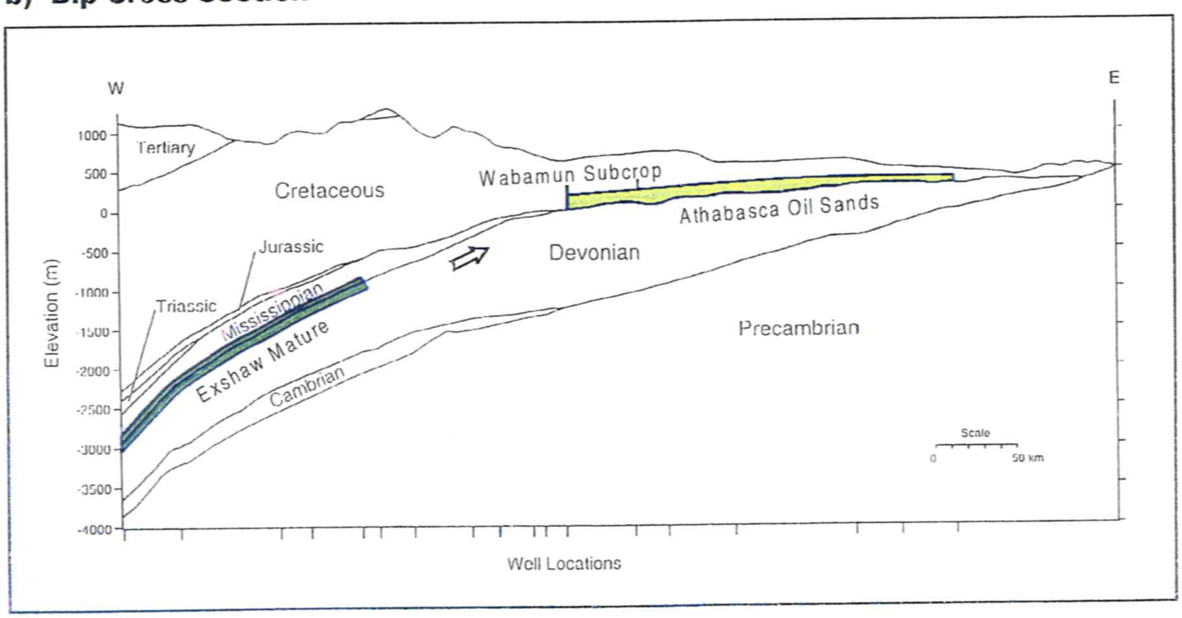
Numerous regional scale hydrogeological studies have been conducted in the Alberta Basin over the last thirty years culminating in the Hydrogeological Atlas of the Western Canada Sedimentary Basin (Rakhit Petroleum Consulting Ltd., 1996). The work conducted to date has revealed the major flow systems that exist in the Alberta Basin at the present day. Bachu (1995) has summarised these flow systems in Figure 8.1, two of which are particularly relevant to the oil sands:

The deepest flow system in the oldest strata in the basin (system 4 in Figures 8.1.a and 8.1.b) exhibits updip water flow directed from southwest to northeast. This system includes the Paleozoic source rock and carrier beds that charged the oil sands

a) Plan View



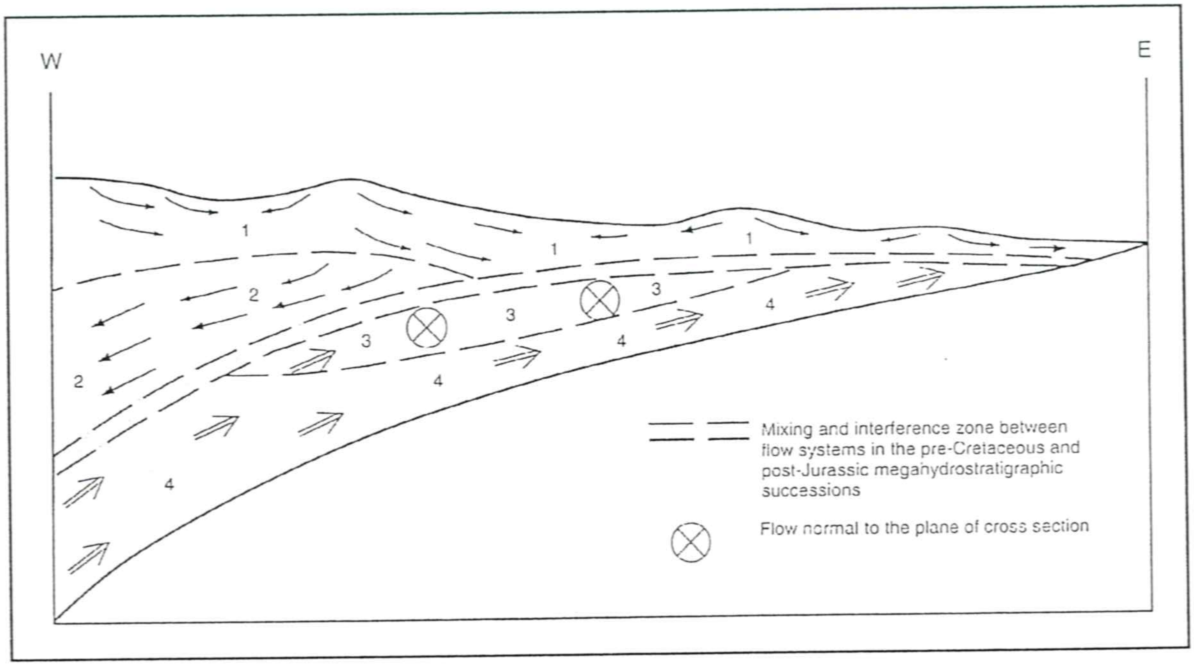
b) Dip Cross-Section



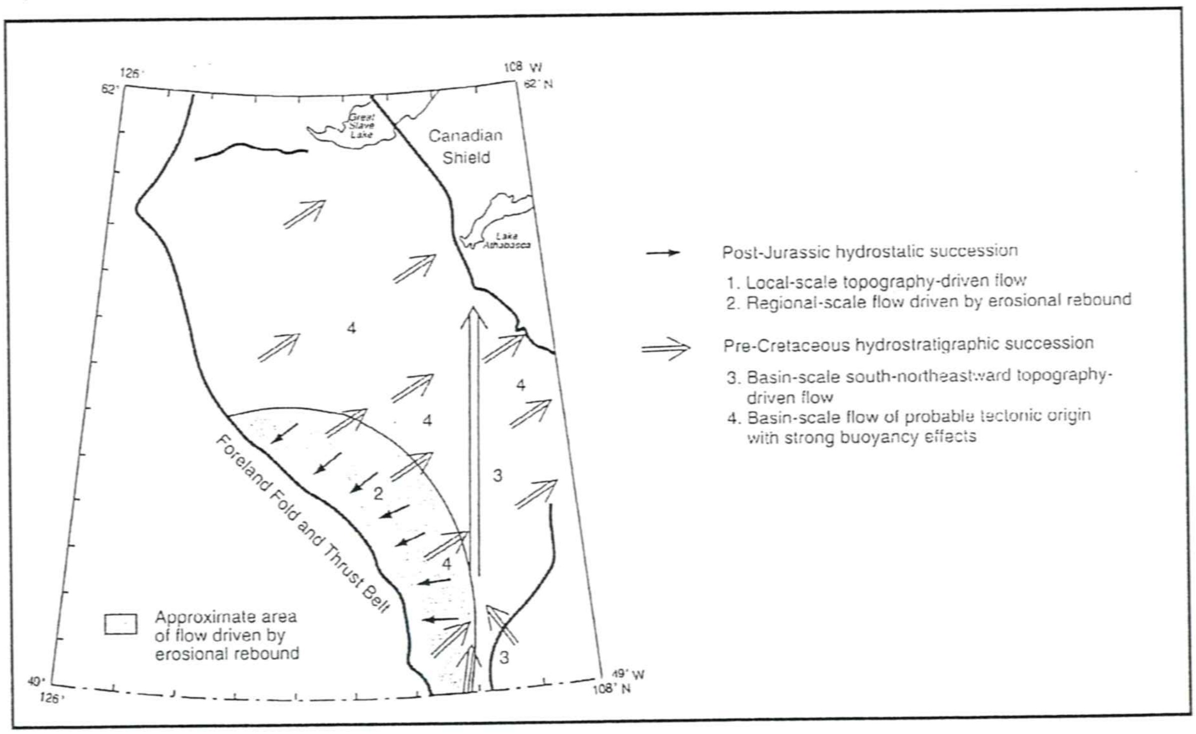
From Creany et al., 1994 and Bachu, 1995

Figure 8.0 - Postulated migration paths for oil sands, Alberta basin

a) Dip Cross-Section



b) Plan View



From Bachu, 1995

Figure 8.1 Diagrammatic patterns of water flow in the Alberta Basin

a) and consequently potentially impacted the initial stage of secondary oil migration in upper Devonian/Mississippian carrier beds to the sub-Cretaceous unconformity.

b) The shallowest system is a zone of topographically driven water flow (system 1 in Figures 8.1.a and 8.1.b). Meteoric water recharges at topographic uplands moves vertically downwards across weak aquitards, then flows laterally to discharge at the lowest elevations of the land surface in the major river valleys. This system extends from the land surface down to a maximum depth of about 1 kilometre. It includes the Lower Cretaceous carrier and reservoir beds for the Athabasca oil sands and consequently potentially impacted the latter stage of secondary oil migration as well as oil entrapment and degradation.

Clearly water flow systems in the Alberta Basin have not remained as they are today over geological time. Since oil migration occurred many tens of millions of years ago it is necessary to consider how flow may have changed over time. Figures 8.2, 8.3 and 8.4 illustrate schematically the possible evolution of the basin scale flow patterns over the period relevant to the migration and emplacement of the oil sands (Underschultz and Allan 1995).

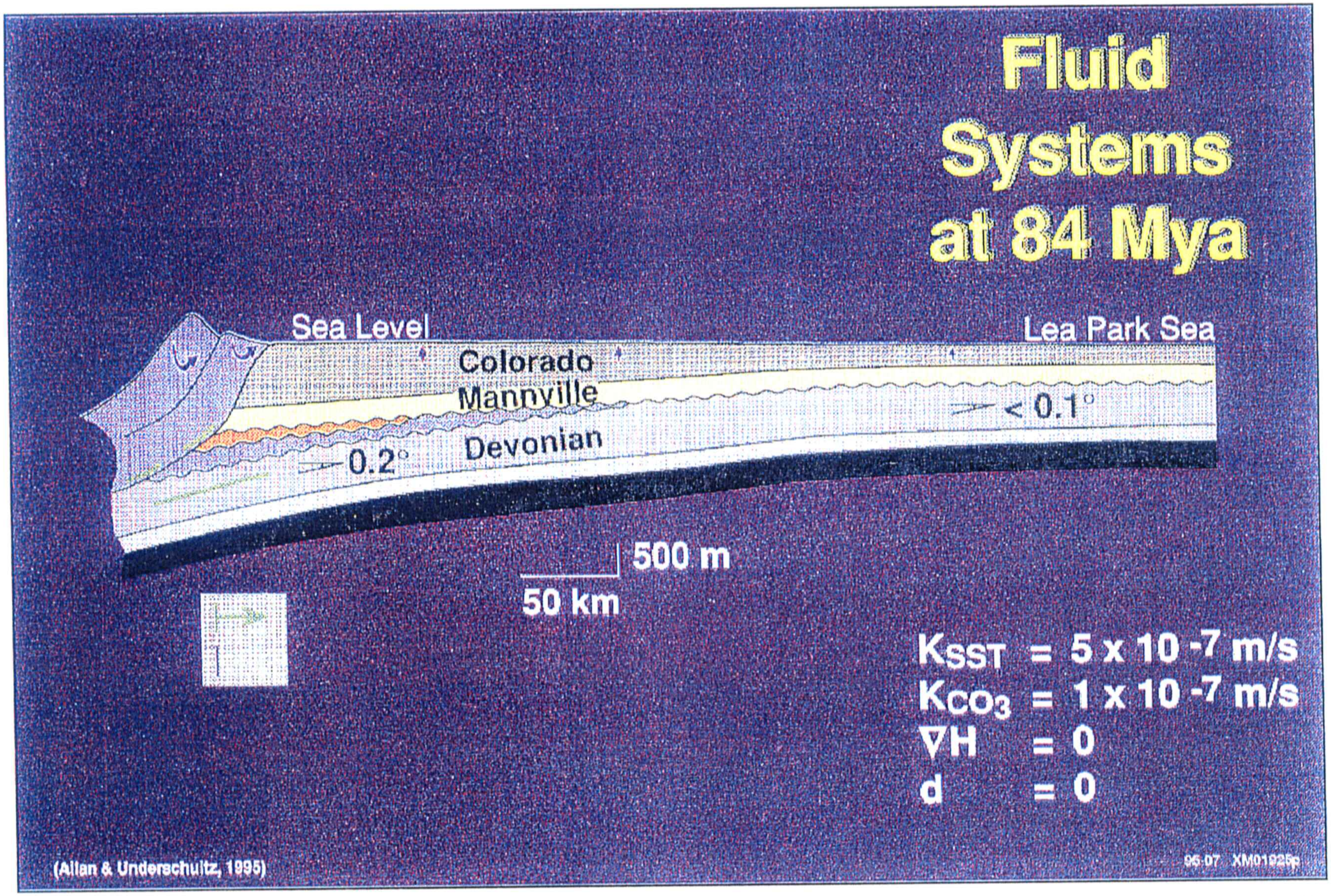
Figures 8.2, 8.3 and 8.4 depict possible fluid systems at 84, 67 and 30 Ma respectively. The main oil buoyancy and hydrodynamic driving forces for oil migration are indicated based the stratigraphic and structural geometry of the basin reconstructed for each time. The relative magnitudes of driving forces are shown as arrows in the boxes located below the cross-sections (the buoyancy driving force on top, hydrodynamic driving force below). Dark bands indicate the position of oil within various formations and the arrows indicate the main water flow directions. Below are the notes from (Underschultz and Allan 1995) corresponding to each snapshot.

84 Mya

- Mainly a compaction driven flow system
- Minor topography-driven flow in the extreme west
- Hydrocarbon generation in Paleozoic strata to the west
- Some hydrocarbons trapped in upthrust Paleozoic strata
- Small buoyancy driving force due to low structural dip
- Negligible hydrodynamic driving force

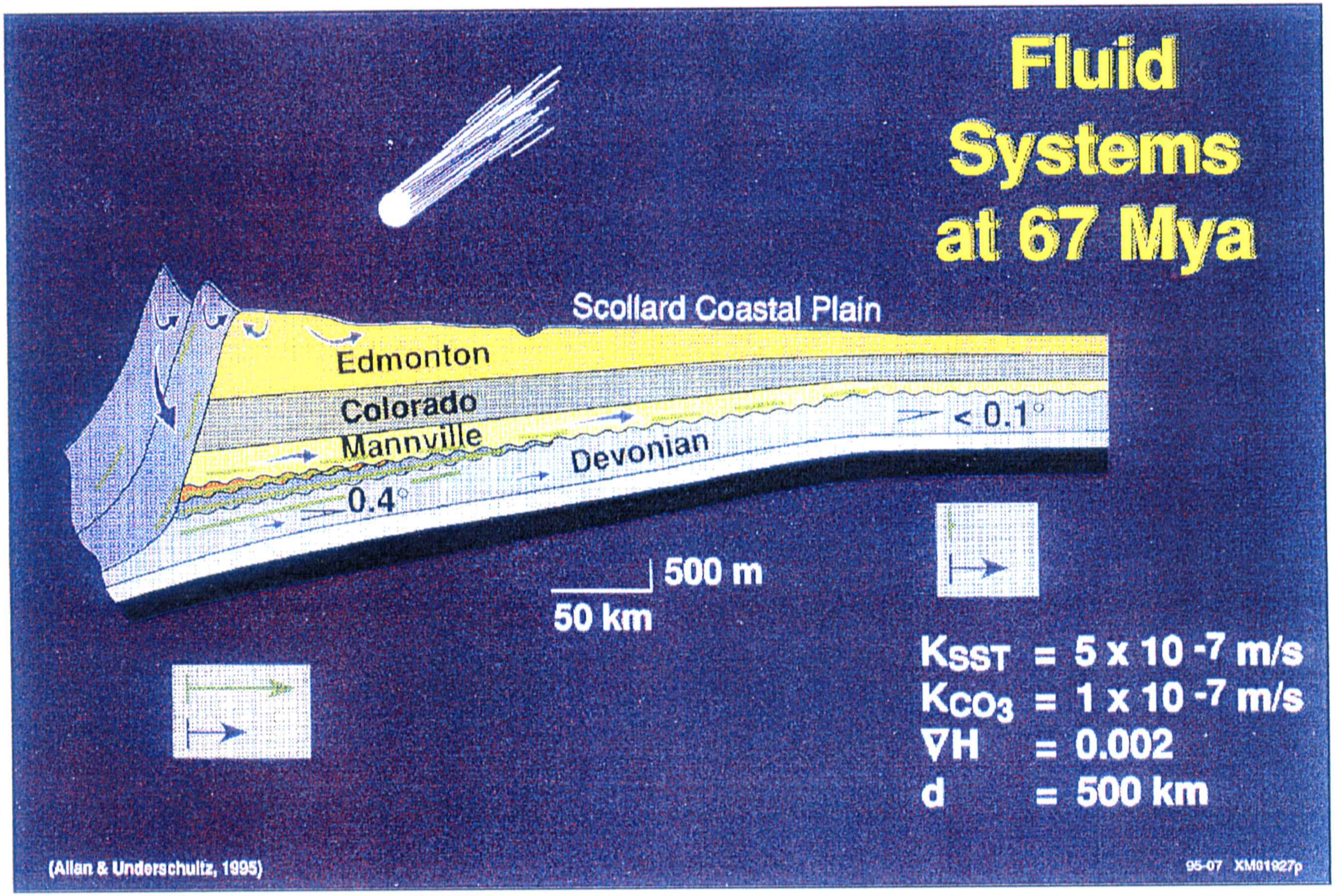
67 Mya

- Local scale topography-driven flow in post-Colorado strata
- Initiation of intermediate to regional scale topography-driven flow in pre-Colorado strata
- Hydrocarbons migrating slowly updip in Paleozoic strata
- Hydrocarbons accessing Lower Cretaceous sands via deformation in the west migrate relatively quickly updip
- Strong buoyancy driving force in the west due to steep dip of carrier beds
- Negligible buoyancy driving force in the east



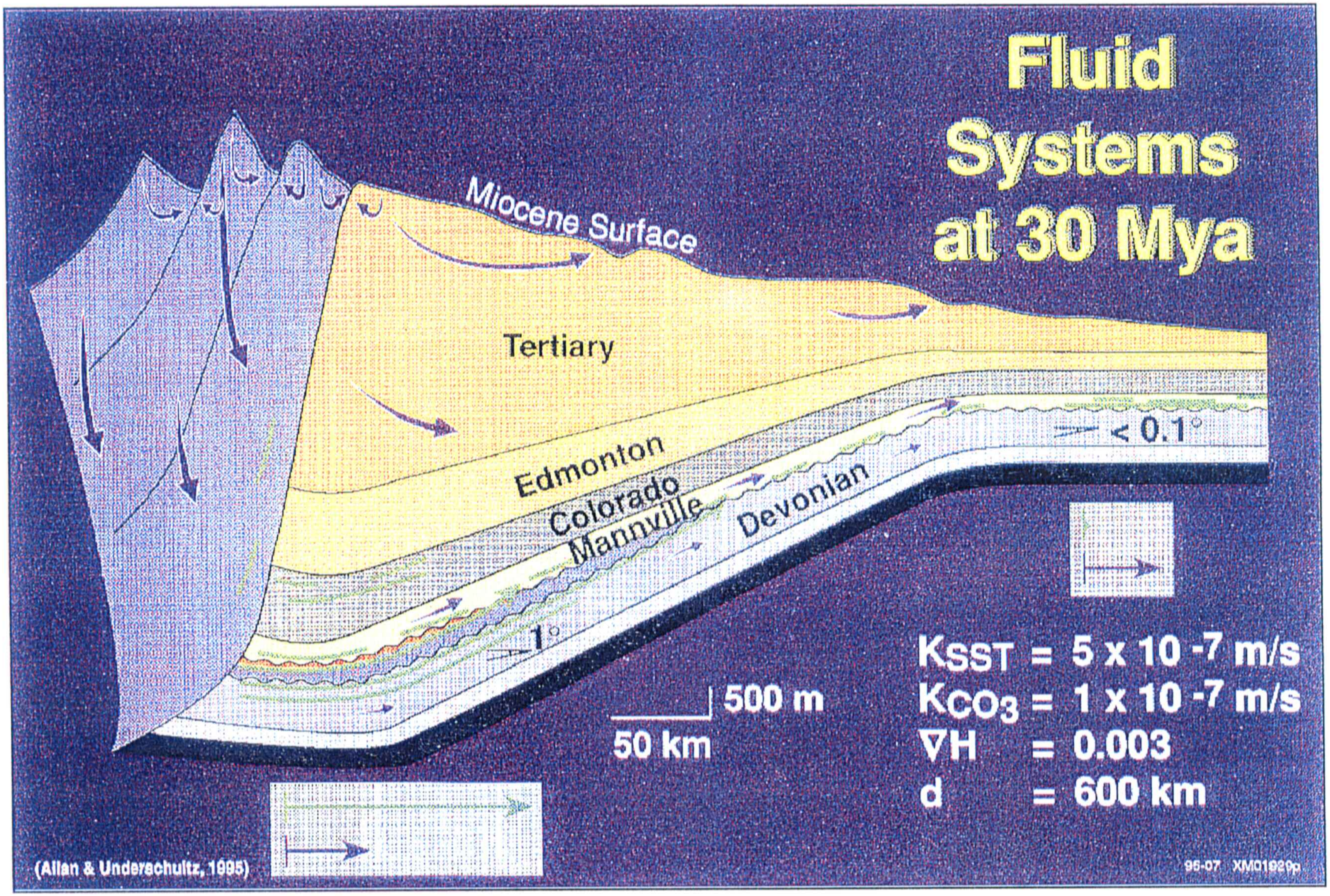
From Allen and Underschultz, 1995

Figure 8.2 Diagrammatic cross-section showing oil flow in the Alberta basin at 84 ma.



From Allen and Underschultz, 1995

Figure 8.3 Diagrammatic cross-section showing oil flow in the Alberta basin at 67 ma.



From Allen and Underschultz, 1995

Figure 8.4 Diagrammatic cross-section showing oil flow in the Alberta basin at 30 ma

- Moderate hydrodynamic driving force across the entire basin

30 Mya

- Local topography-driven flow in post-Colorado strata
- Intermediate to regional scale topography-driven flow in pre-Colorado strata
- Hydrocarbon generation in Cretaceous strata
- Hydrocarbons migrating throughout the system with pooling at the eastern edge of the basin
- Strong buoyancy driving force in the west due to steep dip of carrier beds
- Negligible buoyancy driving force in the east
- Moderate hydrodynamic driving force across the entire basin

Building on the water flow equation introduced at Stop 5, we can estimate the rate of oil migration at each of the time steps indicated by Figures 8.2, 8.3 and 8.4. Following the method presented by Garven (1989):

$$v_{oil} = -(K_{oil}/n * \mu/ \mu_{oil}) [(\rho_w/\rho_{oil} \text{ grad } h_w) + (\rho_w - \rho_{oil} / \rho_{oil}) \text{ grad } z]$$

where v_{oil} is the oil velocity, K_{oil} is the hydraulic conductivity of the carrier bed, n is the carrier bed porosity, μ and μ_{oil} are the oil viscosity at standard and reservoir conditions respectively, ρ_w and ρ_{oil} are the water and oil density at reservoir conditions, grad h_w is the hydraulic head gradient and grad z is the elevation gradient. The table below contains the pertinent data for each migration "snapshot" and the calculated oil velocities.

Time	Carrier Bed	oil velocity km/my	Depth m	Temp deg C	Pressure kPa	k mD	porosity frac	viscosity µw cP	viscosity µo cP	density ρo g/cc	density ρw g/cc	head gradient m/km	slope m/km
84 Ma	Paleozoic	**26**	1,500	65	15,000	10	0.2	0.45	0.70	0.72	1.01	0	3.5
	L. Cretaceous	**15**	600	38	6,000	50	0.3	0.58	0.98	0.73	1.02	0	0.9
67 Ma	Paleozoic	**152**	2,500	95	25,000	10	0.2	0.35	0.50	0.70	0.99	2	7.0
	L. Cretaceous	**150**	1,000	50	10,000	50	0.3	0.55	0.90	0.73	1.01	2	0.9
30 Ma	Paleozoic	**654**	6,000	200	60,000	10	0.2	0.20	0.25	0.63	0.92	3	17.5
	L. Cretaceous	**283**	1,500	65	15,000	50	0.3	0.45	0.70	0.72	1.01	3	0.9

The major uncertainty in these calculated velocities is the permeability and porosity of the carrier bed.

The oil used for these calculations is Morinville Lower Mannville crude, a 39 °API oil with a gas/oil ratio of 54 m3 gas/m3 oil. This is assumed to represent the character of the oil sands crude oil prior to degradation. The formation water modelled is brackish water with a salinity of 30,000 mg/l.

At 84 Mya with no hydrodynamic driving force, the oil migration velocity in the Paleozoic carrier beds is 26 km/m.y. In the gently dipping Mannville carrier beds the velocity is reduced to 15 km/m.y. Assuming for simplicity a migration distance of 250 km in both carrier beds, the travel time for oil to move across the basin is 9 m.y in the Paleozoic and 17 m.y. in the Mannville. This scenario indicates that despite the relatively weak driving forces (the hydrodynamic drive is solely from compaction and oil buoyancy is limited by the gentle inclination of the carrier beds) oil migrates across the basin in less than 30 m.y.

At 67 Mya with a mild hydrodynamic driving force and a steeper dip in the Paleozoic section, the oil migration velocity in both the Paleozoic and Mannville carrier beds has increased to 150 km/m.y. Still assuming a migration distance of 250 km in both carrier beds, the travel time for oil to move across the basin is now just 4 m.y.

At 30 Mya with a stronger hydrodynamic driving force and a steeper dip in the Paleozoic section, the oil migration velocity in the Paleozoic carrier beds has increased to 654 km/m.y. In the gently dipping Mannville carrier beds the velocity is now 283 km/m.y. Assuming a migration distance of 250 km in both carrier beds, the travel time for oil to move across the basin during this snapshot is less than 2 m.y.

These results show that since the development of a regional hydraulic gradient across the basin, the updip flow of water will have accelerated the rate of oil migration out of the deep basin. In northeast Alberta where the dip of the oil sands carrier beds is subdued, water flow has been the dominant driving force for lateral migration. However, water flow is not <u>required</u> to account for the oil at Athabasca because the buoyancy-driven oil migration rate has been sufficient since the Foreland Basin developed in late Jurassic to early Cretaceous time.

2. Hydrodynamic Impact on Oil Alteration

Assuming that oil migrates as a separate phase in water wet carrier bed, water washing and biodegradation are the main processes that transform light or medium garvity oil into heavy oil and bitumen. **Water-washing** of oil flowing past water, or of water flowing past oil can result in the removal of the more water soluble components which are the low molecular weight hydrocarbons. Water washing over extensive time periods can remove hydrocarbons up to C15 (Hunt 1995, p. 422) tending to increase the oil density, in extreme cases resulting in un-producible heavy asphaltic crude. Bacterial microbes that require oxygen, water and mineral nutrients for sustenance effect **biodegradation**. They can live at temperatures up to at least 75 ^{o}C and pressures up to 170 MPa (25,000 psi) corresponding to hydrostatic pressures at depths up to 3.5 km. Aerobic bacteria at the surface attack n-paraffins (C16-C25) first then higher range paraffins and other components. Bailey et al (1973) have shown that both aerobic and anaerobic bacteria can be effective, but that aerobic bacteria seem to be more efficient. According to Chapman (1983), movement of groundwater from the land surface to the migrating or accumulating crude oil would seem to be an essential condition for biodegradation.

The processes of water washing and biodegradation can account for the progressive change in character of Mannville oils from central Alberta to the eastern basin margin (Deroo et al, 1974). Jardine (1974) noted a systematic increase in oil density from Lloydminster through Cold Lake to the Athabasca area corresponding to a freshening of the formation water with proximity to the basin edge. This relationship would appear to support recent degradation of the oil, i.e., late in the geologic history of the basin. On the other hand (since independent evidence suggests that degradation occurred some 100 m.y ago soon after deposition of the McMurray) it may be that the hydrodynamics and water chemistry we see today are long-lived patterns. Perhaps the flow systems that we see today have not changed appreciably since the time of initial migration.

3. Hydrodynamic Impact on Trapping

The trap mechanism at Athabasca remains a subject of debate since the oil sands pass updip into water wet sands northeast of the town of Fort McMurray. Structure on the sub-Cretaceous unconformity in the Athabasca area reveals some reversal of dip created by salt solution in the underlying Prairie Evaporite but no strucutral closure exists. A number of authors have noted that the structural and stratigraphic trap capacity for the Athabasca oil sands is insufficient to account for the huge volume of reserves in place (e.g., Jardine 1974, Deroo et al 1974, Wightman et al, 1995). It has been suggested that the trap mechanism may have been degradation of the oil as it migrated through the McMurray sands, which contained meteoric water infiltrating into the shallow eastern edge of the basin. As the oil migrated into the zone of infiltrating meteoric water it would be subject to water washing and biodegradation and would progressively lose light molecules, becoming heavier and more viscous, eventually being frozen in place as bitumen.

A model of degradation during oil migration resolves one significant problem for any post emplacement degradation model. The high oil saturation (hence low relative permeability to water) at the top of a thick oil pool precludes water entry. The average pay thickness in the Athabasca Mining Area (Jardine, 1974) is 32 m or 105 ft. Active and continuous influx of meteoric water is required to supply the oxygen required to maintain an aerobic bacterial colony (Chapman, 1983). Any bacteria isolated within the oil column in the pendular water around sand grains would expire through lack of oxygen before appreciable biodegradation could take place. A question for any post-emplacement degradation scenario is how could the upper part of a 30 m thick oil column have been biodegraded if water could not penetrate there to maintain the bacteria?

The syn-migration degradation model also supports the early degradation of the oil as indicated by the unconsolidated nature of the McMurray sands. Degradation occurred at the time of migration, which was early enough after the deposition of the sands that no cementation had yet taken place.

Finally this model explains presence of water wet reservoir east of and updip from the present bitumen edge (Wightman et al, 1995). No stratigraphic pinch-out was required because the oil simply froze up within good quality reservoir.

This model suggests that the oil at Athabasca would have been lost to updip outcrop but for the hydrodynamic system that controlled the biodegradation.

The present day pattern of water flow in the Fort McMurray area has been mapped in detail to evaluate the present day hydrogeology for a hearing at the Alberta Energy and Utilities Board, concerned with the impact of present shallow gas production on future bitumen production (AEUB, 2000). The final figures presented here are from that study. Figure 8.5 shows the ground surface topography and Figure 8.6 shows the potentiometric surface in the Wabiskaw-McMurray sands. The close correspondence of these surfaces indicates that the water table (a muted replica of the ground surface topography) controls the groundwater flow pattern. Meteoric water is recharging in the upland areas and discharging in the river valleys. The flow pattern is confirmed by the cross-sections shown in Figure 8.7. Figure 8.8 shows the suite of hydraulic head maps created for the major Cretaceous aquifers in the area. In order of increasing depth the four major Cretaceous aquifers are the Grand Rapids the Clearwater, the Wabiskaw-Upper McMurray (above the bitumen) and the Basal McMurray-Devonian (below the bitumen). Note the progressive decrease in head with depth in the area, which provides the gradient that drives groundwater vertically downwards. For each aquifer, the hydraulic head is at a maximum under the uplands and decreases laterally towards the river valleys. Figure 8.9 is a diagrammatic structural cross-section illustrating of the flow patterns.

Long term flow patterns such as these provide a mechanism for introducing biodegrading bacteria into the oil sands reservoir and providing the oxygenated water required for their survival.

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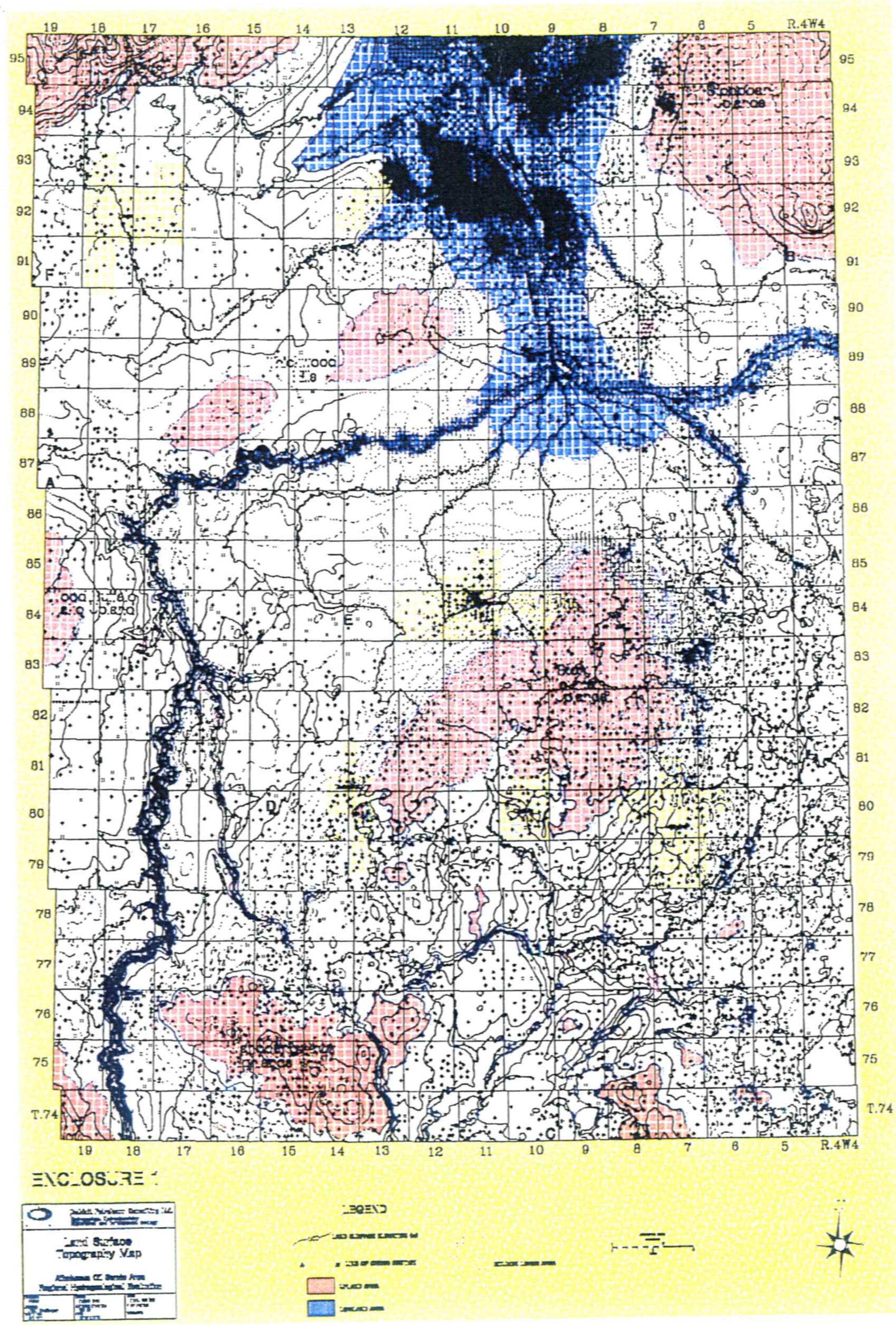
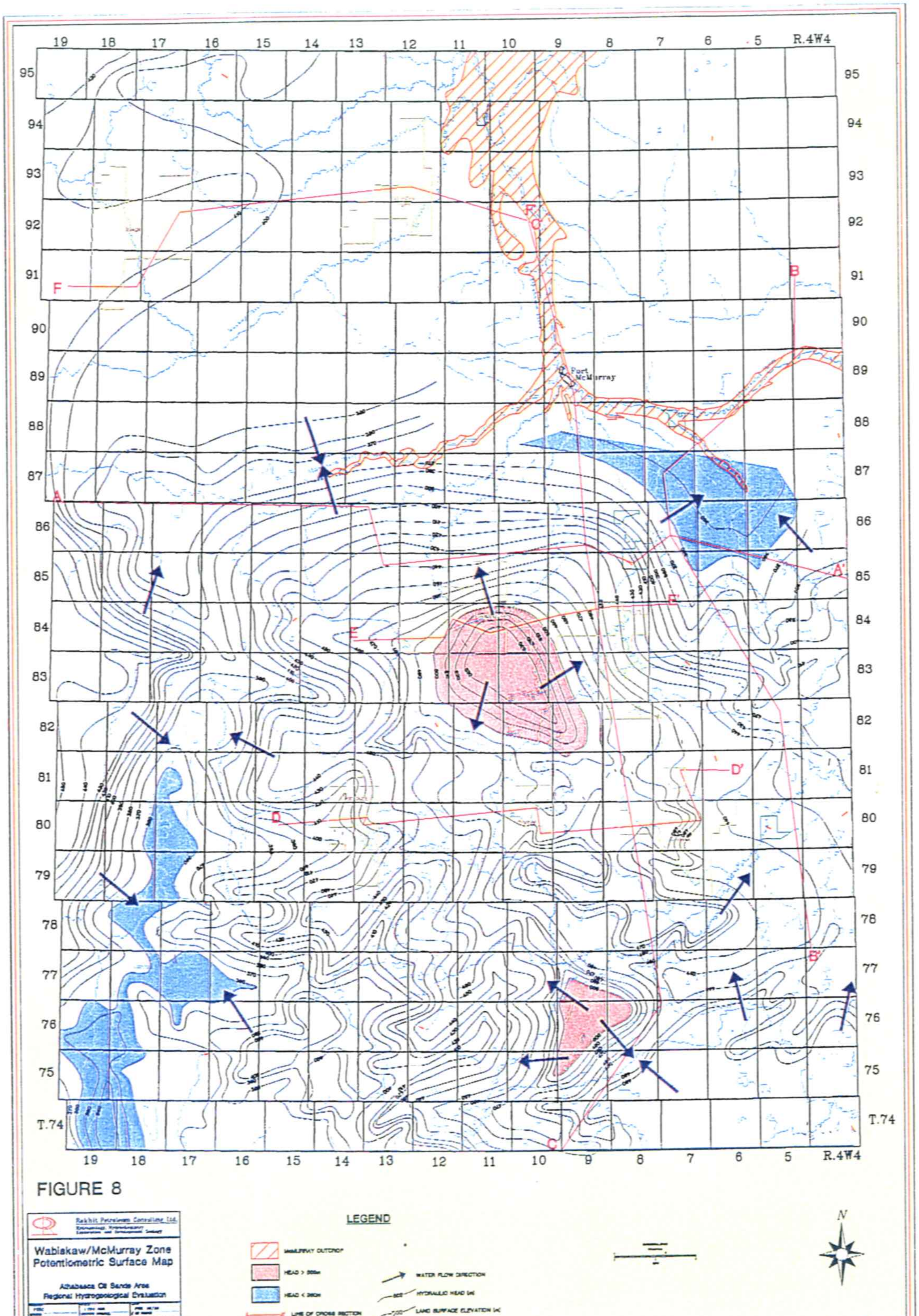


From Rakhit Petroleum Consulting Ltd., 1999

Figure 8.5 land surface topography, Athabasca oil sands area



From Rakhit Petroleum Consulting Ltd., 1999

Figure 8.6 Wabiskaw/McMurray zone potentiometric Surface map, Athabasca oil sands area.

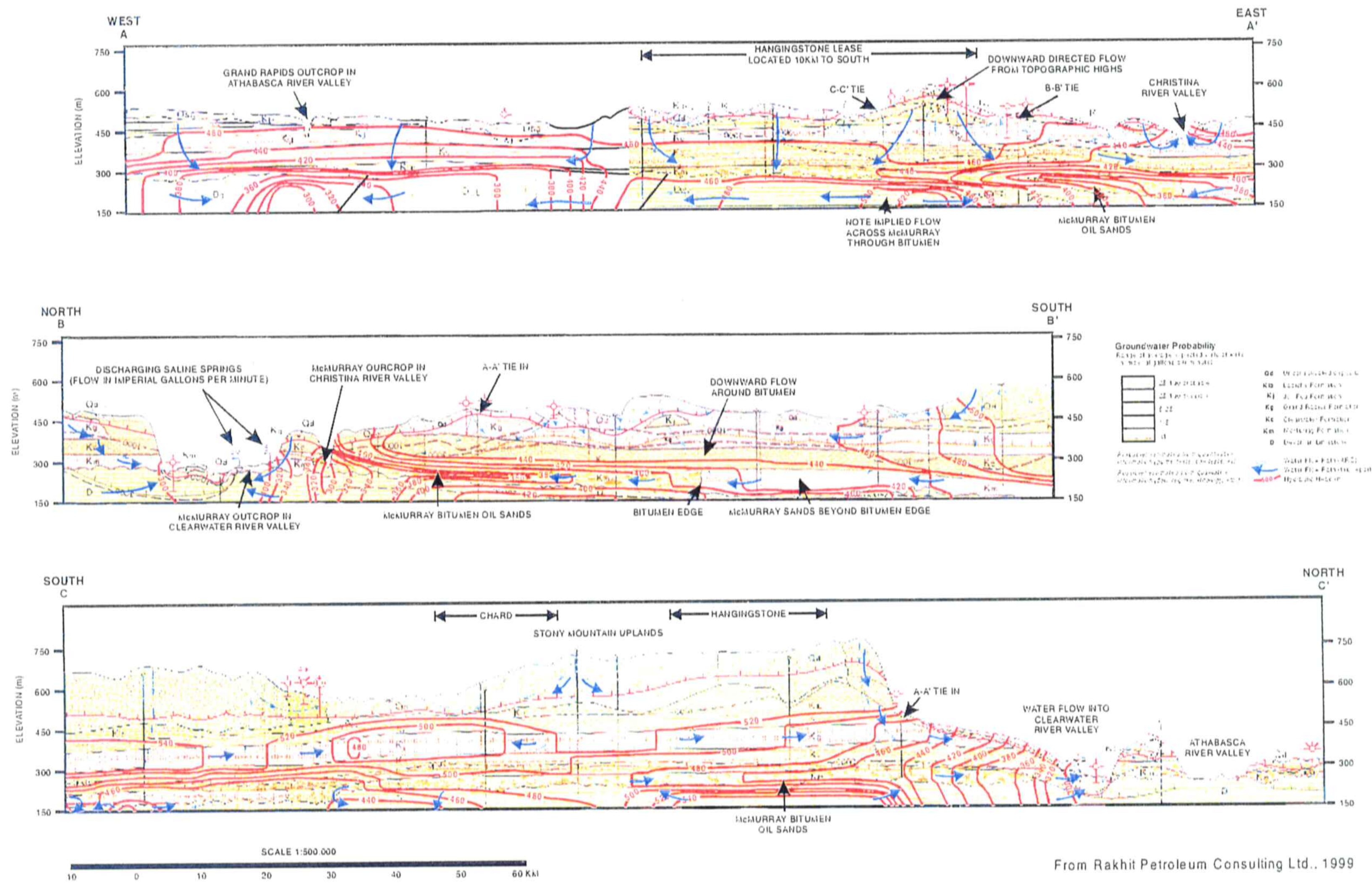
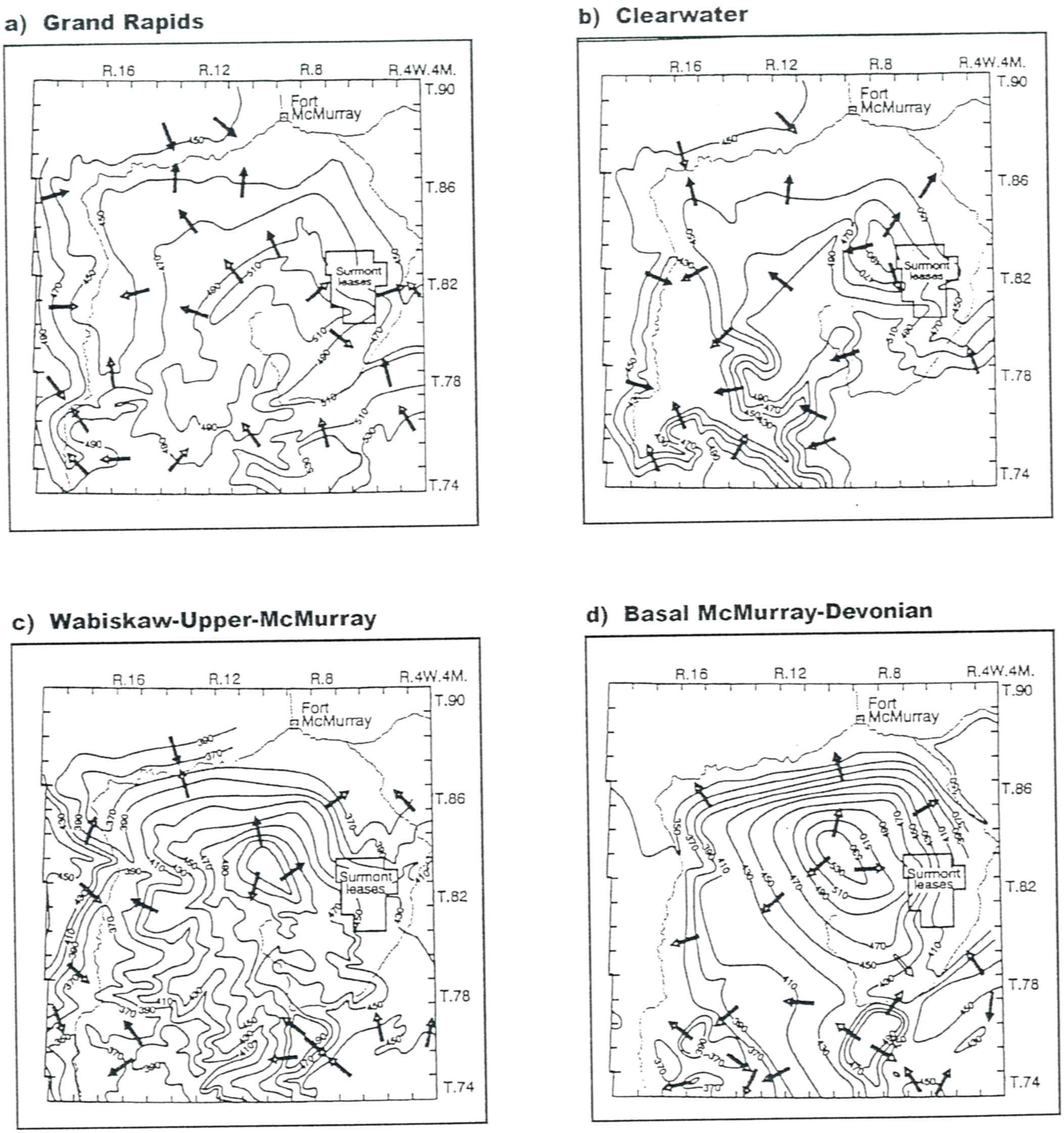
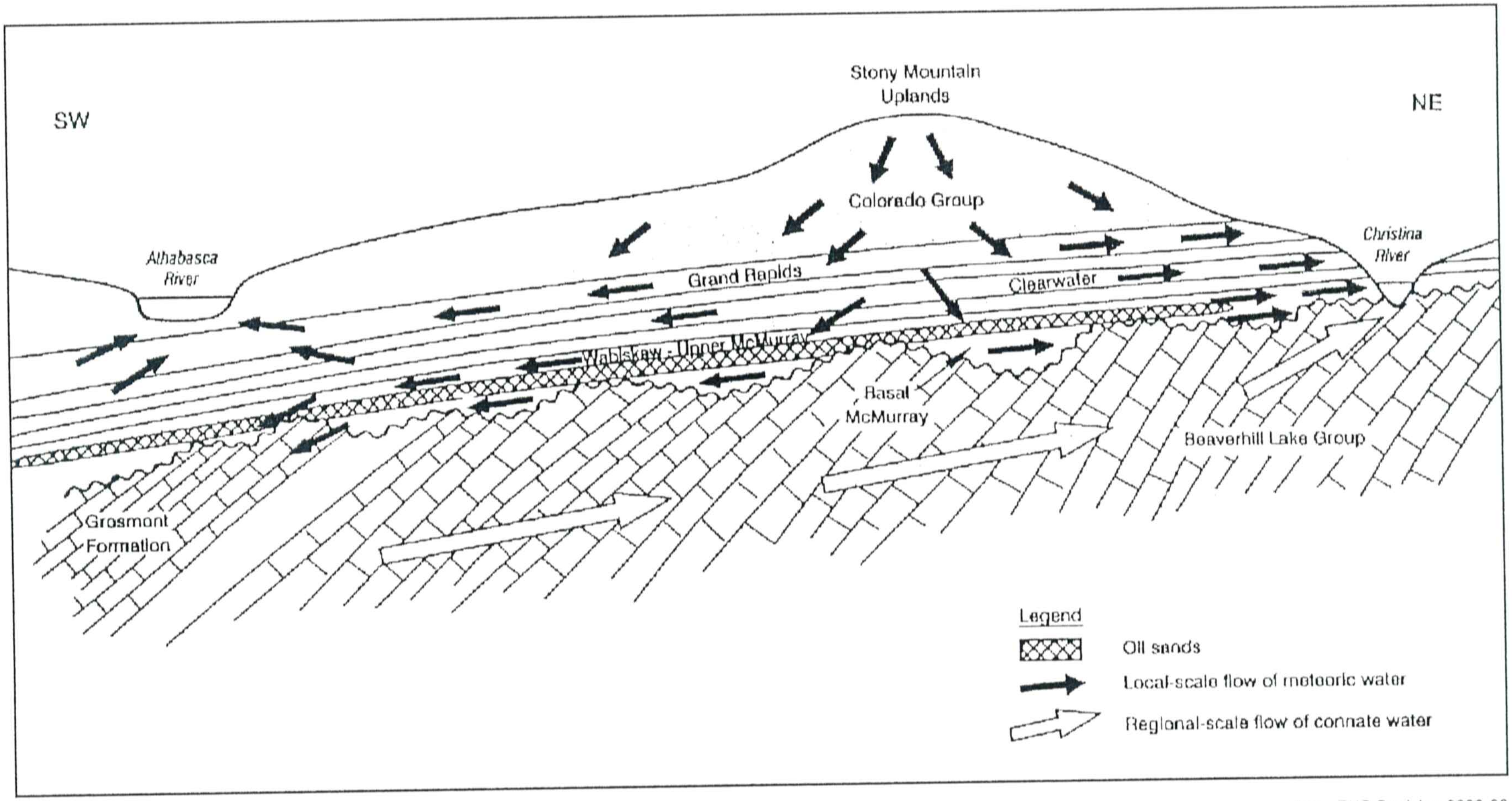


Figure 8.7 Hydrogeologic cross-sections, Athabasca oil sands area



From EUB Decision 2000-22

Figure 8.8 Hydraulic head distribution Athabasca area aquifers



From EUB Decision 2000-22

Figure 8.9 Diagrammatic representation of the flow of formation water in Athabasca area aquifers along a dip cross-section

At this point we encounter the proximity of a lateral ramp extension of the Brazeau sheet as it turns westward into the McConnel Thust (Fig.9.1).

The associated head values driving the Turner Valley at Burnt Timber to the south of us occur between 815-825.0 m hydraulic head not to different from the head values determined across the eastern plains at Turner Valley level. Two gas columns are defined and driven by separate aquifers (Fig. 9.2). East of the Burnt Timber thrust, regional head values are determined, with a flow pattern along an east to northeast direction. West of this complex a rapid change in energy is observed where the flow parameters appear to be contained by the McConnel thrust to the west and also influenced by the Brazeau sheet to the north.

Along the McConnel thrust is the Wildhorse Creek Pools. This sheet is drive by high hydraulic head and run parallel to the thrust sheet.

From this point northward we start to encounter the third play type. That of Devonian reefs productive in the Wabamun Nisku and Leduc sections.

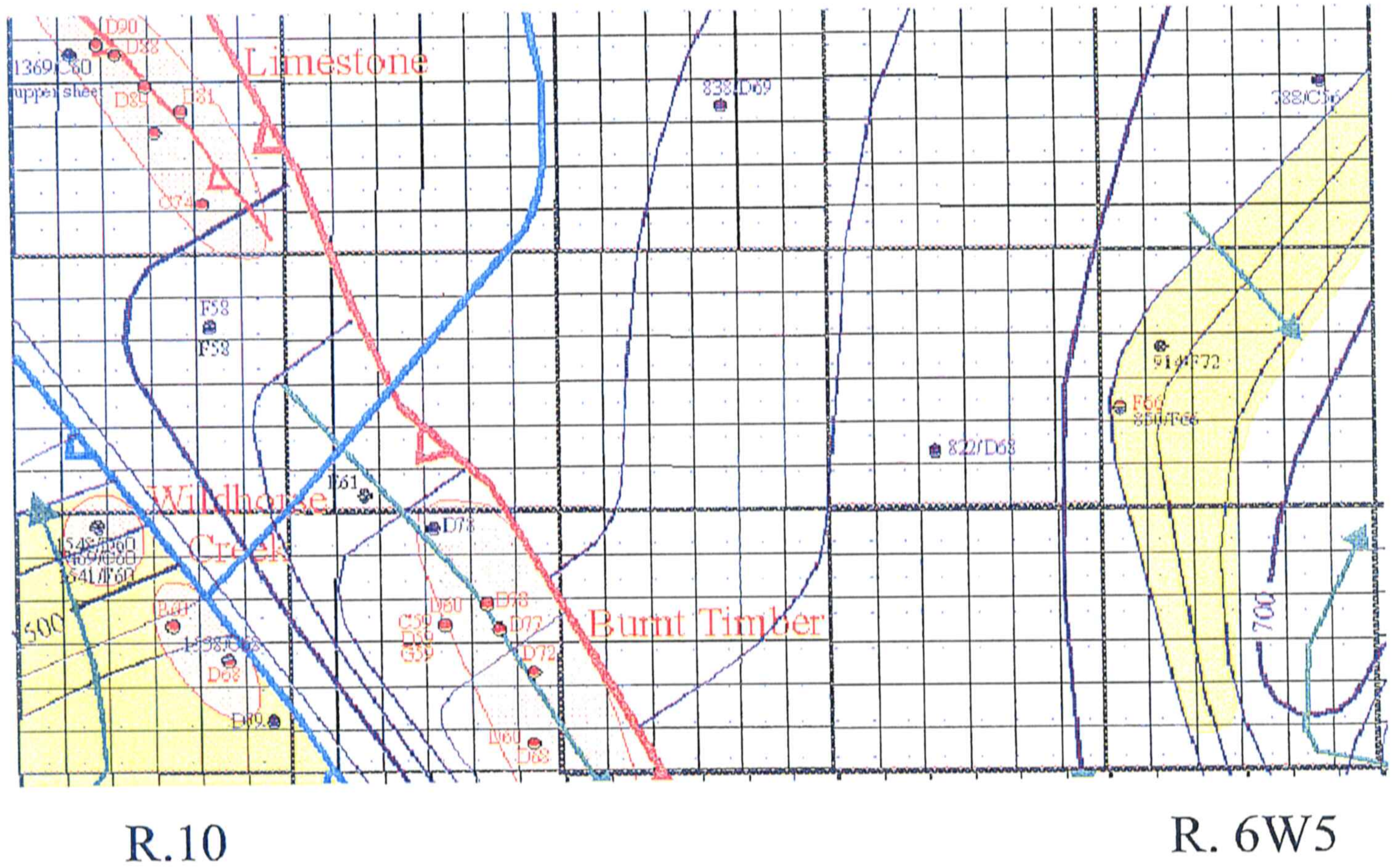


Figure 9.1 Lateral ramp of the Brazeau sheet head differential across the McConnel thrust sheet.

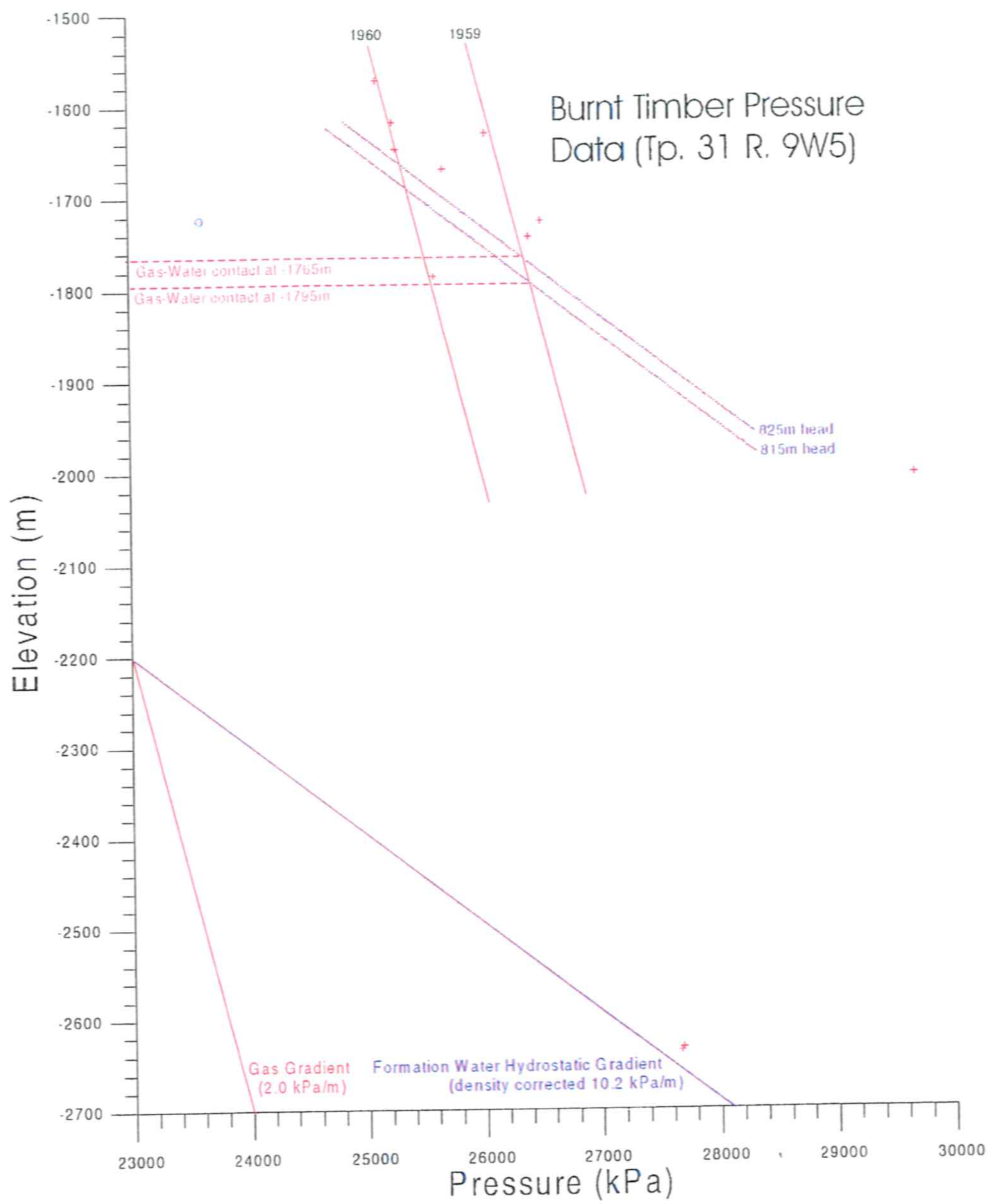


Figure 9.2 P/E plot separate sheets = separate head differentials=different gas water contacts

Looking northwest to Limestone Mountain from here, we are standing on the Brazeau sheet with hydrocarbon reservoirs occurring in both Mississippian and Devonian strata. Here the head differential between vertical sections becomes very appareant. On the pressure versus elevation graph and head map (Figs. 10.1, 10.2).

Several gas columns are defined at Limestone each pool with a determinable gas water contact defined by the offsetting head potential. Of significant importance is the apparent vertical discontiniuty determined here as the platform system plunges under the thrust sheets yet the head values clearly define the amplitude of vertical separation.

The upper and middle sheets of the Turner Valley have clearly definable gas water contacts and separate gas columns as defined by the pressure versus elevation graph (Fig. 10.3). Upon looking at e pressure profile for the total strat section here, (Fig. 10.4) on the pressure versus elevation indicates vertical and lateral discontiniuty. Formation waters in this region vary from fresh water 16000 mg/l Upper Nisku to 80 mg/l Devonian deep.

When looking and the Devonian section across the foothills region several parallels become apparent as in the Mississippian strata. The further West one goes into the disturbed belt the higher the energy potential as defined by (Figs. 10.5, 10.6, 10.7) Each gas column is driven by an aquifer system with decreasing energy potential as one approaches the un-deformed section.

CONCLUSIONS

Formation water flow systems can be broken down into three main zones. The zone west of the McConnel thrust is characterized by high head values ranging from 1200 - 1600.0m with high salinity. This suggests poor hydraulic communication between the zone to the east and definitive vertical separation

The central zones or most easterly developed thrust sheets are characterized by lower energy potential, heads ranging from to 800.0-1000.0m with salinity in the more intermediate renge from 70 000 - 100 00o mg/l.

The un-deformed strata is characterized by heads ranging from 700 - 900.0 m with salinity Ranging from 50 000 - 80 000 mg/l. This zones main feature is a trough of low hydraulic head extending southward from the northern regions including Wildcat Hills, Jumping Pound and the lower platform at Limestone.

Formation water flow systems within the foothills are generally directed parallel to structural strike.

SUPPORT; Andrew Newson provided figs for play types and traps.

MOOSE OILS LTD.

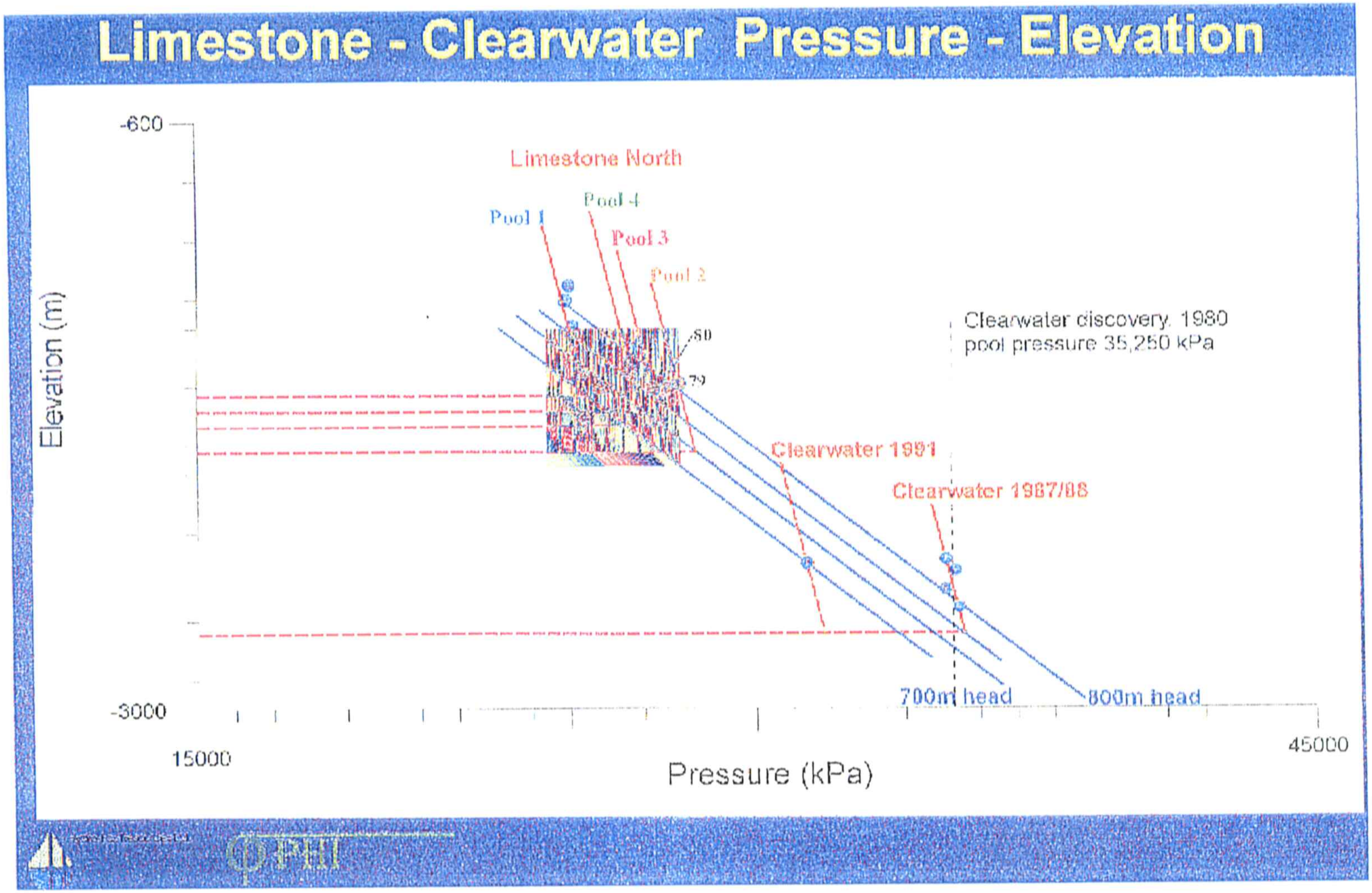

Limestone - Clearwater Pressure - Elevation
-600
-3000
Elevation (m)
Limestone North
Pool 1
Pool 4
Pool 3
Pool 2
80
79
Clearwater discovery 1980
pool pressure 35,250 kPa
Clearwater 1991
Clearwater 1987/88
700m head
800m head
15000
45000
Pressure (kPa)
PHI

Figure 10.1

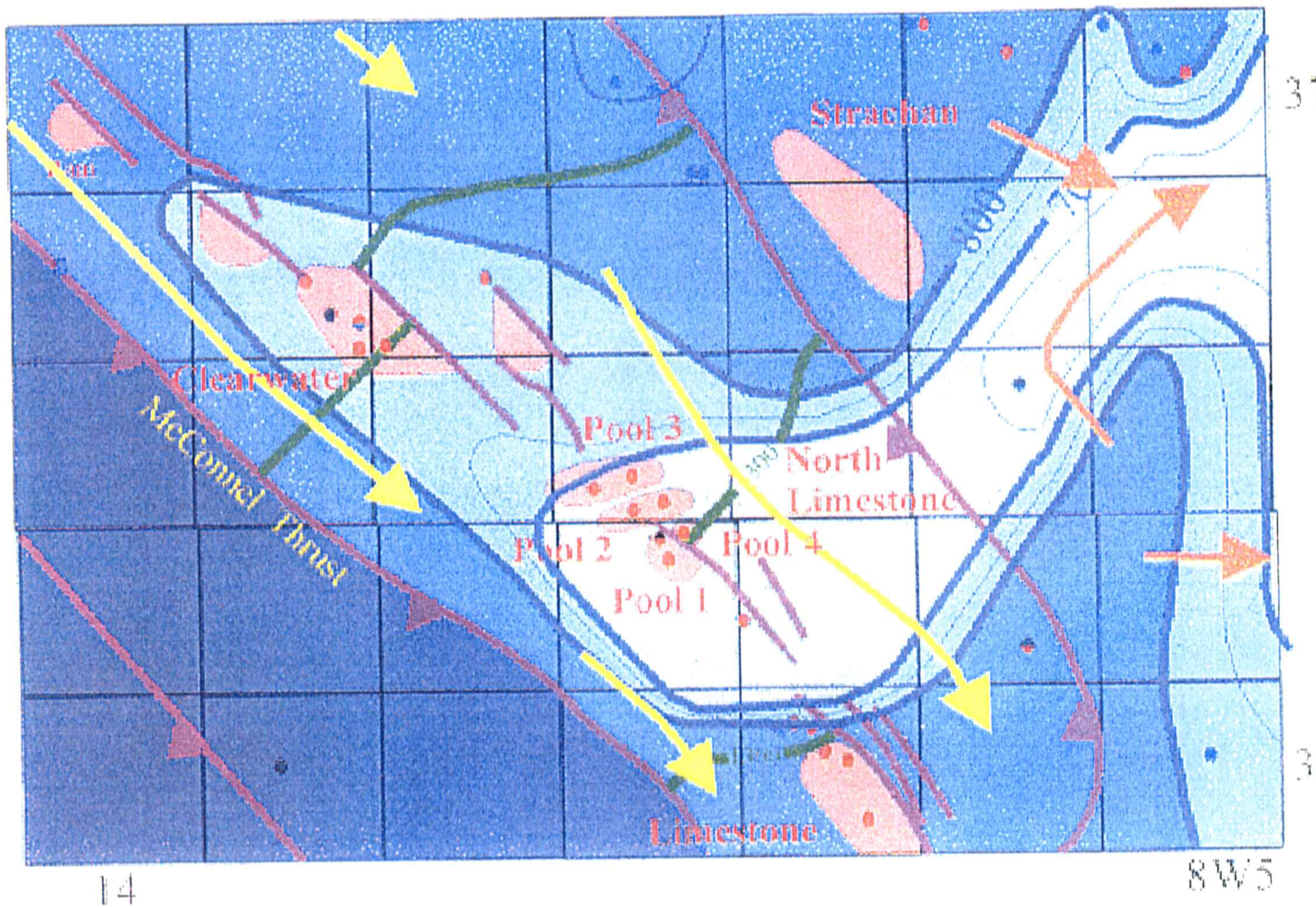
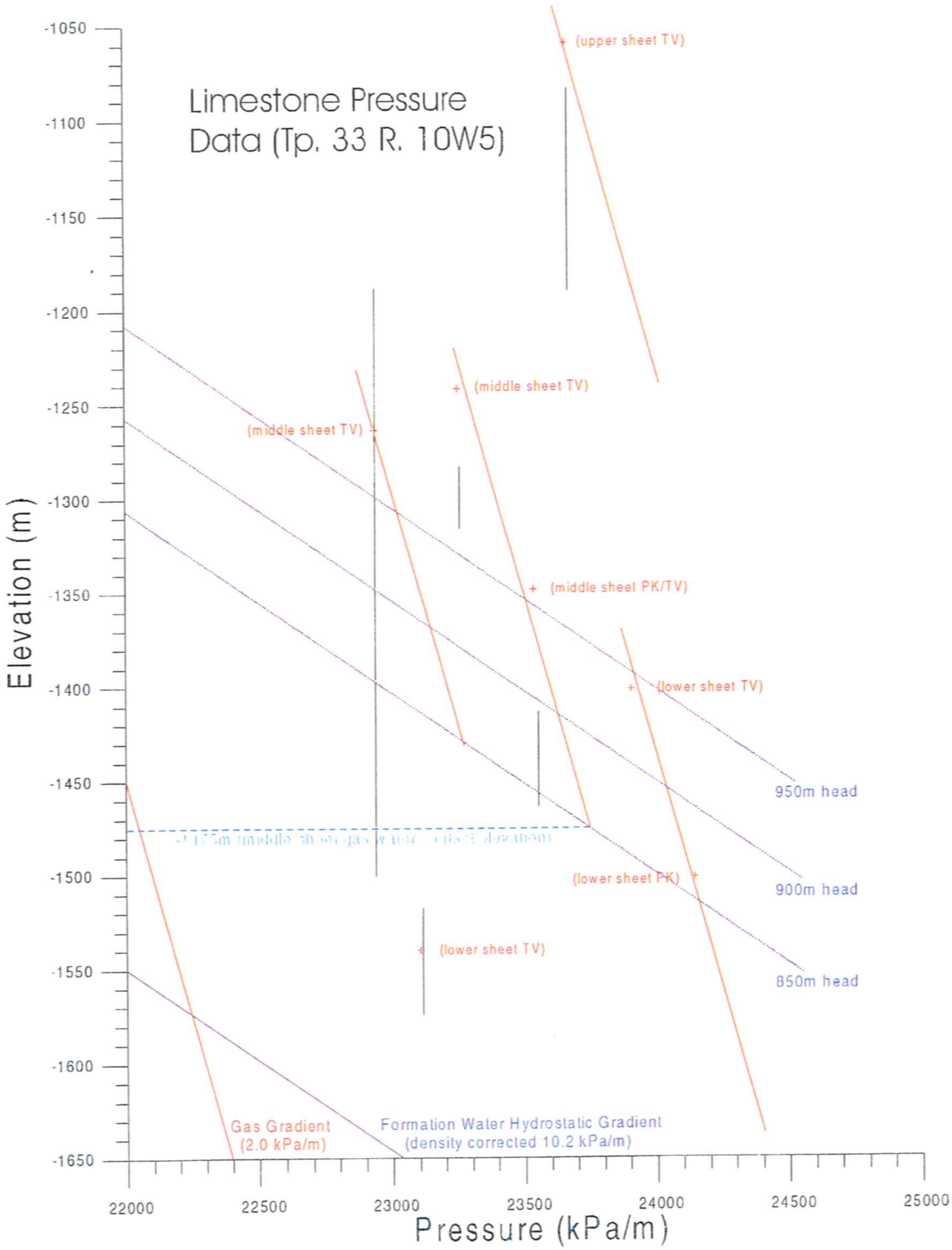


Figure 10.2 Clearwater-Limestone hydraulic head: Note lower platform aquifer system plunges under Brazeau sheet. Vertical separation flow patterns confined by thrust sheets.



Limestone Pressure
Data (Tp. 33 R. 10W5)
(upper sheet TV)
(middle sheet TV)
(middle sheet TV)
(middle sheet PK/TV)
(lower sheet TV)
(lower sheet PK)
(lower sheet TV)
950m head
900m head
850m head
Gas Gradient
(2.0 kPa/m)
Formation Water Hydrostatic Gradient
(density corrected 10.2 kPa/m)
Elevation (m)
-1050
-1100
-1150
-1200
-1250
-1300
-1350
-1400
-1450
-1500
-1550
-1600
-1650
22000
22500
23000
23500
24000
24500
25000
Pressure (kPa/m)

Figure 10.3

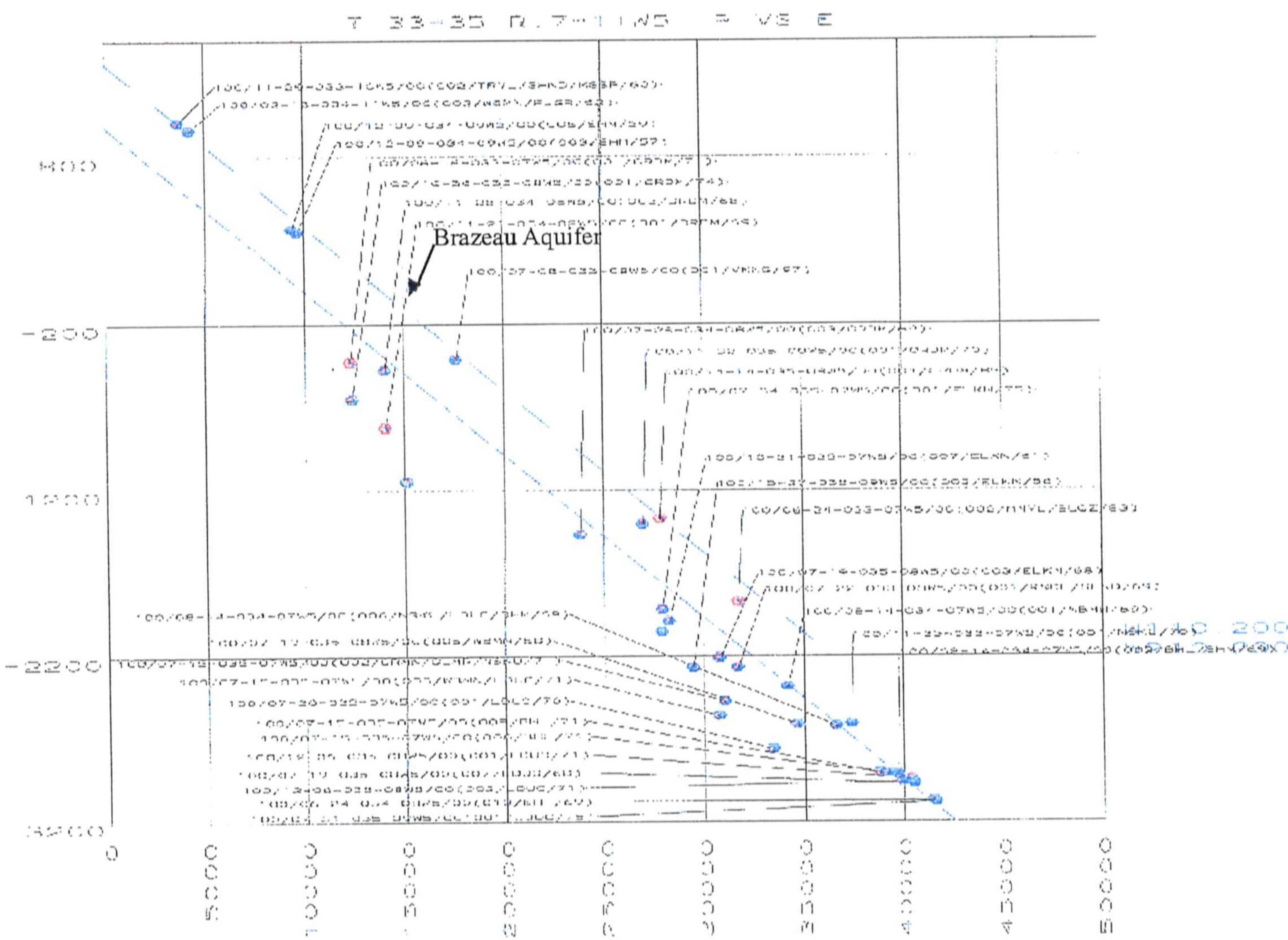
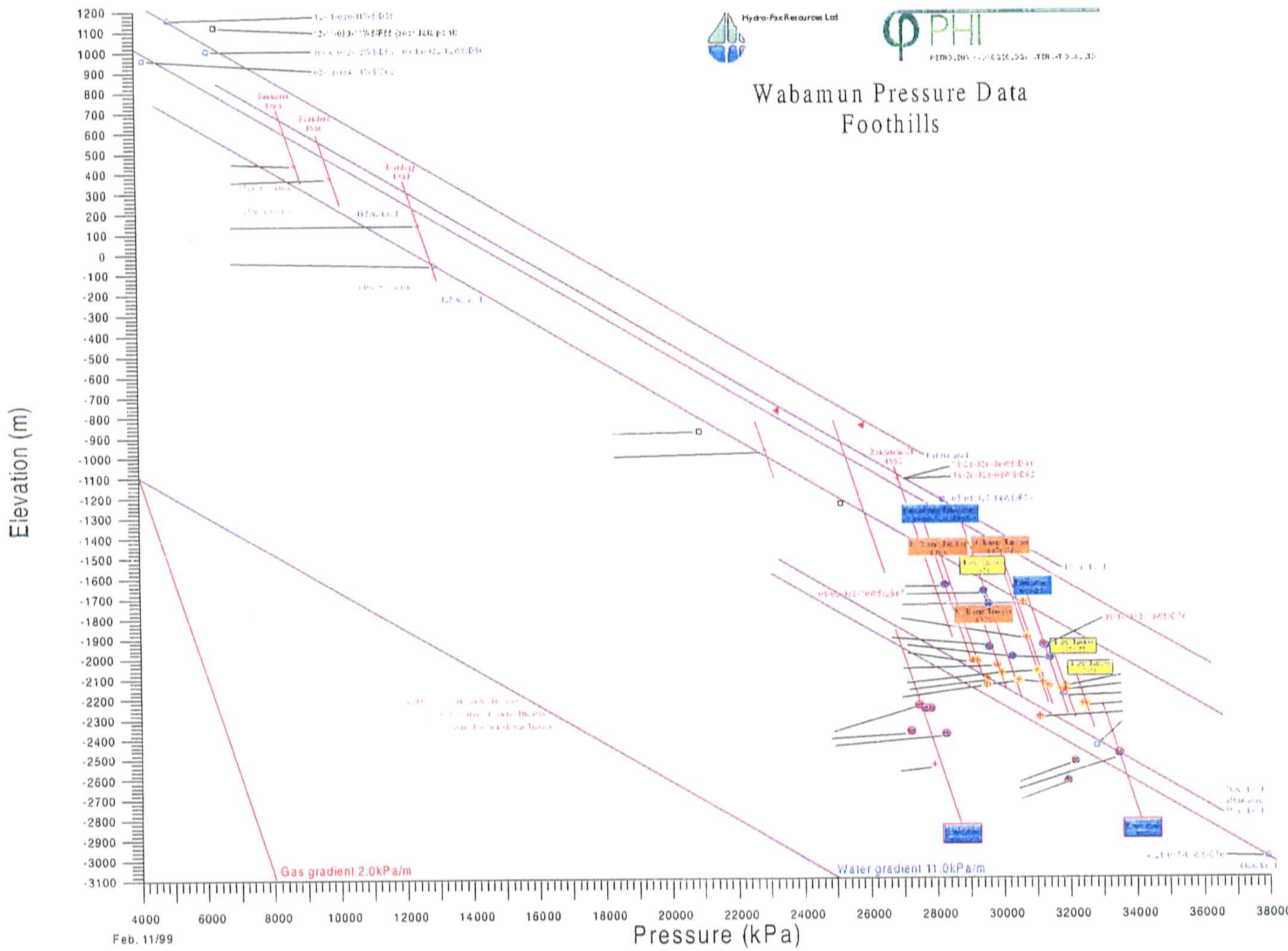
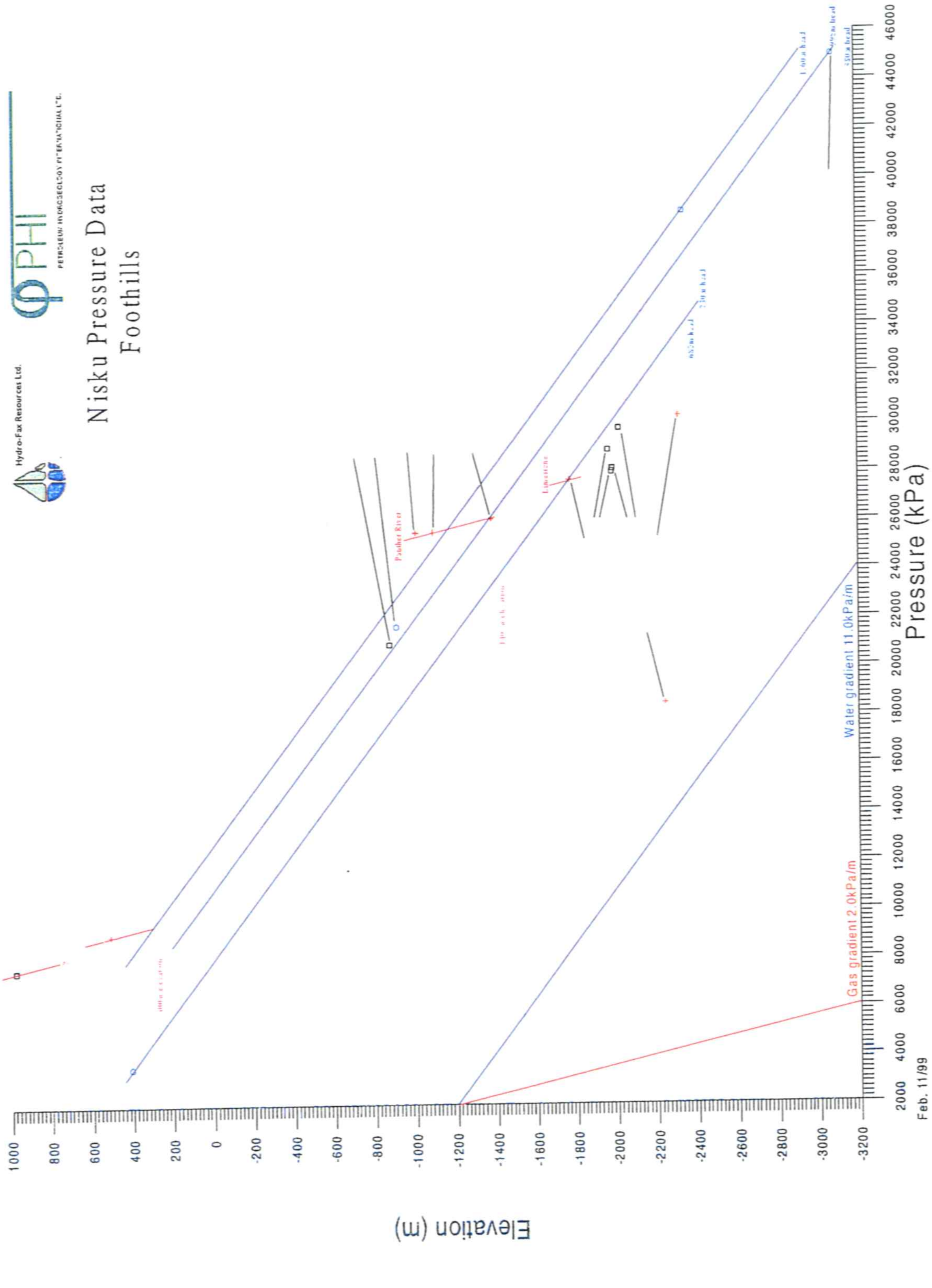


Figure 10.4 Total permeable strat column first encounter with oil, Cardium - Devonian



Hydro-Fax Resources Ltd
PHI
Wabamun Pressure Data
Foothills
Elevation (m)
Pressure (kPa)
Gas gradient 2.0kPa/m
Water gradient 11.0kPa/m
Feb. 11/99

Figure 10.5



Hydro-Fax Resources Ltd.
PHI
Nisku Pressure Data
Foothills
Water gradient 11.0kPa/m
Gas gradient 2.0kPa/m
Panther River
Limestone
Pressure (kPa)
Elevation (m)
Feb. 11/99

Figure 10.6

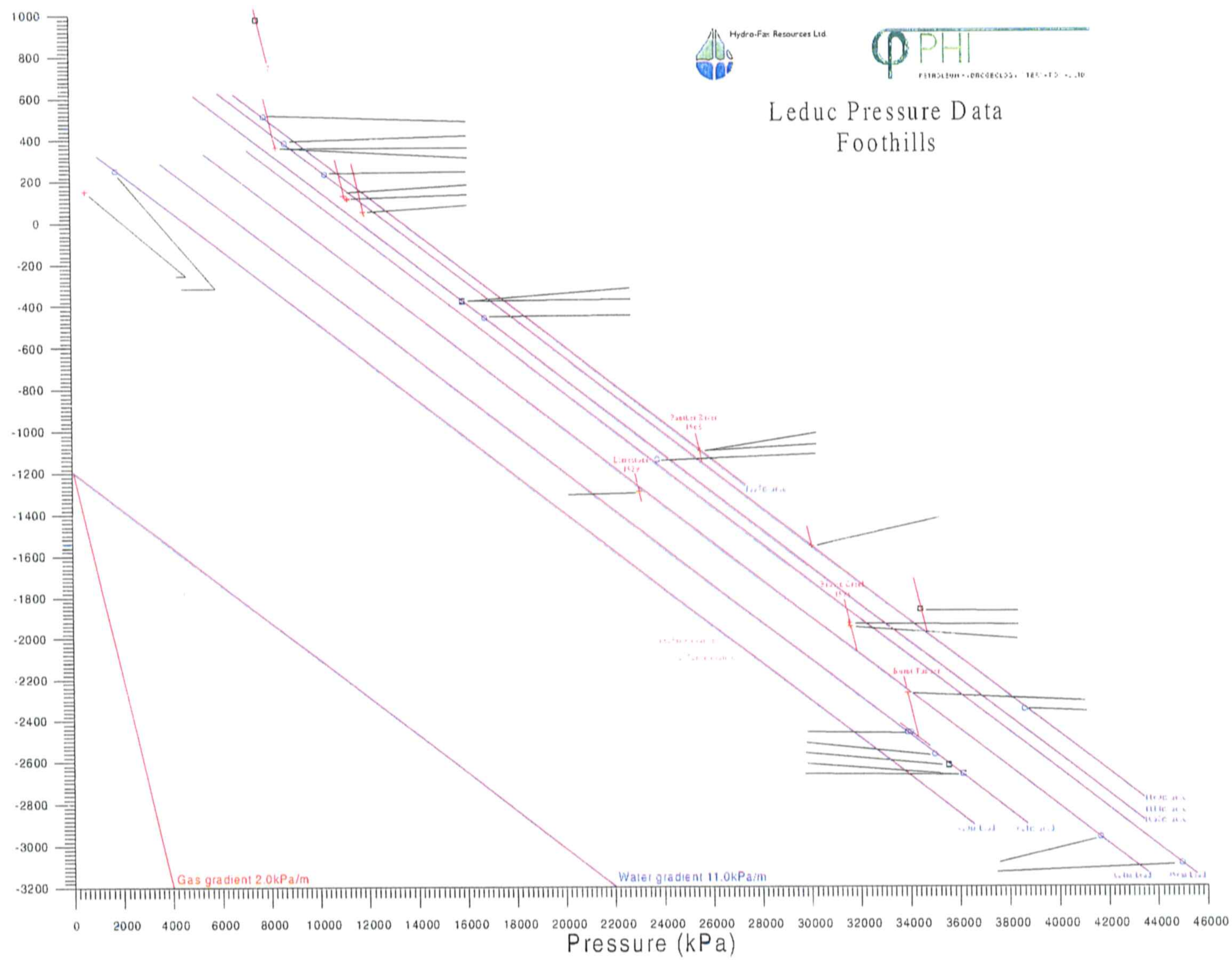

Leduc Pressure Data
Foothills
Hydro-Fax Resources Ltd
PHI
Elevation (m)
Pressure (kPa)
Gas gradient 2.0kPa/m
Water gradient 11.0kPa/m
1000
800
600
400
200
0
-200
-400
-600
-800
-1000
-1200
-1400
-1600
-1800
-2000
-2200
-2400
-2600
-2800
-3000
-3200
0
2000
4000
6000
8000
10000
12000
14000
16000
18000
20000
22000
24000
26000
28000
30000
32000
34000
36000
38000
40000
42000
44000
46000

Figure 10.7

Notes written by Kevin Parks for the 1996 HydroDiv Field Trip "Prairie Hydrogeology for the Petroleum Geologist"

Groundwater flow systems exist within a complex spatial and temporal hierarchy of scales. That is to say, groundwater motion is simultaneously affected by the physics of flow from the scale of an individual pore to the scale of an entire basin and by geomechanical and hydrologic forcings that take place over the course of a day to over millions of years. The hydrogeologist's task is to unravel this complexity in natural systems. The flow systems feeding the Raven springs are a good example of how scale and hierarchy affect groundwater study.

The study of scale effects in groundwater systems is a difficult and challenging discipline of hydrogeology. It gets particularly complicated at the mathematical level where numerical models, stochastic equations, geostatistics and fractal mathematics are the order of the day. Nevertheless, the study of scale effects is essential because conceptual models of hierarchy can: 1) help evaluate and integrate data from disparate sources; and 2) help fill-in data gaps. These activities in turn increase the predictive power of hydrogeologic study for contaminant clean-up, reservoir characterization and petroleum hydrogeology.

The shallow groundwater flow system that feeds the freshwater springs at the Raven Trout Brooding Station near Crammond, Alberta, is a good example of how complex hydrogeologic processes act over multiple scales of space and time.

Hierarchy in Groundwater Flow Systems

1. Flow System Hierarchy

Engelen and Jones (1986) define a groundwater flow system as " a complex, four-dimensional cohesive system with quantity and quality aspects in a non-homogeneous, anisotropic medium. It changes flow patterns and chemical character in time under variable natural and artificial stresses." They go on to add: "Regional studies indicate that the aquifer should no longer be considered as the basic unit in our thinking because it is often used (i.e., spatially occupied) by a number of groundwater systems. Each of them may use only part of the aquifer, has free or fixed boundaries with adjacent systems and extends with its recharge and discharge parts outside the aquifer. In fact the system instead of the aquifer is the functional unit and it has its own identity as a coherent unit of groundwater and earth materials in space and time".

Hierarchy in a system implies that differentiation of form or process can be made when measurement is applied across continuous scales or across thresholds of discrete scales. Measurement or observation at a single scale may not reveal hierarchy, rather it is observation across multiple scales that allows identification of hierarchy.

Tóth (1963) introduced the notion of hierarchy in hydrogeology. In homogeneous, hydraulically continuous drainage basins with complex water table topography, gravity-driven flow systems will evolve and occupy the entire basin volume. Small-scale, local systems will join recharge areas to adjoining discharge areas. Basin drainage divides will be linked to the draining trunk streams by large-scale regional systems. Intermediate systems link non-adjacent recharge and discharge areas at spatial scales that fall between regional and local systems (Fig. 1). Note that recharge areas may simultaneously replenish flow systems of multiple scales, and discharge areas may be simultaneously linked to local, intermediate and regional systems. Even in the absence of geologic heterogeneity, spatial and temporal variations in precipitation, evaporation and surface drainage rates would cause the flow system geometry to vary from the ideal.

2. Temporal Hierarchy

The time needed for a hydrogeologic system to adjust to a new steady state after a change in boundary conditions (geo-mechanical and hydrologic forcings) can be characterised by a factor called the "system time-constant", $T*$:

$$T* = \frac{S_s L^2}{K}$$

Where S_s is specific storage, K is hydraulic conductivity and L is a characteristic length of the system under observation.

Essentially $T*$ encapsulates how quickly a hydrogeologic system can adapt to new boundary conditions by release and transmittal of fluids. If you are observing a system to which there has been a significant change at a time before present that is less than $T*$, and if your scale of observation L is large enough, you should see the transient readjustment effect. If you observe the system some time greater than $T*$ after the disturbance, or if your scale of observation L is small, then the system will appear to be in steady state.

Multiple disturbances to a flow system at different time scales can be superimposed on one another. This creates a "memory effect" – that is, a flow system may be out of equilibrium with modern boundary conditions because it may still contain in part the decaying effects of previous disturbances. These superimposed time-effects evident across different spatial scales again contribute to hierarchy.

3. Spatial Hierarchy and Geologic Heterogeneity

Rock-framework heterogeneity further complicates the spatial geometry of the flow system hierarchy. Over the past two decades, reservoir geologists and hydrogeologists have recognised that rock heterogeneity also occurs in a cascading hierarchy of scales, each impacting flow-system geometry in a particular way.

Some workers have classified the hierarchy of scale of heterogeneity as a range of classes from microscale hereogeneity (pore scale variations) to megascale (tectonic elements of a basin). As one rises in the hierarchy of spatial scales, the contributions of smaller scale heteogeneities to flow behavior average together in a complex fashion to impact flow behavior at higher scales.

Munderstand how measurements of permeability made at the scale of a core plug or a well test relate to the properties of rock at the interwell to reservoir scales. Regional hydrogeologists face a more difficult task – relating those same measurements to flow properties of rock at the formation to basin scale.

The Hydrogeology of the Raven Springs

The Raven Springs are located at the Raven Trout Brooding Station (Province of Alberta) near Caroline. The trout-brooding station obtains its water supply from the springs. The springs are located behind the brooding station part way up the bluff of the valley of Beaver Creek, a minor tributary of the Raven River to the north. They issue from sub-horizontal contact between the sands that make up the bluff and the underlying sandstone bedrock. The springs are characterised by high but variable flow rates ranging from 9,000 to 18,000 l/min. Highest flow rates are reported in the spring months. One historical maximum was reported in June 1970, one week following an intensive three-day storm event. This relationship supports a strong hydrologic connection with surface processes.

1. Groundwater Chemistry

In 1994, the water pH was measured to be 7.4 at the old spring house. The temperature reportedly varies from 5.4 to 2.2° C, with the coldest temperatures occurring in the winter. A water sample collected from the old spring house in June 1996 had the following chemical composition:

Property	Spring Water	Chemical Constituent	Spring Water mg/l
Specific Gravity	1.006	Sodium	5.8
pH	7.43	Potassium	2.05
Electrical Conductivity	555 uS/cm	Calcium	77.2
Turbidity	0.24 NTU	Magnesium	25.6
		Sulphate	4.5
		Chloride	7.4
		Bicarbonate	361
		Hardness	298
		Iron	<0.04
		Manganese	<0.003
		Flouride	0.14
		Nitrate and Nitrite	1.14
		Alkalinity	296
		Total Dissolved Solids	483

By comparison with most prairie groundwaters the Raven Springs are of a very high quality. The water is calcium-bicarbonate type. The dominance of bicarbonate is indicative of meteoric recharge. Sulphates are very low (4.5 mg/l!) for Alberta, indicating that the discharging groundwaters do not pass through sulphur-bearing clay tills.

The calculated hardness reflects the predominance of calcium and magnesium over sodium cations. Anywhere else in the world this would be considered to be very hard. But in comparison with other shallow groundwaters and surface waters of the Alberta prairies, this hardness is about normal. The presence of measurable nitrates is usually an indicator of non-point source pollution – possibly from animal waste or septic fields.

Around the springs are numerous tufa terraces. Tufa is micorcrystalline calcite. Tufa deposits are common at cold springs in Alberta. As infiltrating surface waters penetrate the vadose zone (between the ground surface and the water table), the partial pressure of soil vapour CO_2 (from decaying vegetation etc.) increases. This causes the water pH to drop and the solubility of calcite to increase. When groundwater discharges, CO_2 is lost to the atmosphere, and the solubility of calcite decreases causing precipitation of tufa. Interestingly the bluff above the springs is composed of uncemented, well-sorted, red-orange iron stained quartz sands. This contradiction is explained below.

2. Flow System Geometry and Hierarchy

At first glance, the Raven Springs appear to be a simple contact spring – water infiltrating the sands of the bluff flow along the top of the bedrock and discharge along the valley of Beaver Creek. That the highly variable flow rates are linked to weather and seasons, the water chemistry is fresh and nitrates are present in measurable amounts, suggest a very local flow system. This is probably 90 per cent true. However, consideration of the regional hydrogeology and the presence of the tufa deposits suggest that more than one scale of flow system is present here.

Figure 2 shows the local topography. The surrounding hills to the south are hummocky glacial moraine composed mainly of poorly sorted clay tills. Surface drainage is poor, giving rise to raised bogs and patches of black spruce. Immediately south of the springs, however, there is a large, flat depression underlain by the well-sorted fine-grained sand which makes up the bluff. Drainage here is good, giving rise to aspen parkland vegetation and abundant farms. This sand has been interpreted as a glaciofluvial or galciolacustrine deposit. Bedrock elevation mapping of the area suggests that there are glacial channels carved in the bedrock surface below the sand. Figure 3 shows the regional flow path inferred from the topographic map.

The bedrock underlying this area is the Tertiary Paskapoo Formation. It is comprised of continental clastics (sandstones, mudstones etc.) which, significantly are often calcite cemented. The Paskapoo strata are weathered, jointed and fractured in outcrop and in subcrop below the Quaternary drift. On a regional scale the water table in the bedrock slopes downwards towards the Raven River, north of the trout brooding station. Flowing water wells and seismic drill holes are reported in the Raven River valley, indicative of upward discharge of groundwater.

These pieces of information can be interpreted within a hierarchical arrangement of flow and geology, to better understand the springs (Figure 4). At the largest scale, there is a regional flow system that links recharge in the till-mantled uplands to the Raven River. This flow system probably occupies the bedrock layers. This flow system discharges along the course of the Raven River.

At the next scale down, we see a local flow system that delivers infiltrating water from the sand deposit above the bluff, to the springs along Beaver Creek and as baseflow to the creek.

The local flow system in the sands may them be subdivided into smaller systems because of geologic heterogeneity. Any channels carved into the bedrock are probably the thalwegs (deepest channels) of ancient stream courses. These could act to focus flow into the spring localities.

As mentioned above, the presence of tufa seems to contradict the mineralogy of the sands. Unless there is an unrecognised source of calcium carbonate (as mineral grains?) within the sand, there must be a component of discharge to the springs coming from the regional flow system, which passes through the calcite-cemented Paskapoo Formation. This contribution is entirely consistent with our concept of hierarchy.

It is also speculated that the regional discharge from the bedrock is being focussed by fractures. Such a fracture pattern may be further interlinked with the flow in the sand deposit, as the thalwegs of the ancient streams would have most likely preferentially eroded heavily fractured zones in the bedrock. Again this is evidence of hierarchy in flow and in geologic heterogeneity.

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Acknowledgements:

Over the past decades, several reports have been prepared for the Trout Brooding Station by professional staff of Alberta Environment and the Alberta Research Council, among others. Some of the material in this field note came from these unpublished reports plus the personal recollections of Dr. Jozsef Toth. Steve Cunningham and Rod Burnes, the AE staff at Raven and Jim Wagner with the AE in Edmonton are thanked for providing copies of numerous reports, memo's and water analyses.

The Redwater oil field is one of a number along the Rimbey-Meadowbrook Reef Trend (Fig. 12.1) with reservoirs within the Upper Devonian Leduc Formation. This is a southwest-northeast linear trend of reefs that extends about 320 km across central Alberta. The Rimbey-Meadowbrook Reef Trend has produced hydrocarbons since 1947 when the Leduc discovery initiated the modern oil and gas industry in Alberta. Leduc reefs along the Rimbey-Meadowbrook Reef Trend have been estimated to contain 576 x $10^6 m^3$ of oil in place (Podruski et al., 1988) and 209,536 x $10^6 m^3$ of gas (Reinson et al., 1993). A smaller amount of oil is also found in overlying Nisku reefs, in particular at Leduc-Woodbend. The source rock for these hydrocarbons is the Duvernay Formation (Stoakes and Creaney; 1984, Li et al., 1998). Redwater, discovered in 1948, is the largest of the Leduc fields along the Rimbey-Meadowbrook Trend and the second largest Devonian pool in Alberta. The Leduc reef at Redwater occurs approximately 24 km east of the western margin of the Cooking Lake Platform (Fig. 12.1), in apparent platform-interior position (Wendte, 1992). The reef has a triangular shape, a thickness of approximately 300 m and a total areal extent of close to 600 km^2. The oilfield occurs in the upper updip northeastern periphery of the reef (Chow et al., 1995). Its original oil in-place reserves (OIP) have been estimated to have been 207 x $10^6 m^3$, of which 128 x $10^6 m^3$ are producible and 126.2 x$10^6 m^3$ have been produced (Switzer et al., 1994). Along the northeastern reefal periphery, a basal embayment extends into the reef complex allowing for intertonguing of Leduc and Duvernay facies (Chow et al., 1995). The Duvernay Formation here is organic-rich and immature (Stoakes and Creaney, 1984; Chow et al., 1995).

The reservoirs and source rocks of the Rimbey-Meadowbrook Reef Trend fields are Late Devonian (Frasnian) aged rocks of the Woodbend Group. The Woodbend Group consists of a thick sequence of shallow water platform carbonates (Cooking Lake Platform) on which grew numerous platform margin reef build-ups (Leduc Formation) (Fig. 12.2), capped by basin-filling shales and limestones (Ireton and Duvernay formations). The Cooking Lake Platform is generally limestone but along the central core of the Rimbey-Meadowbrook Trend, it and the overlying Leduc Formation consist of crystalline dolomite. The reefs at Redwater and Golden Spike, which are located off the principal reef trend, are undolomotized and consist mainly of limestone. Each of the biohermal buildups are connected to some degree to the underlying Cooking Lake Platform aquifer.

Hydrocarbon Migration along the Rimbey-Meadowbrook Reef Trend

Gussow (1954) proposed his "differential entrapment" model, (also known as spill-point theory) using the distribution of oil and gas in the Leduc reefs along the Rimbey-Meadowbrook Trend as one of his principal examples. Along the reef trend, gas is generally present in the more down-dip reservoirs while oil occurs up-dip with most of the reservoirs being filled to their spill points (Fig.12.2). Gussow (1954) envisaged long distance migration of oil and gas driven by buoyant forces along a definite pathway ("river of oil"). Hydrocarbons enter the reef system at the down-dip end and proceed to fill the first trap. When the spill point of this trap is reached, hydrocarbons are "spilled" in to the next trap and so on. Further burial of the source rock would have led to generation of gas which in turn entered the system and displaced oil to spill point, eventually filling the downdip reservoirs with gas. Therefore, from deepest (downdip) to shallowest (updip) reservoirs along the reef trend, one would expect to find traps full of gas, then

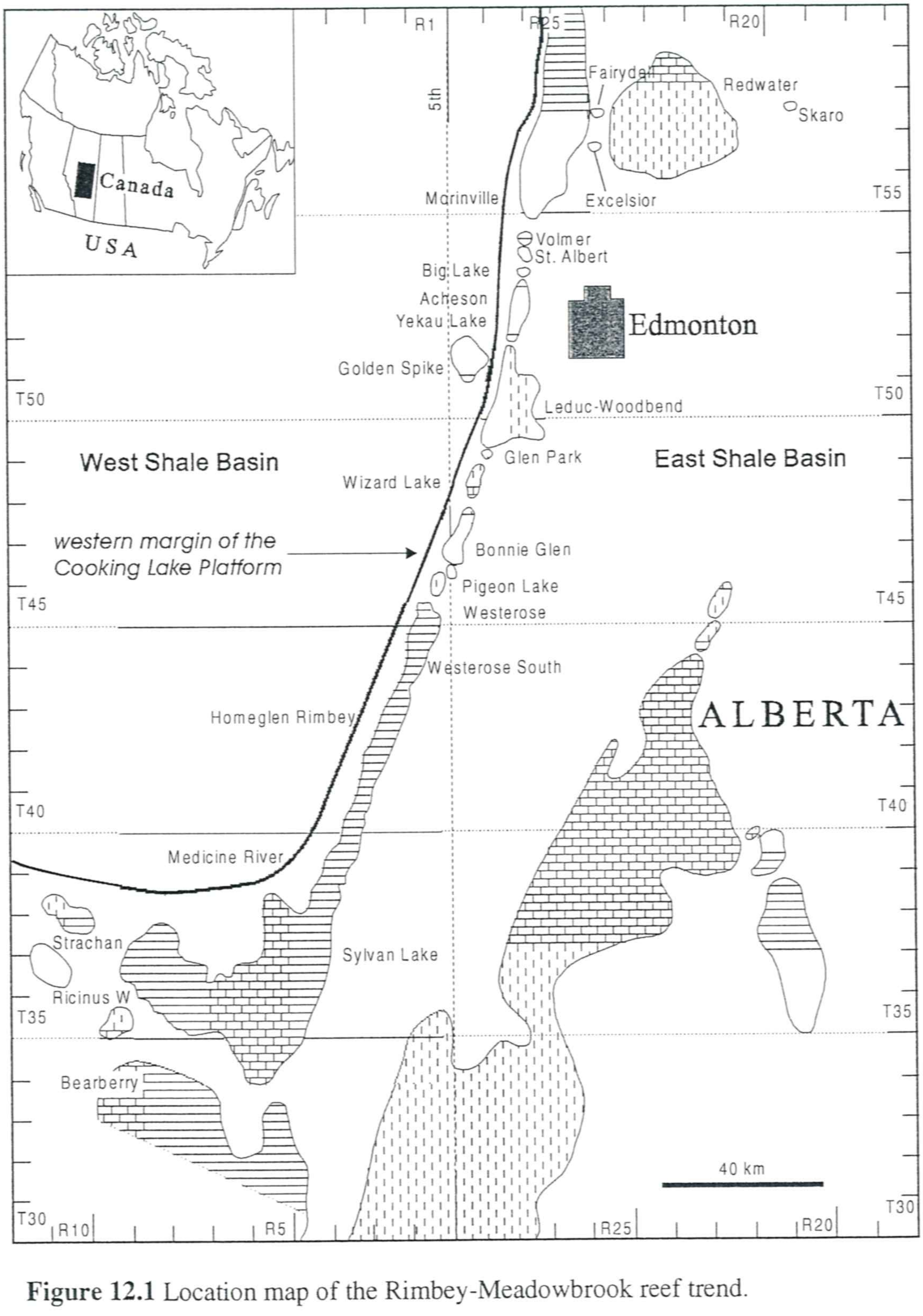

Figure 12.1 Location map of the Rimbey-Meadowbrook reef trend.

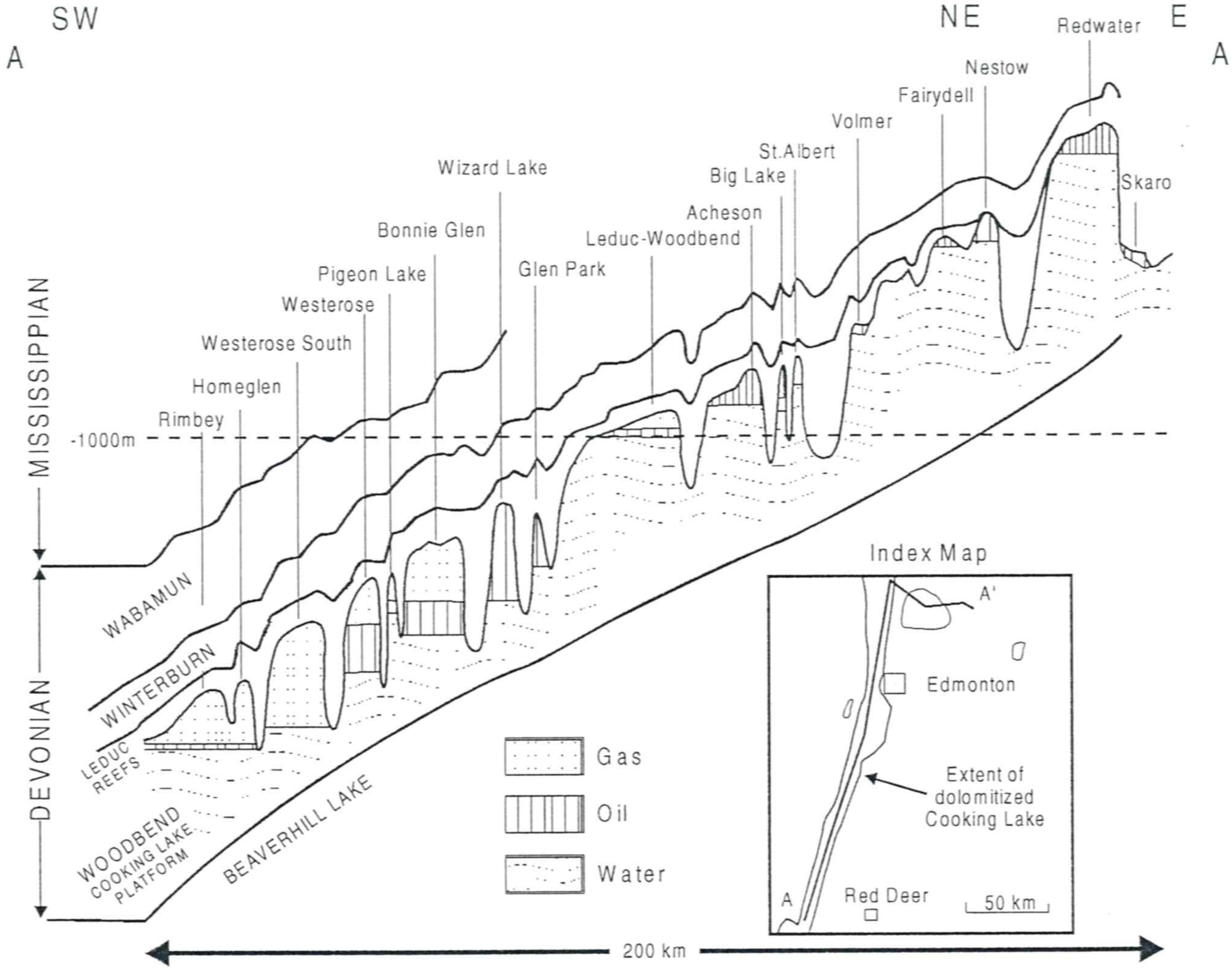

Figure 12.2 Schematic structural cross-section showing the distribution of oil, gas and water in the Leduc reefs of east-central Alberta (modified after Stoakes & Creaney, 1985).

gas over oil, oil over water and finally all water (Fig. 12.2). At the northern end of the trend, Gussow noted that the migration pathway appears to split, with some oil spilling up the main trend into St. Albert (Fig. 1), but most going northeast into the Redwater field. Gussow also wondered if hydrocarbons might continue to migrate updip an additional 200 miles to constitute the Athabasca bitumen deposit. This has not been supported by organic geochemical data (Brooks et al., 1990).

The differential entrapment model generally accounts for the distribution of oil and gas along the Rimbey-Meadowbrook Trend, especially along the lower part of the complex between Rimbey and Wizard Lake. However, there are obvious discrepancies between the ideal hydrocarbon distribution predicted by the model and the one actually observed. For example, certain traps are not filled to their spill points and oil is found in some down dip reservoirs where, according to Gussow's model, there should only be gas. Gussow attributed some of the differences to PVT effects from the burial and uplift of the reservoirs since the emplacement of the oil and gas, but this does not explain why certain traps are not filled to spill point.

To explain these discrepancies, Stoakes and Creaney (1984) proposed a complimentary "leaky pipeline" model. They suggested that the Cooking Lake aquifer acted as an underlying "leaky pipeline", with the amount of oil each reef received being largely dependant on the presence of permeability barriers between the reefs and the underlying platform.

Rostron (1993) noted that Gussow, Stoakes and Creaney and other previous workers had assumed that the cap rocks above the reservoir are impermeable and that any hydrocarbon leakage had to occur via the bottom spill point. He proposed a "leaky caprock" mechanism to explain why certain reservoirs do not contain gas as predicted by Gussow's model or are not filled to their spill points. This could also explain the occurrence of hydrocarbons in Nisku reservoirs. Rostron (1993) used numerical simulations to demonstrate that it was theoretically possible to explain the differences between what is observed in the Rimbey-Meadowbrook Reef Trend and what is predicted by differential entrapment; i.e. it could be due to the cap rocks not being able to retain a full oil column, hence allowing vertical leakage.

Organic Geochemistry

The most detailed examination of oil chemistry along the Rimbey-Meadowbrook Reef Trend was done by Li et al. (1998). These authors confirmed the earlier conclusions of Stoakes and Creaney (1984) that the oils were sourced from the Duvernay Formation and, based on the much higher maturity of the updip oils compared to the surrounding Duvernay Formation, that these oils had migrated long distances (at least 100 km for Redwater and probably significantly longer). Li et al. (1998) were able to split the Rimbey-Meadowbrook Trend oils into two sub-families. These sub-families were thought to most likely correspond to oils generated in the West and East Shale basins (Fig. 12.1) which differ because of minor organic facies differences in the Duvernay Formation between the two basins. The two sub-families of oil would have accessed the Cooking Lake Platform/Leduc Reefs at different entry points. Hence it is possible to explain some of the differences in the distribution of oil and gas along the reef trend from Gussow's model in terms of migration by-pass. Because of the permeability barriers between the Leduc reefs and the underlying platform, the oils may have migrated up "sub-separate" conduits (i.e. the leaky pipelines of Stoakes and Creaney, 1984). This is supported by the lack of apparrent mixing between the two oil sub-families.

Li et al. (1998) also looked at some Nisku reservoired oils that overlie Leduc oils updip from Wizard Lake. The Nisku oils were also found to have a Duvernay source, but tended to be of slightly higher maturity than the oils in the underlying Leduc reefs. This suggests that oils in Nisku reservoirs at fields such as Acheson, Leduc-Woodbend and St. Albert are not from leakage of underlying Leduc reservoirs as suggested by Rostron (1993). Instead, it is more likely that these oils breached the Ireton caprock downdip of Wizard Lake and then migrated up the reef trend in Nisku Formation rocks.

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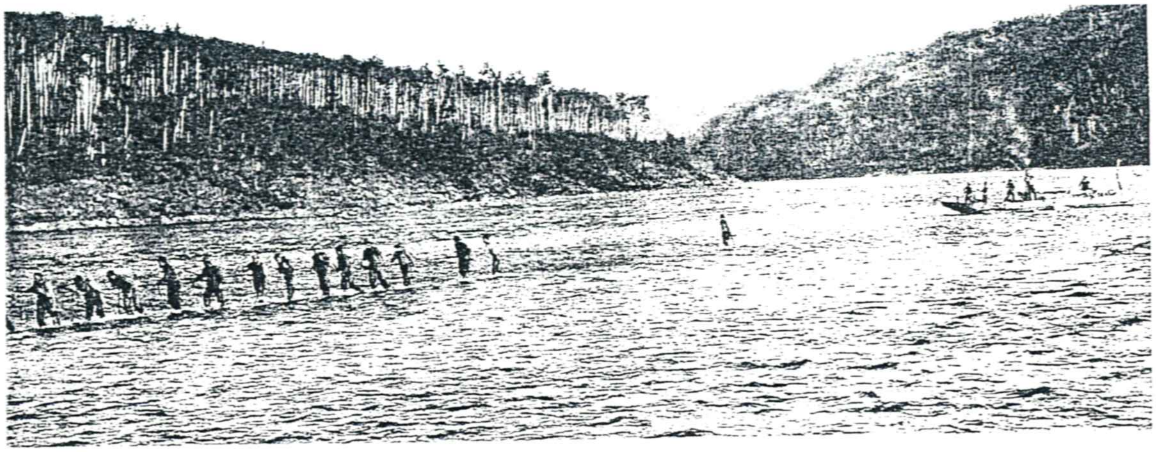

A Geological Survey of Canada field party hauling a scow up the Athabasca River, Alberta, in 1914.

Historical Overview of the Fort McMurray Area

Originally the Athabasca area was inhabited by a number of Metis and First Nations people, including the Cree, Chipewyan, Prairie Dene, and Anzac Metis. According to early government records, the first European to see oil sands was Henry Kelsey, Manager of York Factory on Hudson's Bay, who received in 1719 a sample of oil saturated, bituminous sand, that was delivered to York Fort by a Cree guide, named Wa-Pa-Su. In 1776 Peter Pond, a fur trader and one of the founding members of the Northwest Trading Company (later amalgamated with the Hudson's Bay Company), became the first European to enter the Athabasca region upon crossing the confluence of the Clearwater and Athabasca rivers.

Although the indigenous peoples knew of the bitumen from the oil sands occurring along the Athabasca River, Peter Pond was credited, along with two cases of suspected murder in duels, for first writing about the occurrence of the oil sands in 1778. In 1792 Alexander "Mac" Mackenzie traversed the Methys Portage, crossing the confluence of the Clearwater and Athabasca rivers, and described the oil sands along the outcrops of the Clearwater-Athabasca river system. This was followed by other explorations in 1799 by David Thompson and in 1819 by Sir John Franklin who travelled and surveyed the Athabasca River between Lake Athabasca and the confluence of the Athabasca and Clearwater rivers. The first geological assessment of the oil sands was done by Sir John Richardson in 1848 along his journey to the Arctic to search for the missing Franklin expedition. Sir John Richardson correlated the oil sands with the Devonian shales of the Marcellus Formation of New York and also did acid tests on the oil and microscopic examination of the sand, identifying the principal component as quartz. In 1875 "oil springs" (seeps) were found on the Peace River by John Macoun of the Geological Survey of Canada.

In 1870 a fur trading post, located at the confluence of the Clearwater and Athabasca rivers, was founded by John Moberly and named Fort McMurray after William McMurray who was chief factor of the Athabasca region for the Hudson's Bay Company. The Hudson's Bay Company closed Fort McMurray in 1898 due to a dwindling fur trade, but reopened the fort again in 1912 as a large-freight storage warehouse. Until 1921 there was only river access to Fort McMurray, and the fort served as the gateway to the Arctic. Goods were shipped from Fort McMurray on the Athabasca River to Lake Athabasca, then on the Mackenzie River to the Arctic. River transportation continued as the only access to the North until 1965 when the Mackenzie Highway and the Great Slave Railway were opened. Until this time the shipyards at Fort McMurray were used for building scows, barges and paddle wheelers. As the age of river transportation was closing and railways were being built, the industry of Fort McMurray started shifting to more local resources, including fishing, logging, lumbering, salt, and the newly emerging development of the vast oil sands resources.

In 1906 Count Alfred von Hammerstein, originally from the Prussian army, drilled for oil in the Devonian limestone along the banks of the Athabasca River. He was hoping to discover "free" oil that he thought was a reservoir of pure petroleum underneath the oil sands outcrops. He failed to discover oil, but did find salt at the confluence of the Horse and Athabasca rivers. In 1925 a salt mine was opened on the Horse River by the Alberta Salt Company, which closed in 1927 due to problems with transportation and shipping of salt. In 1936 Industrial Minerals Ltd. opened another salt plant at the town site of Waterways that had rail service to Lac La Biche. At Waterways the salt plant used a hot water pumping process to extract the salt. Hot water was pumped down a shaft to dissolve the salt and the resulting salt-water brine was pumped up within a nearby parallel shaft. The salt brine was then evaporated, the salt retrieved and shipped as table salt until the 1940s. The Waterways salt plant closed in 1950 with the opening of a new salt plant in Elk Point, Alberta.

Fort McMurray served as a military site during World War II and the Cold War. The Canol Project by the United States military was designed to secure safe delivery and supply of oil for North America across the Arctic. The pipeline was started and built at Norman Wells. All troops, supplies and materials for the Norman Wells pipeline were first shipped to Waterways by rail, then from Fort McMurray by barge and boat to Norman Wells. In 1944 oil was shipped along the pipeline from Norman Wells at a cost of $106 U.S. per barrel. During the Cold War a RCAF radar station was established on Stony Mountain south of Fort McMurray as part of the mid-Canada DEW (Distant Early Warning) Line. The Stony Mountain site was dismantled in 1964. In 1989 the railway to Waterways was closed by Canadian National Railway, ending rail service to the area.

Historical Overview of the Oil Sands Industry in Northeast Alberta

An historical overview of the discovery and development of the Athabasca Oil Sands is given in Carrigy and Kramers (1973), with updates presented in Strom (1986), Houlihan and Evans (1988), Wightman *et al.* (1992), Mink and Houlihan (1995), Polikar *et al.* (1998), and Sadler and Houlihan (1998). The first published geological descriptions of the Athabasca oil sands were given by Bell (1884) and McConnell (1893). The McMurray Formation was named by McLearn (1917), with assessments done by the Canadian Government surveys from 1926 to 1949 (Ells, 1926; Government of Canada, 1949; Hume, 1947, 1949). A brief summary of this historical work, and how it relates to commercial development of the oil sands, is given as follows.

For over 200 years, since the first documentation of the oil sands by Peter Pond in 1778, a number of adventurous entrepreneurs, government and industry scientists have greatly invested time, money and effort in the area to build the oil sands industry of today. In 1870 Canada purchased 'Rupert's Land' from the Hudson's Bay Company. Rupert's Land was a vast tract of land that extended from Ontario to the Rockies and north to the Arctic. At that time Dr. Robert Bell served as director of the Geological and Natural History Survey of Canada and in 1882 Bell identified the oil sands as Lower Cretaceous in age, and proposed that the bitumen was sourced in the Devonian strata. During 1882 to 1884 Bell analyzed samples of the Athabasca oil sands; and, at that time, the Survey initiated experiments using hot water to separate the bitumen from the sand. Following this work, Bell proposed that it would be feasible to extract the bitumen from the oil sands by using a hot water extraction process, and that a pipeline could be constructed from Lake Athabasca to the Hudsons Bay to transport the extracted oil to foreign markets. This was followed in 1888 by Bell's report to a Senate Committee, that stated as follows: "The evidence … points to the existence in the Athabaska and Mackenzie valleys of the most extensive petroleum field in America, if not in the world… it is probable this great petroleum field will assume an enormous value in the near future and will rank among [Canada's] chief assets."

In 1888, R. G. McConnell (photo to left, circa 1880, from the Geological Survey of Canada Archives) of the Geological and Natural Survey of Canada gave a geological description of the oil sands and correlated the oil sands with the Cretaceous Dakota sandstone in the Western Interior Basin of the United States. McConnell estimated that the reserves of bitumen in the oil sands were not less than 4.2 million 'long tons,' further suggesting that lighter oil would be found downdip in correlative strata at Pelican Rapids. McConnell agreed with Bell that "The source of these hydrocarbons is probably existing in the porous beds of this Devonian… [and that] The question of their (tar sands) petroliferous character can only be settled in a decided manner by boring." McConnell obtained a $7,000 grant from Parliament to hire a contractor, a drilling rig, and moved the equipment up to the Athabasca River. The well was spudded on August 15, 1894, and after much difficulty in drilling they reached a depth of 1,600 feet at which time 'a roar of gas at a pressure of 500 psi could be heard three miles away." In 1897 McConnell drilled another well downstream from the town site of Redwater along the banks of the North Saskatchewan River. From 1906 to 1910 two vibrant entrepreneurs, the Count Alfred von Hammerstein and "Peace River Jim" Campbell drilled wells in the Athabasca area, hoping to tap into an underground liquid pool of oil that they thought underlie the oil sands.

Although much reconnaissance work on the oil sands was done by other people, the recognized 'Father of the Oil Sands' was Sidney Ells (photo to right a 1930, from the Alberta Provincial Archives), an engineer and Assistant to the Director, Dominion Department of Mines, Mines Branch in Ottawa. Ells was a genius, rogue, entrepreneur and eccentric who studied oil and oil shale occurrences in eastern Canada and the West Indies. Ells was completely obsessed with the Athabasca oil sands and their origins; and, he is quoted as saying "I was so enthralled with the possibilities of the oil sands that I preferred resigning my position rather than being deprived of making an investigation" (McRory, 1982). In 1913 Ells joined the Mines Branch and launched a field party that year to begin a detailed survey of the oil sands in the Athabasca River valley.

Sidney Ells (circa 1930)
(Provincial Archives)

During his first survey of the area, Ells collected 200 samples, totalling nine tons, that were towed by hand on a scow upstream along the Athabasca River to Fort McMurray (title page figure, 1914, from the Geological Survey of Canada Archives). In 1915 Ells continued his reconnaissance work and backpacked out another seventy pounds of oil sands from Fort McMurray to Edmonton in three weeks. Ells lay bituminous pavement in the City of Edmonton and in Jasper National Park as a practical demonstration of the potential use of the tar sands from the Fort McMurray area. During World War I Sidney Ells was a lieutenant in the Royal Canadian Field Artillery. During the war Ells continued to do his own experiments on hot-water separation processes of the bitumen from the oil sands at the Mellon Institute of Industrial Research in Philadelphia (McRory, 1982). In 1926 Ells, along with support from Max Ball, successfully drilled and cored the oil sands in the Mildred Lake – Ruth Lake area, immediately west of both the present Suncor and Syncrude plants, and also drilled and cored wells east of the Steepbank area, and in the Horse River area. Today some of these original cores are stored at the Geological Survey of Canada in Ottawa.

In 1920 D. Diver was the first to try and produce oil from the bitumen by an *in-situ* method. Diver's method consisted of distilling the oil from the oil sands by lowering a heating unit to the bottom of a well near Fort McMurray. In 1920 work on the oil sands also continued at the Alberta Research Council, with the pioneering work of Dr. Karl Clark, a chemical engineer, who in 1925, working with Sidney Blair at the University of Alberta, built a hot-water separation plant at the Dunvegan railyards in Edmonton. This hot-water separation process became the basis for today's thermal-extraction processes. In 1929 the International Bitumen Company, under the leadership of Robert C. Fitzsimmons, opened the first commercial oil sands hot-water separation plant on the Bitumount lease; and by 4,500 drums of asphalt and 2,000 barrels of fuel oil were produced at the Bitumount plant.

In 1936 Max Ball obtained a 6-section lease on the Horse River on which he built an extraction plant. This was followed in 1940 by the Abasand (short for Athabasca Sands) separation plant, built along the Horse River near the present subdivision of Abasand Heights in the town site of Fort McMurray. The Abasand plant, founded by Max Ball along with Sidney Ells, invested a million dollars in research and development. In 1941 the Abasand plant processed 19,000 tons of sand, yielding 17,000 tons of bitumen. This bitumen was then reprocessed into fuel oil, diesel fuel, gasoline and coke. By the time the Canol Project was being built in Norman Wells, the Bitumount plant was shut down, and the Federal Government took over the Abasand plant, which burned down in 1941, rebuilt in 1942 and 1943, destroyed again by fire in 1945. In 1942 the Canadian Government began a reconnaissance drilling and coring program to outline the reserves of the oil sands for war time contingency plans. By 1947 the Canada Mines Branch completed its drilling and estimated reserves of the oil sands to be 1.75 billion tons of commercial grade oil sands. The richest deposit was located at Tar Island, along the Athabasca River, at the location of the present Suncor tailings pond. In 1948, the Alberta government reopened the Bitumount plant and made a commercial test of Clark's hot-water separation process, with production of 500 tons per day.

In 1942 L.R. Champion took control of International Bitumen Company, renaming the company Oil Sands Ltd., which was taken over by Great Canadian Oil Sands Ltd. in 1954. In 1962 Great Canadian Oil Sands Ltd. received permission from the Alberta Oil and Gas Conservation Board to produce 31,500 barrels per day from the oil sands at the Tar Island plant. In 1967 the Great Canadian Oil Sands Ltd., whose controlling interest was held by Sun Oil Company of Pennsylvania, opened the first commercial oil sands plant and showed that the oil sands could be economically developed and that bitumen products could be successfully upgraded to crude oil. The Great Canadian Oil Sands served as the legacy to the Suncor of today.

In the 1950s Royalite, an independent subsidiary of Imperial Oil, also pioneered serious exploration, development and production of the McMurray oil sands. In 1962 Royalite Oil Company formed a consortium with Atlantic Richfield, Cities Service Athabasca Inc., and Imperial Oil Ltd. Royalite was later sold and resold again, the vestiges left in what is now Syncrude, incorporated in 1964. Shell Oil Company of Canada began experiments on *in-situ* steam drive in 1957 on its lease 26, and by 1962 Shell applied to the Alberta Oil and Gas Conservation Board to produce 130,000 barrels per day of bitumen by *in-situ* steam process. In 1978 Shell Canada Ltd. also applied to the Alberta Energy Resources Conservation Board for a 100,000 barrels per day mining operation.

In 1974 the Alberta Oil Sands Technology and Research Authority (AOSTRA) was formed to provide funding and synergies needed for research dedicated to for bitumen extraction and upgrading. Ten years later, in 1984, AOSTRA constructed the Underground Test Facility (UTF) at the present Dover River Project operated by Northstar Energy Ltd. The UTF was used to test horizontal wells and Steam Assisted Gravity Drainage (SAGD) technologies for recovery of the bitumen from the oil sands, which by 1990 more than 60% of the bitumen was recovered (Wightman *et al.* 1992). Although the bitumen deposit at UTF is good and high recovery was achieved, this should not be considered as average conditions for the whole Athabasca deposit. In 1991 Phase B of the UTF began its pre-commercial testing, which now, 9 years later, is now in wind-down stages.

Since the historical and pioneering work, at present both Suncor and Syncrude, have successfully produced synthetic crude oil from bitumen in the oil sands at competitive costs. In 1997 established reserves of crude bitumen were 1021 million cubic metres. Until recently large scale surface strip mines were the only economically viable process for extracting the bitumen. Unfortunately, only about 7% of the vast oil sands deposit is accessible using surface mining techniques, confining exploitation of the resource to the Athabasca River valley where the overburden is thin. Recent technological advances, including *in-situ* bitumen and heavy-oil extraction methods along with improved horizontal drilling, may open up the remainder of the Athabasca deposit for potential development and exploitation. In 1998, total remaining established reserves of crude bitumen under active development were 340 million cubic metres for surface mineable and 240 million cubic metres for *in-situ* schemes (AEUB, 1999).

Along with with extensive research and development on the Suncor and Syncrude leases, there was a parallel stream of scientific and technological pioneering work concerning the other, more deeply-seated bitumen deposits in the Athabasca, Cold Lake and Peace River areas. For example, at Cold Lake the oil-bearing Clearwater Formation is overlain by more than 400 metres of overburden, making it unsuitable for mining techniques. In 1985 Imperial Oil conducted the first Steam-Assited Gravity Drainage (SAGD) experiment at its Cold Lake Production Project that clearly demonstrated the potential of *in-situ* thermal process to recover bitumen from oil sands. Since that time, as a result of the concentrated effort by AOSTRA at the UTF facility, a number of SAGD projects have been developed in the Athabasca, Cold Lake and Peace River oil sand deposits. Some of these other projects included: for the Athabasca deposit -- Syncrude OSLO (Other Six Leases Operation); Mildred, Kearl, and Gregoire lakes; Hangingstone and Tar rivers; for the Cold Lake deposit – Cold, Burnt, Marie, Marguerite and Wolf lakes, Primrose and Lindbergh; and, for the Peace River deposit – the Cadotte Lake project (Figure 13.1)

The bitumen deposits at Cold Lake were discovered in the 1920s. In 1962 Imperial Oil drilled 10 evaluation wells, and in 1963 a pilot plant was built. In 1985 commercial production began at the Maskwa processing plant; and today, the Cold Lake Production Project is the world's largest *in-situ* oil sands steam-generation and bitumen-production operation. Second place, after the Syncrude project, the Cold Lake Project produces about 100,000 barrels of bitumen per day, with production averaging about 35 million barrels per year. Over 30 years of research and technological developments by Imperial, along with 10 years of commercial production, have resulted in various technological schemes including: the development of cyclic steam stimulation (CSS) assisted by formation fracturing; improved water processing techniques; upgrading of well casing designs for cyclic thermal stress; optimization of pad designs and satellite facilities, among other innovations. More than 2,200 producing wells have been directionally drilled from satellite pads at the Cold Lake Production Project. At present, the cyclic steam-stimulation process used at Cold Lake consists of injection of steam under conditions of high temperature and pressure through well bores into the oil sands at depth. Once bitumen melts, and the viscosity is reduced, surface pumps lift the hot water-and-bitumen mixture through the same wellbore to the surface, where separation and processing occurs. Bitumen is blended with lighter hydrocarbons and shipped by pipeline principally to markets in the U.S. Midwest and secondarily to Canadian refineries.

The Future

In the past major companies involved with the oil sands development and production were, for the most part, the large integrated companies or consortia, such as Imperial Oil Ltd., Suncor Energy Ltd. and Syncrude. More recently, in today's market of improved technological methods for recovery and upgrading and improved environmental safeguards (Gray, 1999; Luhning and Luhning, 1999), a number of small and medium-size companies have invested in the oil sands (Table 13.1) (Ross, 1998). At present, according the Oil Sands Developers of Alberta, $24 billion Canadian in projects have been announced for the next decade in the Athabasca, Cold Lake and Peace River oil sands deposits. Part of this shift to development of heavy oil and oil sands, in addition to the technological advances, has been the renovation of North American refineries to increasingly process the heavier crude (Ross, 1998; Auchinleck, 1999; Fisher, 1999).

During the previous twenty years, production of crude oil from the oil sands of Alberta have increased ten-fold (Polikar *et al.*, 1998). Future production of synthetic crude oil from mining and *in-situ* projects is anticipated to increase even more significantly, as refined products from the oil sands replace the depleting conventional oil and gas reserves of the province (Polikar *et al.*, 1998). Along with the technological development for *in-situ* recovery have been improved developments in the mining, upgrading and extraction processes, along with more efficient handling and processing procedures (Sadler and Houlihan, 1998). In September 1999 a dedicated issue of the Journal of Canadian Petroleum Technology, the Canadian Advantage: Oil Sands, highlighted some of these improved methods of in situ and mining operations (Newello, 1999). Overviews included a discussion of Suncor's Project Millennium (George, 1999); updates on the UTF project (Ito and Suzuki, 1999; Komery *et al.*, 1999 and O'Rourke *et al.*, 1999); secondary bitumen recovery from tailings (Cheng *et al.*, 1999); and permeability damage effects associated with thermal recovery at Cold Lake (Zhou *et al.*, 1999).

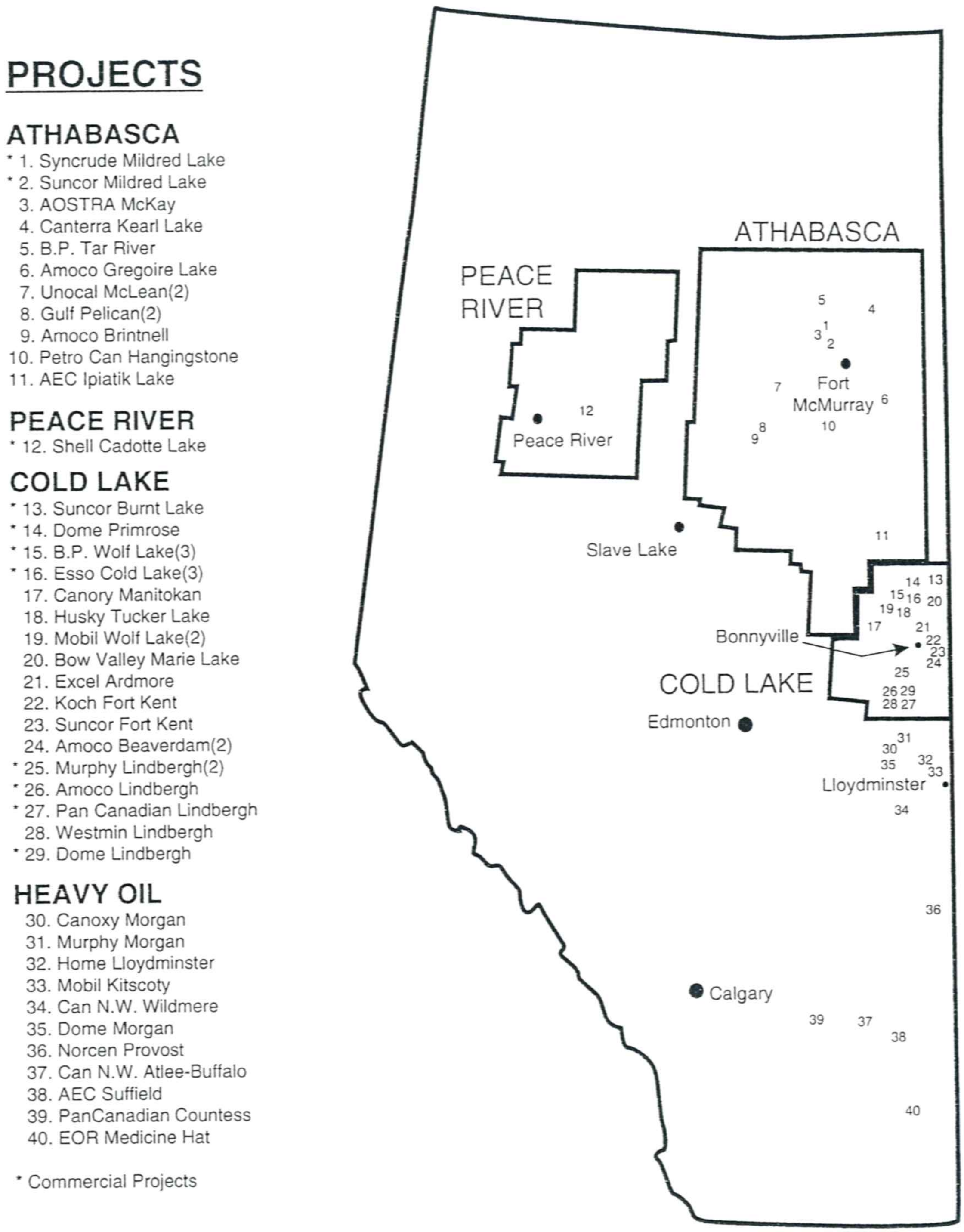

Figure 13.1 Location map showing Alberta oil sands and heavy oil areas with historical thermal projects 1988 (from Houlihan and Evans, 1988).

Coupled with these factors are environmental concerns, mainly focussed on land disturbance, management and reclamation; water and air quality. Land disturbance largely relates to open pit development and overburden and tailings disposal. Water quality is an issue related to tailings disposal from pit mining and for thermal *in-situ* projects obtaining sources of non-potable water, groundwater impacts, and water recycling technology. Finally, air quality relates mainly to emissions of carbon dioxide and other greenhouse gases (Polikar *et al.*, 1998; Sadler and Houlihan, 1998).

At present, the responsibility for environmental issues is shared by Alberta Environmental Protection along with the Alberta Energy and Utilities Board (EUB), through their regulatory review, application and approval process. At present, each new project has to conduct an Environmental Impact Assessment (EIA). In addition, government and industry stakeholders are building environmental databases to be able to assess background environmental levels and thresholds for various environmental impacts associated with both open-pit mining and *in-situ* production plants (Sadler and Houlihan, 1998). Forecasts show substantial increases in production of synthetic crude oil and other byproducts from the oil sands in the next ten years. This increased production and activity will have to be balanced with environmental and socio-economic concerns to bring about a prudent planning and mitigation of major issues involved with the development of this vast resource (Sadler and Houlihan, 1998).

Acknowledgements

The following people are thanked for their helpful reviews of an earlier version of this manuscript: S. Bachu, D. Barson, D. Cotterill, and R. Houlihan. T. Berezniak and C. Kidston aided in computer scanning of the diagrams. Logistical assistance during preparation of the manuscript was provided by the Alberta Energy and Utilities Board, Alberta Geological Survey – Edmonton Office.

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The Western Canada Sedimentary Basin (WCSB) contains enormous reserves of bitumen and heavy oil, 269.8 billion cubic metres (269.8 x 10^9 m^3) in Alberta alone (Alberta Energy and Utilities Board, 1999). The oil sands and heavy oil deposits of the WCSB form three categories or deposit groups (Mossop et al., 1981; Harrison, 1986; Kramers and Mossop, 1987). The first and largest of these groups is the oil sand deposits hosted by Lower Cretaceous sediments. Major deposits include the Athabasca-Wabasca, Peace River and Cold Lake deposits, all located within the Lower Cretaceous Mannville Group or equivalents (Figs. 14.1 and 14.2). The Mannville and equivalents range from 150 to 320 m in thickness, and contain numerous uncemented siliclastic units. In a general sense, the Athabasca and Peace River deposits are single contiguous reservoirs, whereas the southwestern Athabasca (Wabasca) and Cold Lake deposits are made up of a number of stacked reservoirs, separated from one another by impervious shales (Kramer and Mossop, 1987). Bitumens in these deposits have gravities ranging from 8-12°API, and accordingly there is no primary production. Together, the Cretaceous portion of these deposits have been estimated to contain in-place bitumen reserves of about 194 x 10^9 m^3 (Alberta Energy and Utilities Board, 1996).

The second group of deposits consists of the heavy oils of Alberta and Saskatchewan, located in a large number of small reservoirs in the Lloydminster region of Alberta-Saskatchewan and ranging south to the Suffield area of southwestern Alberta (Fig. 14.1). Heavy oils of this second deposit type have gravities in the 15-20°API range, permitting some primary production.

Bitumens hosted by Paleozoic carbonate rocks which subcrop beneath the Cretaceous deposits form the third deposit group, known as the "carbonate trend" (Fig. 14.1). The areal extent of these deposits is poorly known owing to limited well control. Hence reserve estimates range widely from 71 x 10^9 m^3 in-place bitumen (Alberta Energy and Utilities Board, 1996) to 248 x 10^9 m^3 (Outtrim and Evans, 1978), with possible substantial additional reserves in subcropping Paleozoic rocks in Saskatchewan. These bitumens have similar API gravities to the Cretaceous oil sands.

Early reports on the origin of the bitumens in the oil sand deposits were summarised by Vigrass (1968). Vigrass noted that there was evidence suggesting that the Athabasca bitumens are chemically similar to Lower Cretaceous heavy oils such as those from Lloydminster, and thus favoured long distance migration of the hydrocarbons. However, Vigrass (1968) did not consider that these hydrocarbons had been altered. The first major study to make use of organic geochemistry to help elucidate the relationship of the oil sands/heavy oil deposits to each other and to conventional oils within the WCSB was by Deroo and co-workers (1974, 1977). These authors concluded that the Lower Cretaceous oil sands of the Athabasca and Peace River deposits and heavy oils from the Lloydminster area were related to each other and to conventional oils in Lower Cretaceous reservoirs. The bitumen in the oil sands/heavy oils was suggested to be derived from conventional oils by biodegradation and water-washing (Deroo et al., 1977). Later workers supported a common origin of the Lower Cretaceous oil sands/heavy oils, mostly on the basis of biomarker evidence (Rubinstein et al., 1977; Mackenzie et al., 1983; Wardroper et al., 1983; Leenheer, 1984). Hoffmann and Strausz (1986) analysed a few bitumen samples from the Devonian Grosmont Formation and concluded that they were similar to the Athabasca bitumens.

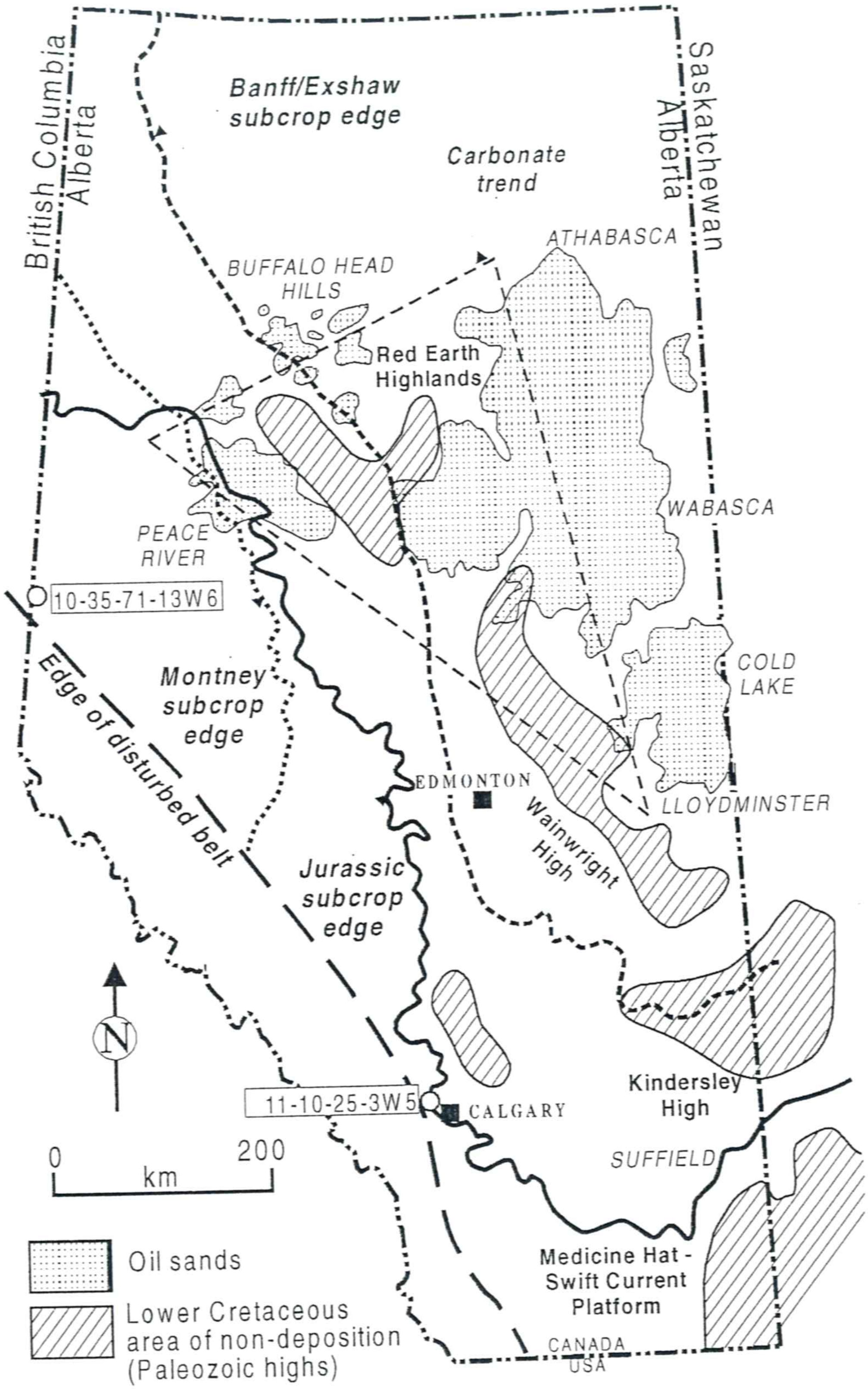

Figure 14.1 Map showing well locations, relavant subcrop edges and Paleozoic highs.

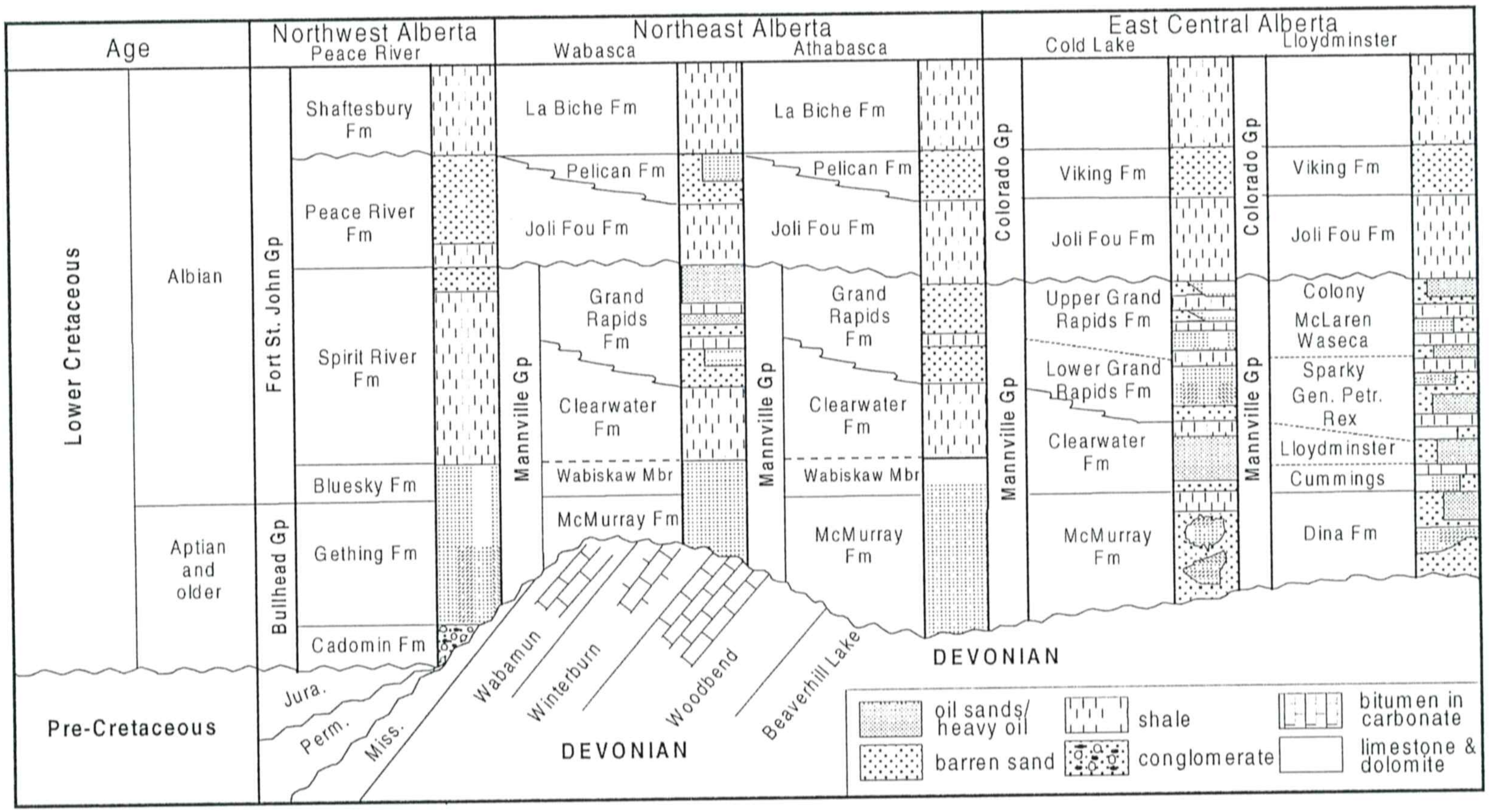

Figure 14.2. Stratigraphic correlation of the Lower Cretaceous of Alberta and subcropping Paleozoic showing units that contain bitumen/heavy oil. (after Kramers, in Mossop, 1984).

There have been numerous suggestions regarding the source rocks for the WCSB oil sands/heavy oils. Deroo et al., (1977) favoured a Lower Cretaceous source unit but because of the volume of bitumen in the oil sands/heavy oil deposits did not rule out some contribution from pre-Cretaceous sediments. Masters (1984) also thought the predominant source was Lower Cretaceous shales, principally the Clearwater shale of the Mannville Group, although he accepted that Triassic and Jurassic "dark shales" may have made a contribution. Moshier and Waples (1985) doubted, on mass balance considerations, if Mannville Group rocks could be a major source of the Lower Cretaceous hydrocarbons in the WCSB and concluded that Paleozoic and other Mesozoic rocks had to be important sources. Du Rouchet (1985) suggested that only Triassic-Jurassic basinal black shales and more hypothetically a euxinic basinal facies of the Wabamun Formation (Upper Devonian) could be productive enough, if sufficiently developed in the current location of the Rocky Mountains, to have supplied a substantial part of the hydrocarbons. A recent detailed survey of possible Devonian source rocks in the WCSB did not indicate a Wabamun potential source rock with sufficent potential to be a significant contributor to the tar sands/heavy oils (Fowler, unpublished results). Leenheer (1984) thought that some Alberta heavy oils correlated well with the Mississippian-aged Bakken Formation of the Williston Basin.

In the late 1980's, a group from the Geological Survey of Canada investigated the relationship of the Cretaceous tar sands/heavy oils to each other, to 'carbonate trend' bitumens and to conventional oils principally using biomarkers (Fowler and Brooks, 1987; Brooks et al., 1988a, 1988b; 1989, 1990). This work led to the following conclusions:

a) the tar sands/heavy oils are derived from a mature conventional oil that must have migrated over long distances, suffering extensive biodegradation in place and possibly during migration.

b) the level of biodegradation is variable, but generally there is a trend of increasing biodegradation from west to east, and there has been more than one biodegradation pathway.

c) once the effects of biodegradation are taken into account, all the Cretaceous oil sands/heavy oils are very similar suggesting that despite their widespread geographic and stratigraphic distribution, they had the same or a very similar source rock.

d) 'carbonate trend' samples from units such as the Devonian Grosmont and Nisku, and Mississippian Debolt and Shunda formations tend to be more biodegraded than Cretaceous samples. Based on the presence or absence of one biomarker compound, two sub-families of carbonate trend bitumens were identified but generally they are extremely similar to each other and to the Cretaceous tar sands/heavy oils suggesting that they have the same or similar source.

e) biomarker geochemistry did not support the proposal of Gussow (1954), Stoakes and Creaney (1984) and others that 'carbonate trend' and Mannville Group tar sands deposits in the Athabasca deposit have a significant contribution of hydrocarbons from the Duvernay Formation that had migrated further updip from the Leduc Formation reservoirs along the Rimbey-Meadowbrook Reef Trend.

Around the same time, a group at Esso were investigating the petroleum systems of the WCSB (Creaney and Allan, 1990; 1992; Allan and Creaney, 1991). While these authors also thought that the Cretaceous tar sands/heavy oils were the result of the biodegradation of conventional oil, they suggested that the bitumens were derived from a number of sources. These in order of importance, were the Lower Jurassic Nordegg Member, Devonian-Mississippian Exshaw Formation, Middle Triassic Doig Formation and the Upper Devonian Duvernay Formation with the first two being the principle sources. Unfortunately, this was not supported by published data. Creaney and Allan (1990) also used mass balance considerations to suggest that no single source was sufficient to have generated the necessary volume of hydrocarbons. However, this argument appears to be flawed by the restricted drainage area, especially for the Exshaw Formation, chosen by Creaney and Allan (1990).

Creaney et al. (1994) is a summary of the work done by the Esso and GSC groups up to that time and it is clearly evident from this article that there was a disagreement between the two groups over the origin of the tar sands/heavy oils.

Piggott and Lines (1992) also thought that tar sands/heavy oils were derived from a mixture of sources, with Mesozoic sources (Doig and Nordegg) the most important for the Peace River deposit and Exshaw and Duvernay more important for other deposits.

Riediger (1994) discusses the claims for a Nordegg contribution to the Cretaceous tar sands/heavy oils by Creaney and Allan (1990, 1992) and Piggott and Lines (1992). She showed that this was not supported by organic geochemical evidence or by the regional stratigraphy which indicated that the Nordegg was rarely in contact with the presumed carrier beds. Riediger (1994) presented mass balance considerations that indicated the Nordegg could at best have been a minor contributor to the total bitumen present in the Cretaceous deposits, generating hydrocarbons only sufficient to fill the Peace River deposit.

Recently Riediger and co-workers have shown that most of the Mannville Group heavy oils in southern Alberta (Provost and south) that occur east of the Jurassic Rierdon subcrop edge have an Exshaw Formation source, with some having a contribution from the Lower Cretaceous Ostracode Zone (Karavas et al., 1998; Riediger et al., 1999).

Other theories have been proposed for the origin of the tar sands/heavy oils with various degrees of seriousness including:

1) the "immature oil theory"- conversion of organic matter soon after burial into "proto-oil" via microorganisms (Wilson, 1990).
2) polymerisation of methane released from gas hydrates (A. Judge, Globe and Mail, circa 1988).
3) "anhydrite theory" of Hunt (1999) who believes in an abiogenic origin of the bitumen which was expelled from the crust along with the quartz sandstones it is now hosted in.
4) "intergalactic oil freighter" hypothesis of Snowdon (1997).

While these theories are certainly interesting, we believe that the bitumen in the tar sands and heavy oils represents biodegraded mature oil.

Based on published data, such as that discussed above, and some unpublished data, the present authors consider the following the most likely scenario for the origin of the tar sands/heavy oils. The data published by us and our co-workers over the last 10+ years we feel has indicated that all the tar sands/heavy oils both in Cretaceous and Paleozoic rocks have a similar source rock which is the same as that of the majority of Mississippian and Lower Cretaceous conventional oils. The source rock with the closest biomarker characteristics to these bitumens and oils is the Exshaw Formation. This is also the only major source rock with the areal extent to source oils or biodegraded oils with similar biomarker characteristics observed in reservoirs from north east British Columbia to northern Montana. There may be contributions from other source rocks, although at present this has only been unequivocally shown for the Lower Cretaceous Ostracode Zone in southern Alberta (Riediger et al., 1999). The data available for some deposits (notably the Peace River deposit) are sparse, hence further work could indicate a contribution from other source rocks.

Timing of Hydrocarbon Generation and Migration

Burial history models from southern (11-10-25-3W5) and west-central Alberta (10-35-71-13W6; See Figure 14.1 for locations) illustrate the difference in timing of hydrocarbon generation from the Exshaw in these two regions. In west-central Alberta, in the Peace River Embayment (PRE) region, thick successions of Upper Paleozoic and Lower Mesozoic (Triassic) strata were deposited and preserved, resulting in the earlier onset of hydrocarbon generation from the Exshaw in this region. Peak hydrocarbon generation occurred between about 107 Ma and 87 Ma (Figure 14.3), significantly earlier than the southern region, where the Exshaw did not achieve peak hydrocarbon generation until about 56 Ma (Figure 14.5). In the south, Upper Paleozoic strata are thinner, and Triassic strata are absent, and as a result peak hydrocarbon generation did not occur until thetime of the Laramide orogeny (Paleocene-Eocene).

The implications of this relative timing for the migration of Exshaw oil is significant. If these burial history models (i.e. Figs. 14.4 and 14.5) are reasonable, then migration of Exshaw oil from the vicinity of the modeled well at 10-35-71-13W6 would have been occuring at about the same time as deposition of the Upper Mannville strata in eastern Alberta. If we consider that the Exshaw Formation extends considerably further west than the modeled well location, and that the Upper Paleozoic and Triassic section thickens westward (Richards, et al., 1994; Edwards et al., 1994), then the Exshaw source rock in the west would have entered the oil window and expelled hydrocarbons even earlier than the modeled well. This is confirmed by 1-D models for wells close to the edge of the Foothills Belt in northeastern B.C. (e.g. C-27-E/93-P-6; Shona Ness, unpublished data), which indicate that the Exshaw entered the main zone of hydrocarbon generation as early as Early to Middle Triassic. If this scenario is correct, Exshaw oils in Mississipppian reservoirs below the Peace River tar sands and Grosmont reservoirs below the Athabasca tar sands could have been biodegraded prior to, and/or during Lower Mannville deposition. This may account for the higher degree and differing nature of biodegradation relative to the Mannville tar sands bitumens. Based on Lower Mannville paleogeography (Figure 14.1), and given the proposed timing of hydrocarbon generation and migration for Exshaw oils, we suggest that Exshaw sources in the area of the PRE may have provided most of the oils found in the Peace River, Buffalo Head Hills, Athabasca and Wabasca deposits. In the absence of suitable traps along the migration fairway, much of the oil continued to migrate updip eastwards, from the source area, until it reached the surface in the area of the Athabasca tar sands and other tar sand deposits. The Mannville reservoirs cannot have been very deep when filled by the oil as evident from the low amount of sediment diagenesis. Tar sand samples from the Athabasca area are often just loose quartz grains cemented by the bitumen which after extraction of the bitumen resemble beach sand. Hence biodegradation could have taken place during the later stage of migration or after the oils were in place. The uplift that occurred in the WCSB following the Laramide Orogeny in the Early Tertiary would have caused hydrocarbon generation and migration to stop and brought the reservoirs nearer to the surface thereby further facilitating biodegradation which has continued to the present.

Hydrocarbon generation from the Exshaw Formation in southern Alberta did not commence until Tertiary time (about 56 Ma at 11-10-25-3W5), during the Laramide orogeny. Burial history modeling in the Moose Mountain area (southwestern Alberta) by Ardic (1998) showed that even in the area of the present day Front Ranges, hydrocarbon generation from the Exshaw Formation occurred just prior to overthrusting in the latest Cretaceous-Paleocene time. Oils generated from the Exshaw Formation in southern Alberta migrated at least as far as Provost, and possibly as far as Lloydminster (eastern Alberta) and Aberfeldy (western Saskatchewan). This later episode of hydrocarbon generation and migration may account for the generally lower levels of biodegradation observed in these fields. It is also consistent with the more consolidated nature of the host reservoir rocks, which were lithified prior to filling, unlike stratigraphically equivalent tar sands reservoirs to the north.

While the present day reserves of tar sands/heavy oil bitumen are enormous (almost 2 times the conventional reserves of the Middle East), as they represent the biodegraded residuum of conventional oils, the original volume of conventional oil must have been considerably greater. Based on a comparison of the gross composition of the Athabasca tar sand bitumens and conventional Mannville oils , at least 3-4 times more conventional oil was generated to create this deposit.

Acknowledgements

Burial history models (Figures 14.4 and 14.5) were provided by Taskin Akpulat (unpublished data).

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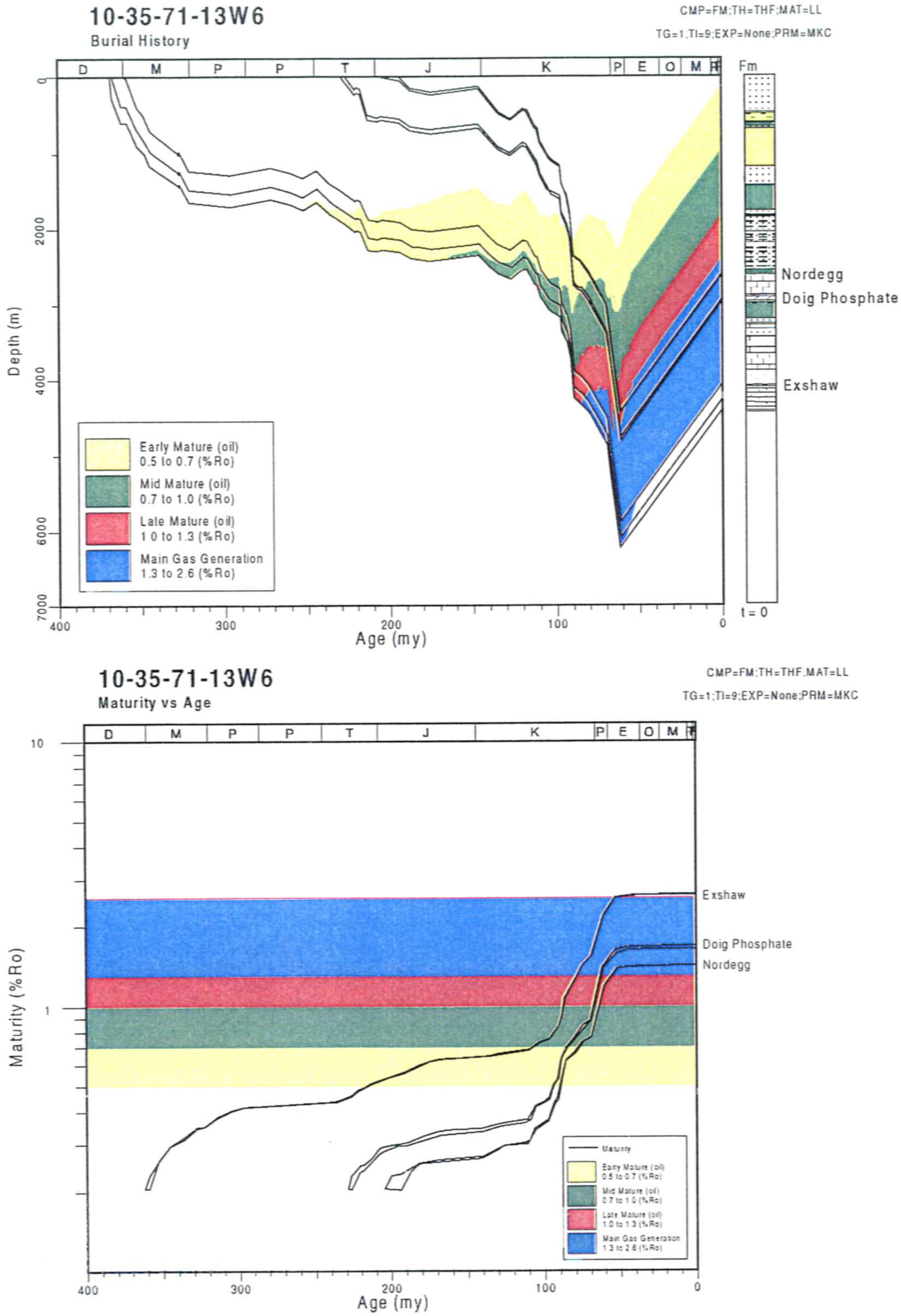
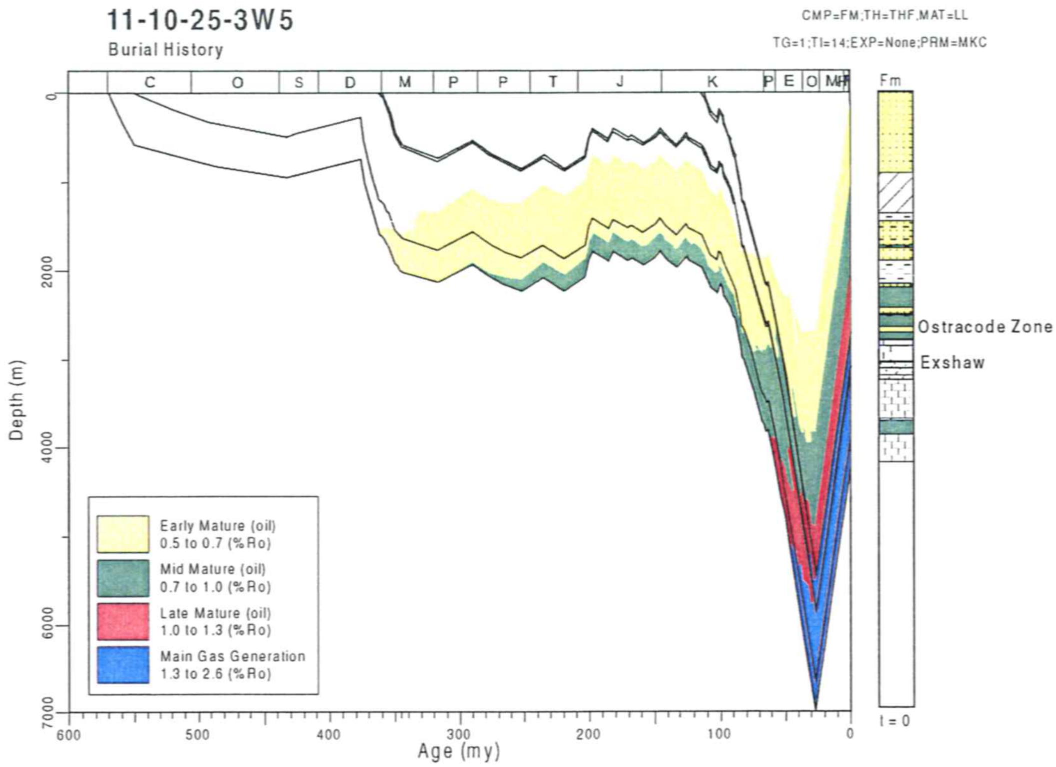


Figure 14.3 Burial history and maturity vs. age curves, 10-35-71-13W6.



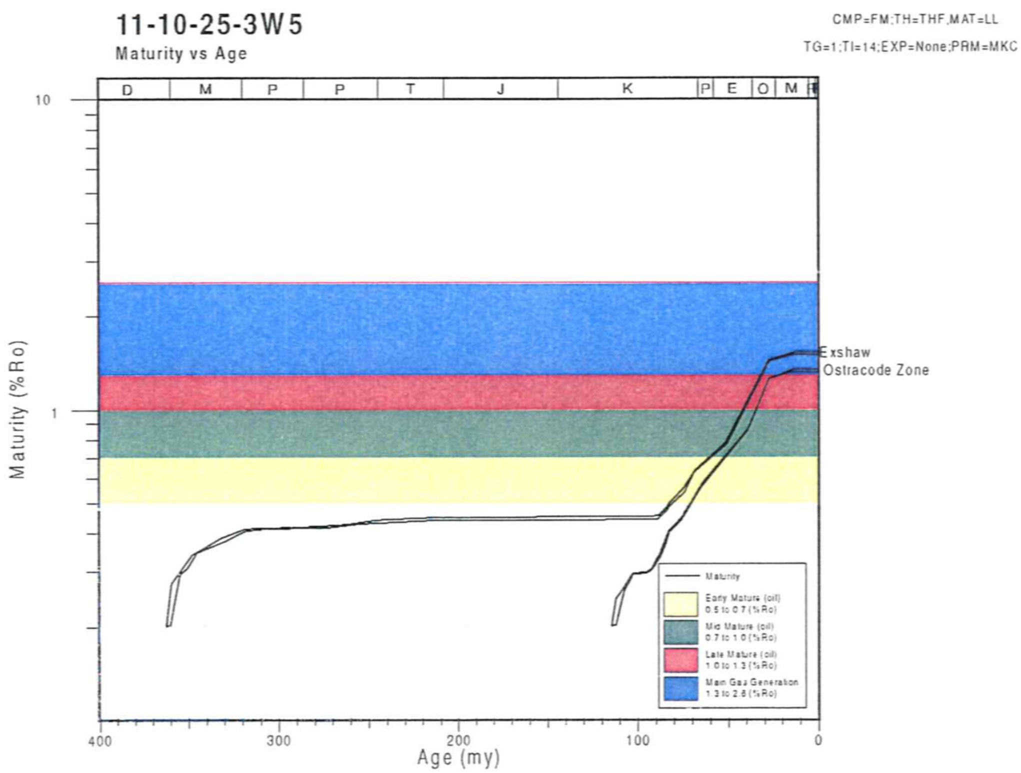


Figure 14.4 Burial history and maturity versus age curves, 11-10-25-3W5.

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Introduction

Four major oil sands deposits occur in northern Alberta – the Athabasca, Wabasca, Cold Lake and Peace River (Figure 15.1). These deposits account for 40% of the world's resources of bitumen, with total reserves of bitumen estimated at more than 1.7 trillion barrels, of which about 300 billion barrels are ultimately recoverable (Masson and Remillard, 1995). In 1995, 1996 and 1997 drilling and production from the oil sands reached record levels for bitumen and synthetic crude oil in Alberta. In 1998 oil sands drilling included 762 wells, a decrease by 71.8% from the three previous record-breaking years (AEUB, 1999). However, in 1998, despite the lower drilling record, the bitumen and synthetic crude productions reached record levels. Production was up 12.1% to 34.3 million cubic metres, compared with 30.6 million cubic metres in 1997 (AEUB, 1999). Oil from oil sands accounted for 36.4% of Alberta's total oil production in 1998.

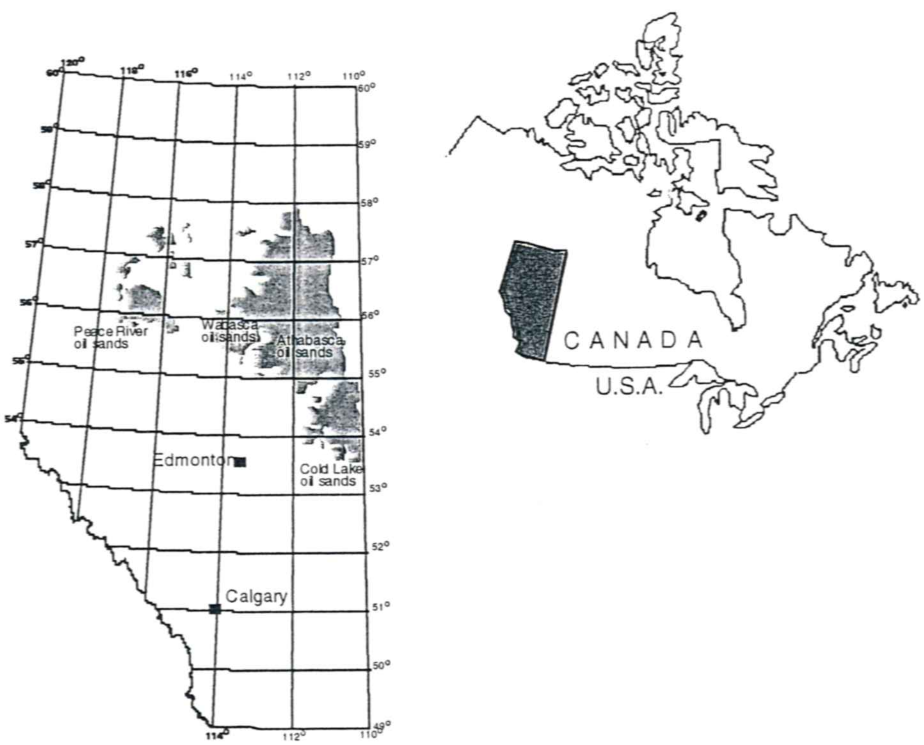

Figure 15.1: Location map of the Athabasca, Cold Lake, Peace River and Wabasca oil sands

At the end of 1998, total remaining established reserves of crude bitumen from remaining reserves of *in-situ* bitumen under active development showed an increase due to an update of reserves for commercial projects and primary and experimental schemes. Remaining reserves of *in-situ* bitumen under active development totalled 450 million cubic metres (2 832 million barrels) an increase of 176 million cubic metres (1 108 million barrels) from the previous year (AEUB, 1999). By comparison, Alberta's remaining established reserves of conventional crude oil are estimated to be 315.2 million cubic metres (1 984 million barrels) (AEUB, 1999). As stated by the AEUB (1999), conventional oil production continues to outstrip additions to conventional crude-oil reserves since 1973, while synthetic crude oil production from the oil sands has continued to fill the gap left by the declining conventional oil reserves (AEUB, 1999).

Previous Work

An historical overview of the discovery and development of the Athabasca Oil Sands is given in Carrigy and Kramers (1973), with highlights from their compilation reprinted in Wightman and Pemberton (1992). A number of field guides have been written about the geology of the Fort McMurray area, with emphasis on the oil sands (Carrigy, 1959; Carrigy and Kramers, 1973; Kramers, 1973; Mossop *et al.*, 1982; Stewart and MacCallum, 1978; Wightman and Pemberton, 1992). Selected applications of outcrop analogues to detailed subsurface reservoir characterization have been done at the Dover River Project by Strobl *et al.* (1997a, b) and in the Steepbank area by Flach (1977, 1984) and Langenberg *et al.* (1999). An update of a field guide to the oil sands of the Fort McMurray area is presently being prepared by Cotterill *et al.* (in prep.) that incorporates the unified lithofacies scheme (Table 15.1), revised stratigraphy of the McMurray Formation (Hein *et al.*, in prep.) and application of sequence-stratigraphic concepts.

Stratigraphy

The stratigraphic section preserved in outcrop in the Fort McMurray area (Figure 15.2) includes the uppermost portions of the Devonian Christina and Moberly Members of the Waterways Formation (Beaverhill Lake Group) and the overlying Lower Cretaceous McMurray Formation and Wabiskaw Member of the Clearwater Formation (Mannville Group).

The outcrop sections lie along river valleys of the Athabasca River and its tributaries, mainly in the Fort McMurray area of northeast Alberta (Figure 15.3). The unconformable contact between the Devonian and Cretaceous successions has significant relief (Figure 15.4), a result of profound differential weathering of the variably argillaceous carbonate units, combined with tectonic collapse caused by dissolution of underlying Elk Point Group salts. In the Fort McMurray area, positive structural elements along the pre-Cretaceous unconformity surface include the Grosmont High and the Beaverhill Lake High. Negative structural elements are the Bitumont Basin and a regional linear depression, called the Prairie Salt Scarp, that trends roughly parallel to the strike of the sub-cropping Devonian units (Figure 15.4). Collapse of the carbonate units, after regional dissolution of the underlying salts, resulted in small-scale folding and faulting in areas proximal to the dissolution front. Later karstification along the sub-Cretaceous unconformity created numerous sinkholes and other paleokarst features. The highly variable structural and erosional relief on the sub-Cretaceous unconformity greatly influenced sediment dispersal patterns and facies architecture of the overlying McMurray Formation and the Wabiskaw Member of the Clearwater Formation (Figure 15.5).

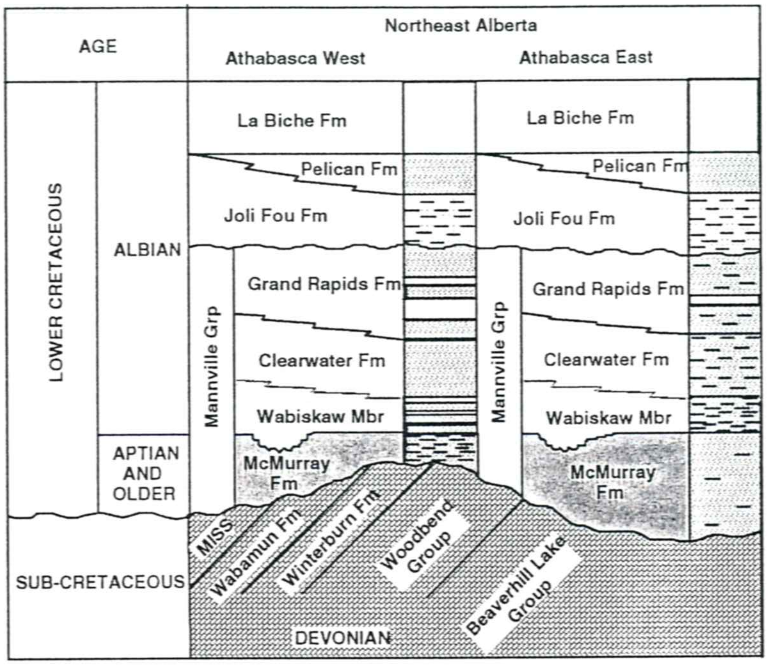

Figure 15.2: Schematic cross section, Fort McMurray area. Solid shading for McMurray Formation indicates primary bitumen saturation, secondary bitumen saturation in the Clearwater and Grand Rapids formations *(modified from Wightman* et al., *1995).*

Facies Classification and Depositional Environments

Detailed sedimentological and stratigraphic analysis of 15 outcrops, 140 cores and stratigraphic picks from over 4 000 well logs, along with preliminary palynological analysis, allow for a better understanding of the preserved stratigraphy and depositional settings of the bituminous McMurray Formation (Hein *et al.*, in prep.). Although there is a high degree of heterogeneity within the McMurray Formation, much of this apparent heterogeneity can be simplified when a unified facies classification is used (Hein *et al.*, in prep.) (Table 1).

Facies analysis indicates that the Lower Cretaceous McMurray Formation was deposited and reworked as fluvial, estuarine and coastal plain sediments within an evolving landscape that changed from incised-valley fills carved on a regional unconformity, to broad estuaries, lakes and bays on a coastal plain. Locally, the weathered Devonian limestone highs pierced the landscape. Sedimentation on top of bedrock highs was typically low resulting in localized condensed sections. Elsewhere, the complete stratigraphic succession is often preserved within incised paleovalleys with high sedimentation rates. The Lower Cretaceous McMurray Formation records a sedimentary history of repeated erosional and depositional cycles, resulting in significant unconformities at the base and top, and internal disconformities within the succession.
McMurray Formation and Reservoirs

The McMurray Formation is the lowermost siliciclastic unit within the Lower Cretaceous Mannville Group in northeast Alberta (Cant and Abrahamson, 1996). The succession is bounded unconformably at the base and the top, and has internal disconformities, locally disrupting the McMurray succession. The basal pre-Cretaceous unconformity, as previously mentioned, has significant relief, and had a profound effect on sediment distribution and depositional facies patterns within the McMurray Formation. The top of the McMurray Formation has been removed by post-Cretaceous erosion along and proximal to the present-day drainage system and within other localized areas in the subsurface. The youngest of these valley incision events was during the Quaternary Period, with some Quaternary channels incising over 100 metres into the underlying Cretaceous bedrock.

The McMurray Formation was deposited on an exposed karstic landscape of ridges and valleys, with local paleosols, and varies in thickness from being absent over Devonian highs to over 130 m thick in the Bitumont Basin. There is an increase in complexity of facies associations as assigned to the Lower and Upper McMurray Formation, concomitant with an increase in facies heterogeneity and interpreted lack of stability in the location of facies tracts. Bitumen-sand reservoirs accumulated as incised paleovalley-fills cut within the karstic pre-Cretaceous landscape and are within the Lower McMurray fluvial-dominated lowstand deposits. Reservoirs occur mainly within braided channel-and-bar sands. Local water sands occur in paleolows along the basal pre-Cretaceous unconformity, and may pose problems for SAGD production of the oil sands. Bitumen-rich reservoirs formed within estuarine valleys stacked above the Lower McMurray channel sands and are assigned to the Upper McMurray Formation. These bitumen-sand reservoirs occur mainly within stacked estuarine-tidal channel-and-point bar complexes. Local water-sands occur in the lower parts of the Upper McMurray, whereas in the upper parts gas - reservoirs are common. Bitumen-, water- and gas-reservoirs formed within prograding coastal plain, as part of the Upper McMurray estuarine and coastal plain complex. Reservoirs in this part of the succession occur in stratigraphic and structural traps, particularly in areas susceptible to salt dissolution and tectonics of the pre-Cretaceous bedrock.

The McMurray Formation is notorious for having very complex sedimentary facies relationships that change both laterally and vertically over very short distances. The highly variable topography on the basal unconformity combined, to a lesser degree, with the upper erosional surface (Wabiskaw/McMurray contact) greatly influences the thickness of the McMurray Formation (Figure 15.6). The north-south trend in the McMurray Formation thickness correlates with location of the salt dissolution zone running generally north-northwest from Ranges 1W4 Meridian to 8W4 Meridian, Townships 72 to 90. North of Fort MacKay the thickening trend of the McMurray succession has an east-west orientation from Range 7W4 Meridian to 13W4 Meridian, within Townships 94 to 96. This trend corresponds to an axial trend of the Bitumont Basin (Figures 15.4 and 15.5).

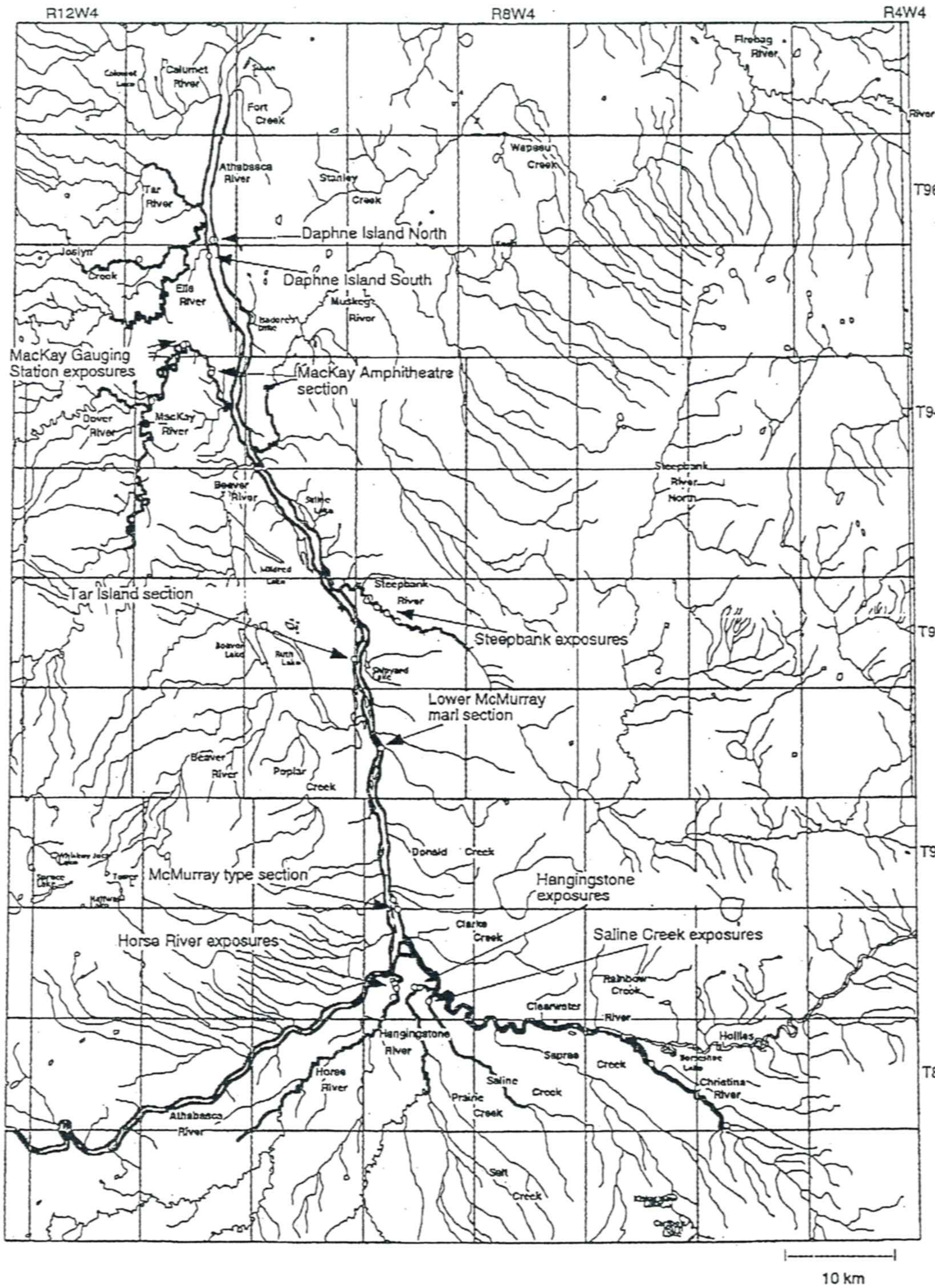

Figure 15.3 Distribution of major outcrop sections of the McMurray Formation along the drainage system of the Athabasca River, form Township 87 - 97 and Range 4 West of the 4th Meridian to Range 12 West of the 4th Meridian. Horizontal scale bar is 10km.

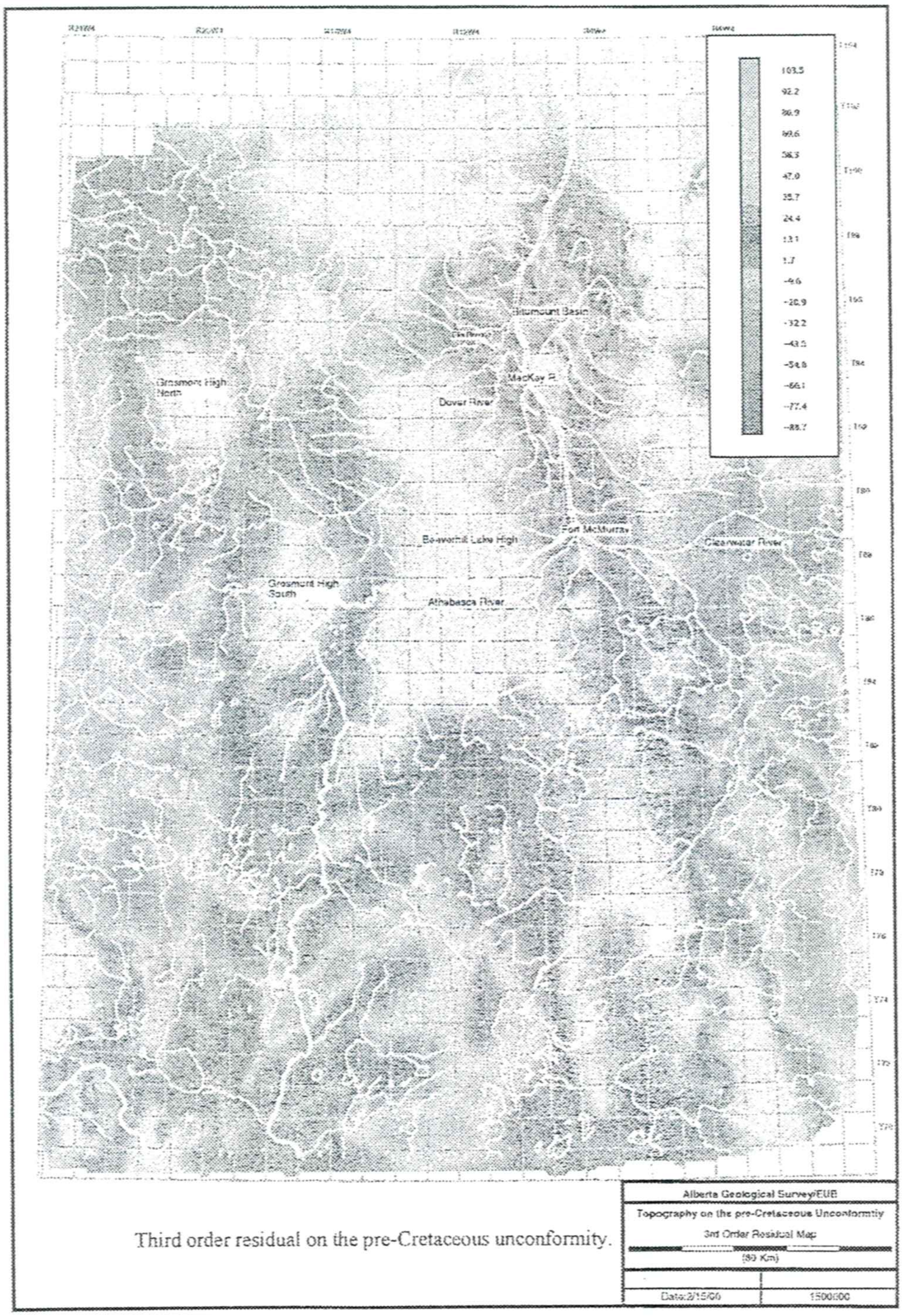

Figure 15.4 Topography of the sub-Cretaceous uniformity as shown by a third-order residual map on the sub-Cretaceous unconformity surface, from Township 69 - 104 and Range 4 West of the 4th Meridian to Range 12 West of the 4th Meridian. Major drainages and topographic features are also shown. Horizontal scale is 80 km.

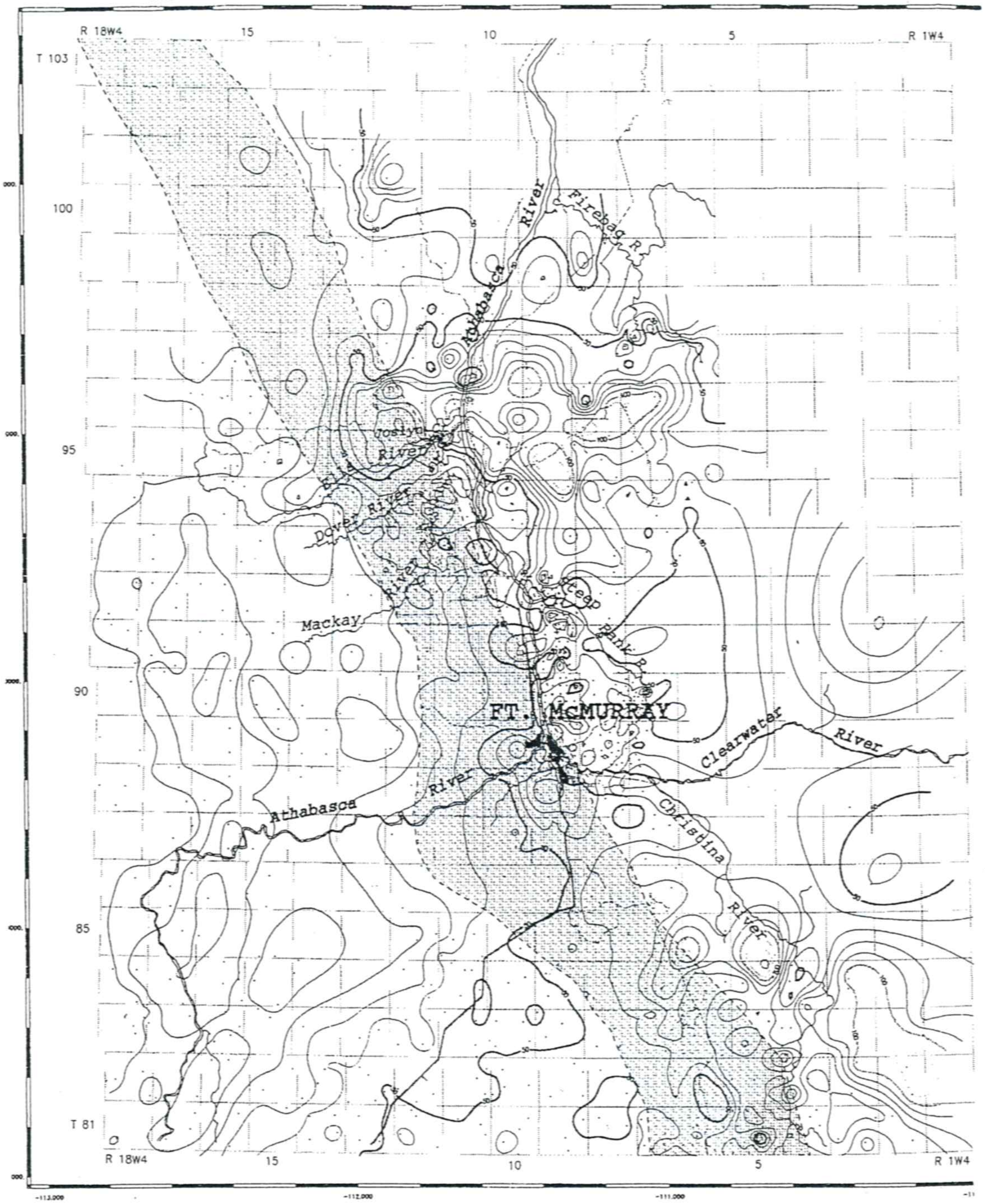

Figure 15.5 Isopach Map of the McMurray Formation with the Salt Scarp shown in shaded area, from Township 81 - 103 and Range 1 West of the 4th Meridian to Range 18 West of the 4th Meridian. Contour interval is 10 m. Horizontal scale bar is 60 km. Map Scale 1:1 000 000.

Figure 15.1 Facies Classification, McMurray Formation, Athabasca Oil Sands Deposit, Fort McMurray area (from Hein el al., In prep.).

Facies Number	Lithology (rare)	Sorting	Sedimentary Structures	Bioturbation Intensity	Average Bed Thickness (range)	Paleo-Environment
1	pebbly coarse sand (gravel)	poor to very poor	Trough Cross Beds	None	1m (0.1 – 9 m) (multistory)	Braided Fluvial Channel
2	gravel (muddy)	v. poor to poor	Variable Grading	None	0.3 m (0.1 – 3 m)	Colluvium Debris Flow
3	siltstone mudstone coaly carbonaceous	good to poor	Massive or Graded-Laminated	None to Moderate (Rooted)	0.75 m (0.05 – 3 m)	Bog, Slough Overbank Paleosols
4	sand – siltstone mudstone (calcareous)	moderate to poor	Massive or Laminated	Moderate to Heavy (rooted)	0.3 m (0.05 – 2 m)	Paleosols
5	fine to medium sand	good to moderate	Trough Cross Beds	Rare to Less common	0.75 m (0.5 - > 1 m)	Fluvial or Estuarine Channel
6	fine to pebbly sand	very good to moderate	Planar Cross Beds	Rare to Less common	0.75 m (0.5 - > 1 m)	Fluvial or Estuarine Channel
7A	mudstone breccia, sand matrix	poor to very poor	Massive Laminated Cross Beds	Rare to Very Common	0.5 m (0.05 – 3 m) (multistory)	Fluvial or Estuarine Channel
7B	sand, siltstone &/or mudstone	poor to very poor	Slump Structures	Rare to Less Common	1.5 m (0.05 – 3 m) (multistory)	Slides, Slumps Debris Flows
8A	fine to coarse sand	moderate to good	Massive	rare	0.5 m (0.05 – 3 m) (multistory)	Fluvial or Estuarine Channel
8B	siltstone and muddy siltstone	moderate to poor	Massive	rare	0.02 m (0.01 – 0.3 m)	Overbank
9A	fine to very fine sand	good to very good	Rippled, Ripple-drift	rare to uncommon	0.5 m (0.01 – 4 m) (multistory)	Fluvial or Estuarine Channel
9B	fine to very fine sand	good to very good	Flaser Rippled	rare to common	0.5 m (0.01 – 4 m) (multistory)	Tidal Estuarine Channel
10A	fine to very fine sand, with muddy interbeds	good to very good	Low-angle Inclined Bedding	rare to very common	3m (1 - > 15 m) (multistory)	Sandy Tidal Estuarine Point Bar
10B	mudstone, with sandy interbeds	good to very good	Low-angle Inclined Bedding	rare to very common	3m (1 - > 15 m) (multistory)	Muddy Tidal Estuarine Point Bar

Figure 15.1 (cont) Facies Classification, McMurray Formation, Athabasca Oil Sands Deposit, Fort McMurray area (from Hein el al., In prep.).

Facies Number	Lithology (rare)	Sorting	Sedimentary Structures	Bioturbation Intensity	Average Bed Thickness (range)	Paleo-Environment
11	very fine to medium sand	good to excellent	Horizontal Lamination	rare to common	0.3 m (0.1 – 3 m)	Fluvial or Estuarine Channel Overbank
12	very fine to medium sand and silty mud	good to excellent	Rhythmic Tidal Lamination	variable, absent to very common	2 m (0.2 – 5 m)	Fluvial or Estuarine Channel Overbank or Tidal Flat
13A	very fine to muddy sand	poor to very poor	Churned	very high to intense	2 m (0.2 – 5 m)	Fluvial or Estuarine Channel Overbank or Tidal Flat
13B	silty mudstone	poor to very poor	Churned	very high to intense	2 m (0.2 – 5 m)	Fluvial or Estuarine Channel Overbank or Tidal Flat
14	sandy/silt coaly mudstone	poor to moderate	Massive Laminated Rooted	rare to high (rooted)	0.3 m (0.1 – 0.75 m)	Paleosols Overbank
15	mud, silt sand	good	Upward Coarsening, Laminated Cross Beds	rare to high	1 m (0.5 – 3 m)	Crevasse Splays, Overbank
16	very fine to fine sand	good to excellent	Wave Rippled Swaley Convolution	rare to high	0.25 m (<0.01 – 0.75 m)	Waves Lakes Tidal Flat Overbank
17	clayey sidertized carbonate	poor to very poor	Nodular Mottled Weathered	rare to moderate (rooted)	0.25 m (<0.01 – 0.75 m)	Colluvium Paleosols
18	calcareous marl	poor to good	Massive Laminated Ripped Slumped	rare	0.25 m (<0.01 – 0.75 m)	Colluvium Paludal Lakes
19	mixed calc- & siliciclastic	very poor to poor	Karstic Brecciation Slump Slides	none	2 m (0.5 – > 5 m)	Colluvium Karst Fill

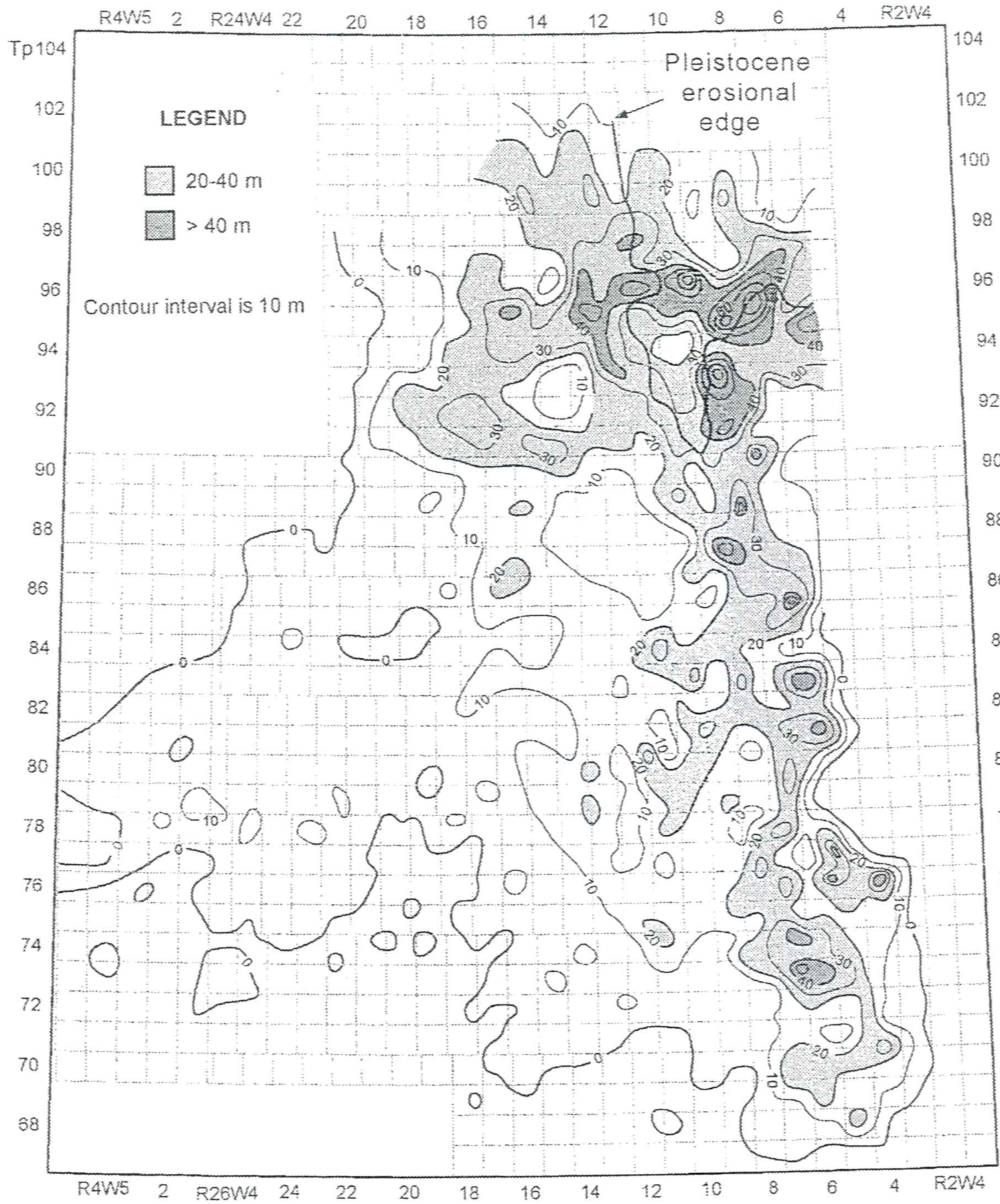

Figure 15.6 Sand isopach of the McMurray Formation/Wabiskaw Member interval, with shading indicating areas with greater than six mass percent bitumen, from Township 68 - 104, Range 2 West of the 4th Meridian to Range 4 West of the 5th Meridian. Contour interval is 10 m. Pleistocene erosional edge shown by the bold line in the upper right corner of the map (from Wightman *el al.*, 1995).

Fort MacKay Outcrops Stop 15 and Stop 16

Access to the outcrops around Fort MacKay is via roadways, trails and creek/river courses. Two outcrop sections will be visited, including the Amphitheatre MacKay River Section (Stop 15) and the Beaver River Sandstone Quarry (Stop 16).

Stop 15. Amphitheatre MacKay River Section (Figures 15.7 and 15.8)

Access (Figure 15.7): Drive north of Fort McMurray on Highway 63, being sure to gas up in Fort McMurray before leaving town. Turn northwest (left) from Highway 63 onto the Fort MacKay access road, marked by a road sign, just north of the highway bridge over the Beaver River. Continue on the access road to Fort MacKay, going through town to the north end where there is a fork in the road. Turn left and drive along the dirt road until you reach a fork (the right fork goes to the dump). Take the left fork along the MacKay River. Stop approximately 0.5 – 0.75 km from the fork to the dump. Stop and acces a trail to the west and walk for 5 minutes to the cutbank overview of the section at the end of the trail. Easier access down to the base of the outcrop is to the south (left) down a prominent spur that marks the downstream end of the main Amphitheatre outcrop.

At the very base of the Amphitheatre Section along the MacKay River is a thick succession of poorly exposed organic shaly siltstone and coaly siltstone/shale that occurs within a paleokarst low along the pre-Cretaceous unconformity. The overlying contact with the more typical coarse grained channel facies of the Lower McMurray Formation is covered. At the northern end of the outcrop there is a thin coarse-grained pebbly sandstone, that shows trough cross bedding, and probably represented the Lower McMurray channel facies association. This exposure is often covered, depending upon the degree of recent slumping along the exposure. Most of the Amphitheatre section at the north end of the outcrop exposes dominantly fine grained sand, with high angle planar tabular, trough and rippled cross bedding structures and bioturbation features. *Cylindrichnus* burrows, both in place and as resedimented mudstone intraclasts, are common. Most of the outcrop exposure is interpreted as part of the Upper McMurray estuarine channel system, with less common lateral accretion estuarine point bar deposits at the base and top of the channel sands. Rare resedimented coaly detritus, as coalified and mummified stems and logs, occur about half way upsection, but mainly within the inaccessible cliff faces.

Capping the estuarine sands is a thick mainly covered interval, the float of which displays mainly interbedded sand and mudstone, with intense bioturbation consisting of mainly *Cylindrichnus* and *Teichichnus* trace fossils. Where exposed and accessible, this dominantly covered interbedded and bioturbated fine grained interval, is overlain by gray, fine grained bioturbated sands that show parallel lamination, with rare ripple structures, and minor iron-cementation associated with coaly detritus. The bedding style of this uppermost unit is very even, and combined with the degree of bioturbation, the amount of interbedded fines, is indicative of a vertical accretion abandoned channel fill deposit. This vertical accretion fill is unconformably overlain (scoured and/or glacially-thrusted) by Pleistocene tan quartz sand and rooted brown soil horizons, averaging about 0.5 m thick.

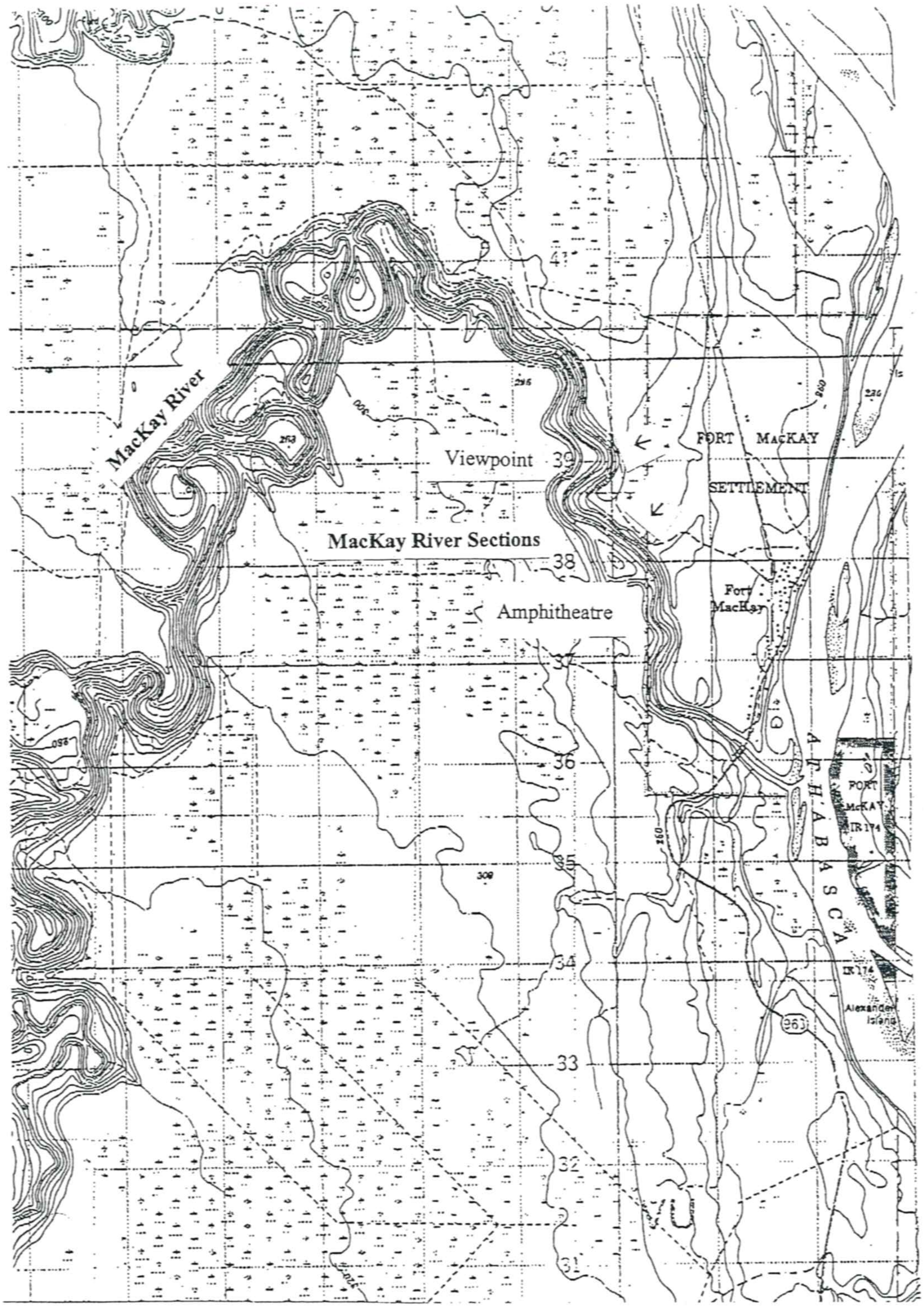

Figure 15.7 Map showing access to the MacKay River outcrops near the Fort MacKay First Nation Settlement.

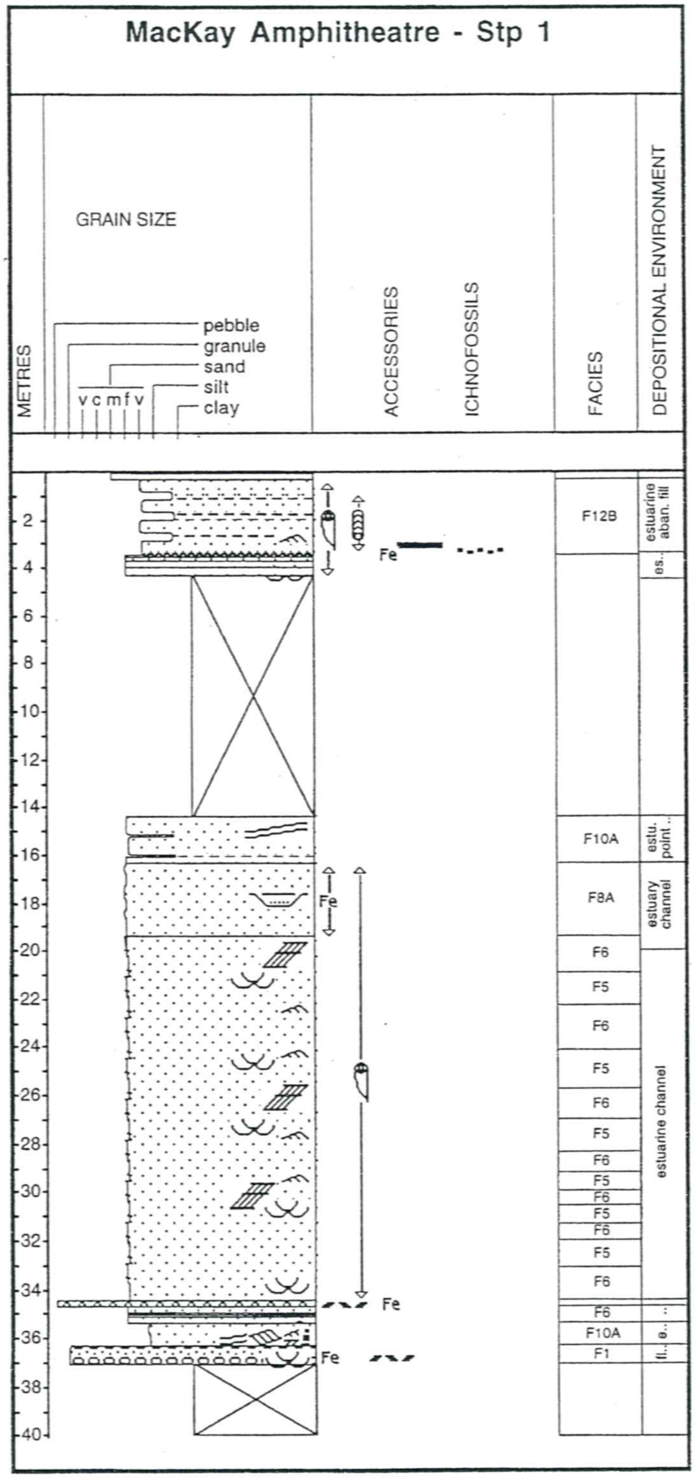

Figure 15.8 Measured stratigraphic section of the Mackay Amphitheatre #1 Section (Stop19). Facies Designations as listed in Table 15.1. Vertical scale bars are each 1 m in height. (UTM 0460250E, 6338250N).

STOP 16 – Beaver River Sandstone Quarry F. Hein

The Beaver River sandstone quarry is located approximately 2 km upstream from the mouth of Beaver River, at its confluence with the Athabasca River, in a small abandoned quarry site along Highway 63 (Figure 16.0).

Access from Fort MacKay: Travel back from the Amphitheatre Section through Fort MacKay to Highway 63 going south. About 0.5 km south of the intersection between the Fort MacKay access road and Highway 63, just north of the bridge over Beaver River, is a small dirt track into the woods on the east (left) side of the highway. Turn onto the dirt track and follow to a small man-made quarry-pond. This quarry exposes the Beaver River Sandstone.

Access from Fort McMurray: Travel north on Highway 63 from Fort McMurray to about 0.5 km south of the access road turnoff to Fort MacKay, just north of the highway bridge over the Beaver River. A small dirt track is located on the east (right) side of the highway. Turn onto the dirt track and follow to the end of the track at a small abandoned quarry. This quarry exposes the Beaver River Sandstone.

Along the stripped-cutbank of the abandoned quarry and at the northern edge of the quarry site are small, low and isolated outcrops of the 'Beaver River Sandstone' (Figure 16.1), a quartz cemented unit within the Lower McMurray Formation. On bedding plane top surfaces and in cross section can be seen as sideritized root traces, some of which are up to 1 cm in diameter. Abundant communited organic detritus occurs throughout the sandstone, and isolated loose organic rubble, including fossil stems and branches and coaly debris, are found as float in the area. Limited palynological dating was done on a coaly fragment from the sandstone, that yielded a modest terrestrial assemblange of palynomorphs that appear to be Aptian-Cenomanian in age.

The quartz cement makes the sandstone distinct lithologically from the other more typically uncemented McMurray Formation sandstones. The quarry section is along strike with weathered carbonate paleo-highs exposed as cutbanks along the Beaver River and as small outcrops along Highway 63. The interpretation is that the cemented quartz sandstone of the Lower McMurray Formation was within a paleolow karst feature at the time of cementation, probably associated with quartz-saturated connate waters. A number of similar quartz-cemented units within the Lower McMurray Formation have also been encountered in subsurface cores from the surrounding area. Quite commonly siderization and siderite cementation is also associated with the quartz cementation.

Historically the quartz-cemented sandstone was quarried at this site by First Nations people (Fenton and Ives, 1982, 1990; Ives and Fenton, 1982). Diagenesis of the Beaver River Sandstone has been examined by Brian Tsang as part of his M.Sc. thesis work at the Department of Geology and Geophysics, The University of Calgary.

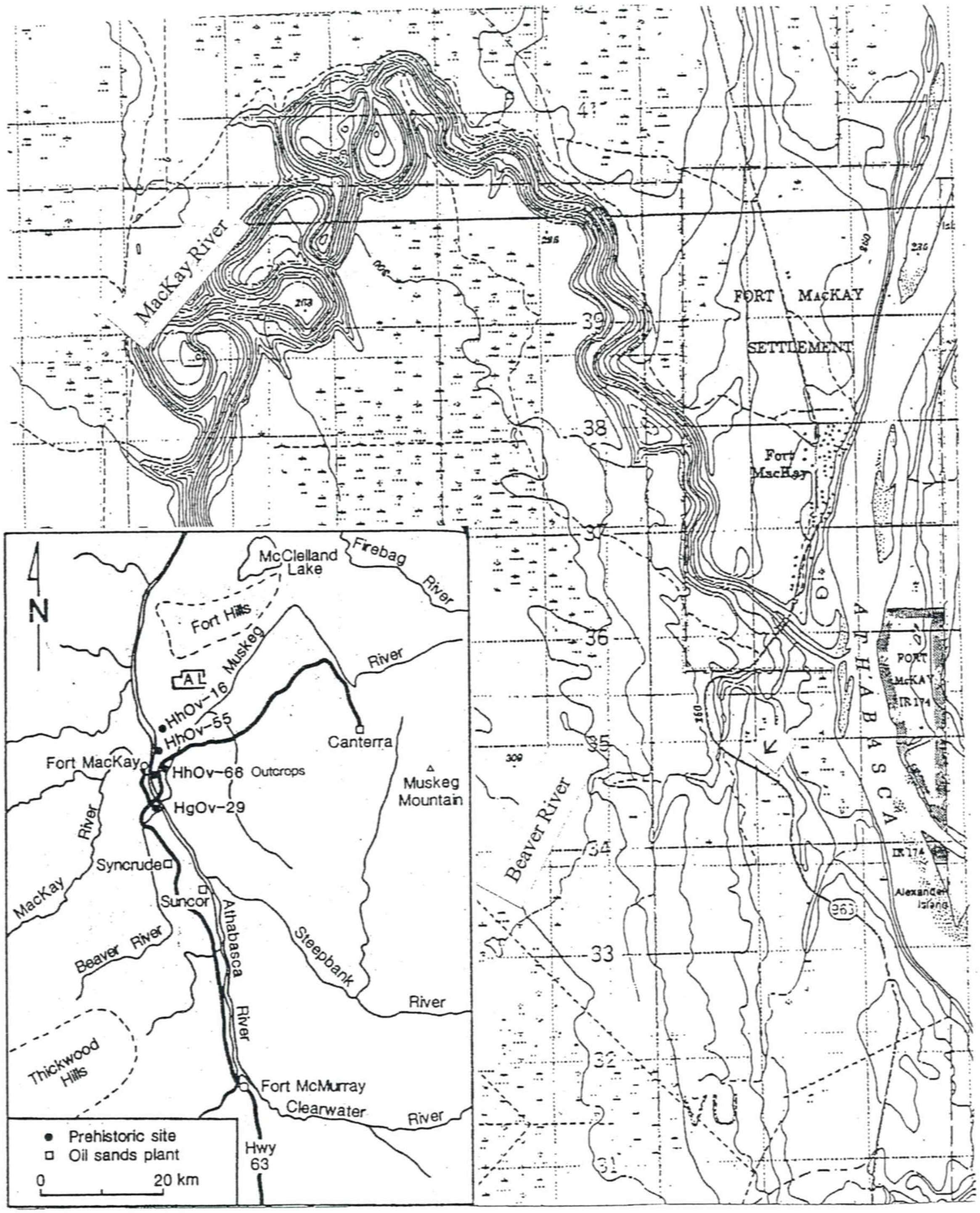

Figure 16.0 Map showing access to the Beaver River Sandstone exposure near the Fort MacKay First Nations Settlement, inset map shows the location of other perhistoric archeological sites associated with Beaver River Sandstone (HhOV-16, -55, -66, -29) in the area (inset map from Fenton and Ives, 1982, 1990; Ives and Fenton,

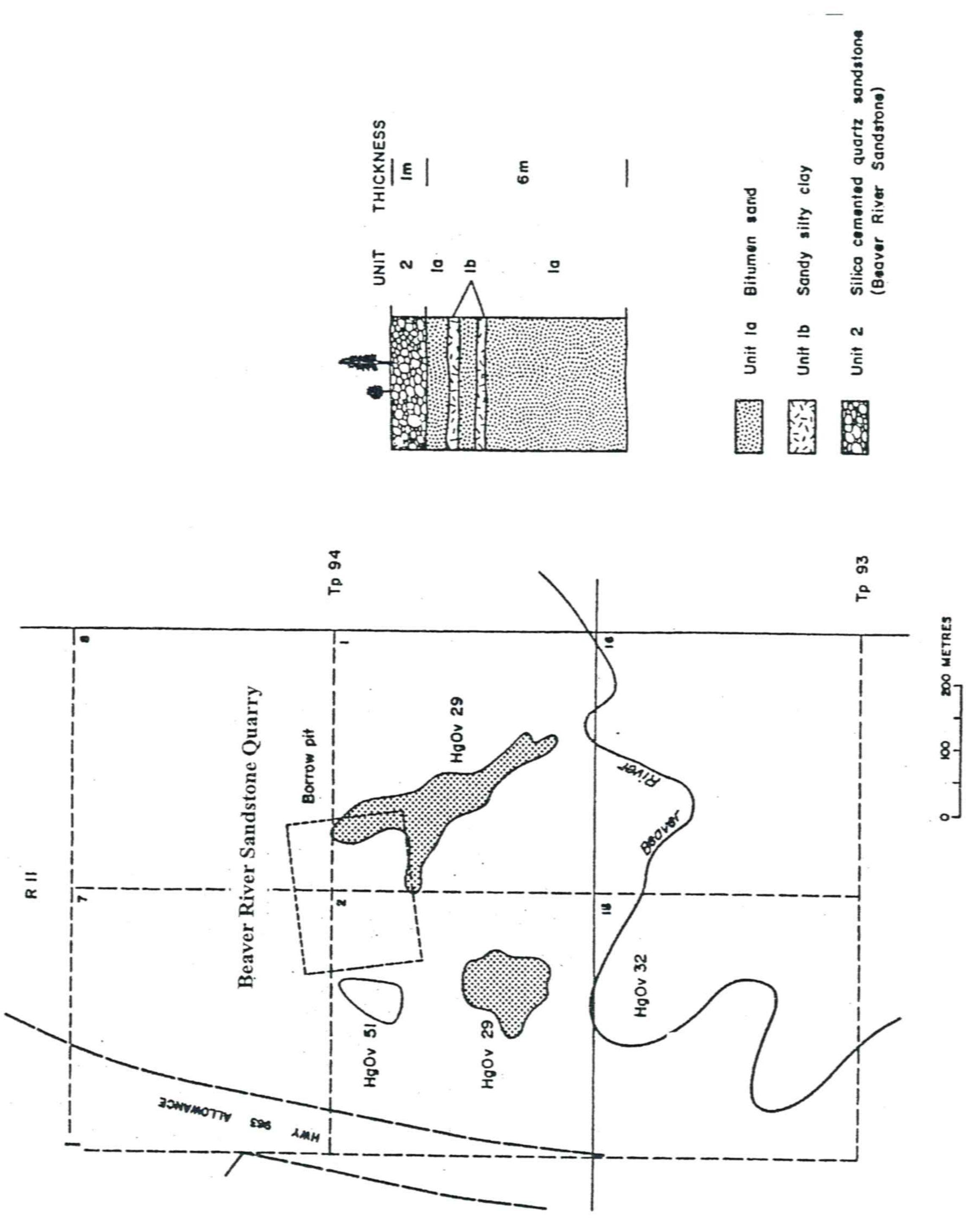

Figure 16.1 Map showing the Beaver River Quarry (HgOv-29) and the borrow pit in which the Beaver River Sandstone is exposed; geologic section at the Beaver River Quarry borrow pit (from Fenton and Ives, 1982).

Access to the outcrops around the city of Fort McMurray is via roadways, trails and creek/river courses. Two outcrop sectons will be visited, including the Saline Creek Sections (Stop 17) and the Hangingstone River Sections (Stop 18) (Figures 17.0 and 18.0).

Saline Creek Sections

This section is located approximately 0.5 km upstream from the mouth of Saline Creek, at its confluence with the Clearwater River (Figures 15.3 and 17.0).

Access to the Saline Creek Section: Drive north on Highway 63 (Memorial Drive/ Saskatchewan Trail) from the southern city limits of Fort McMurray, drive past the Oil Sands Interpretive Centre and the Tourist Information Centre (Port of Entry). Take the next right (east turn) onto Gregoire Drive. Park near the intersection of Gregoire Drive and Highway 63. Walk about 15 minutes downhill along the bike trail, cutting over east to Saline Creek once you see the outcrops to the south near a major culvert (Figure 16.0).

Along Saline Creek medium-grained, fluvial-estuarine sediment of the Upper McMurray Formation (formerly called Middle McMurray, cf. Hein *et al.*, in prep.) is well exposed as a series of small cutbank sections, ranging from 8 metres to > 30 metres high. The thick estuarine sediment shows abundant cross bedding, including trough, high angle planar-tabular, planar-tangential and rippled units (Figures 16.1 to 16.3). Rhythmic tidal couplet cross bedding was noted as a secondary component to the cross-bedded dominated facies. Paleoflow directions on the trough cross beds are to the northeast; to the east-northeast for planar tabular cross beds; and dominantly to the north in rippled sands. Mudstone interbeds and lenses are extremely rare. Locally intraclast mudstone breccia beds, ranging from 3-5 cm thick, occur. Mud-lined *Cylindrichnus* burrows are rare, and are mainly seen as resedimented clasts within the mudstone breccia beds. The dominance of high-energy flow features, the relatively uniform paleoflow trends, along with a secondary tidal influence, indicate that these sediments were deposited within high-energy estuarine channels, as bedload dominanted systems.

At the very top of the outcrops along Saline Creek is exposed a thin (< 1 m), bioturbated, greenish caste sandstone. This is the glauconitic Wabiskaw C unit (Wabiskaw Member, Clearwater Formation) that unconformably overlies the McMurray Formation in this area.

Note the abundance of bitumen staining, the general absence of organics and ironstone concretions, and the predominance of high energy cross bedding features at these outcrops. At the base, in the upstream outcrop section, the sediment was originally water bearing, overlain by the thicker oil-bearing Upper McMurray. This would represent an original water lag in the lower portion of the Upper McMurray succession. This bottom water may pose potential problems for SAGD production from the lower portions of the Upper McMurray unit.

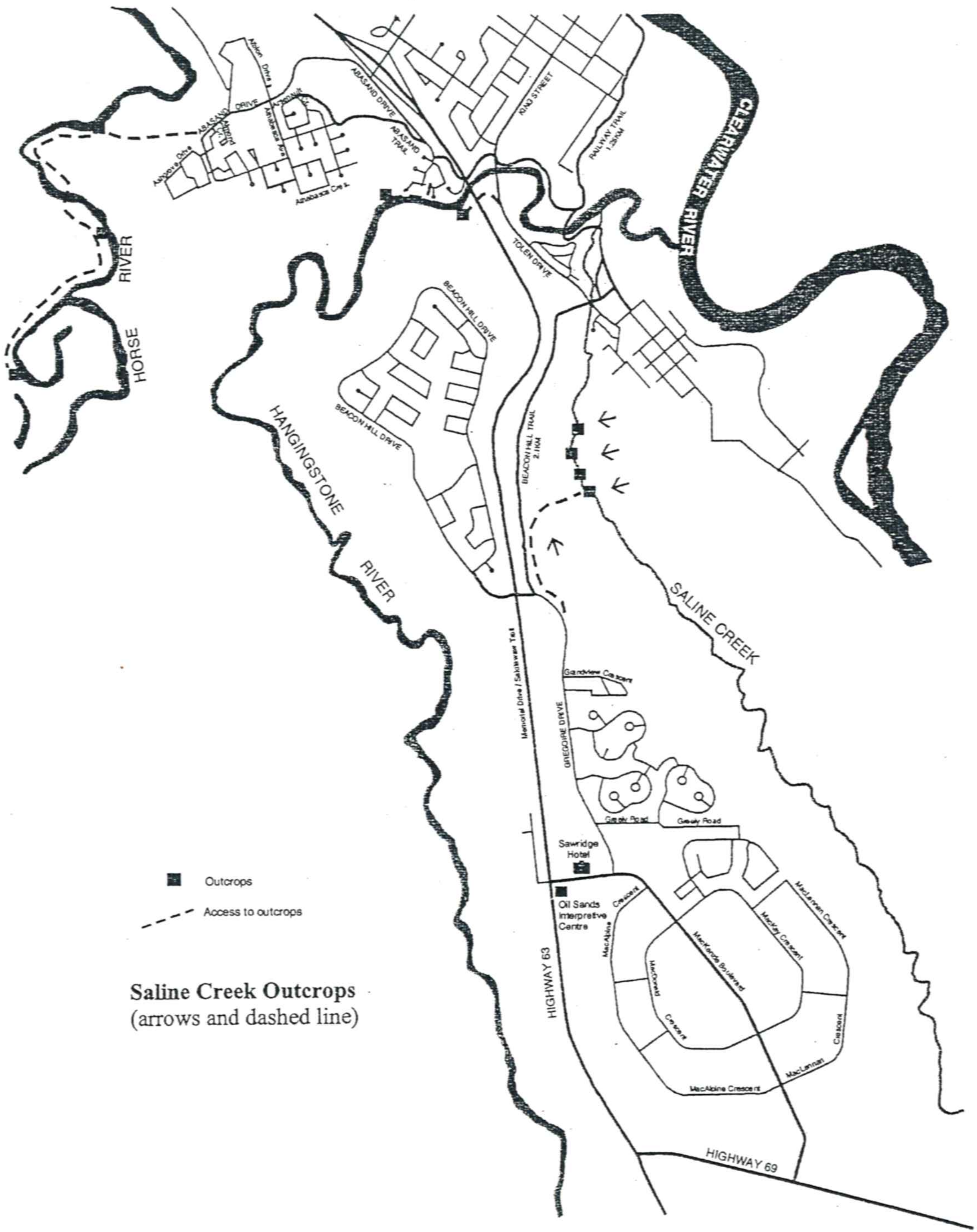

Figure 17.0 Map showing access to the Saline Creek outcrops in the town of Fort McMurray.

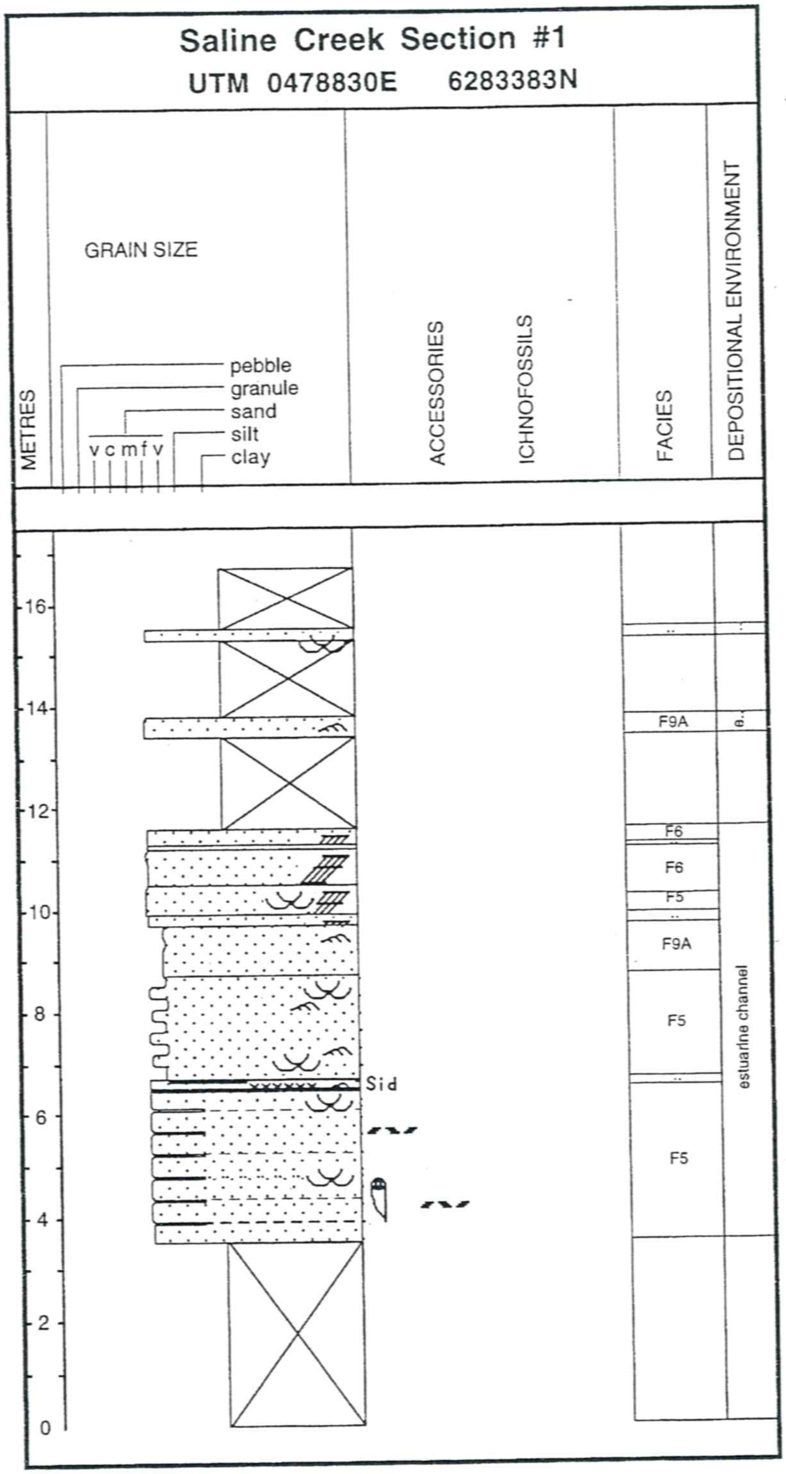

Figure 17.1 Measured stratigraphic section of the Saline Creek Section #1 (Stop17). Facies Designations as listed in Table 15.1. Vertical scale bars are each 1 m in height. (UTM0478830E, 6283383N).

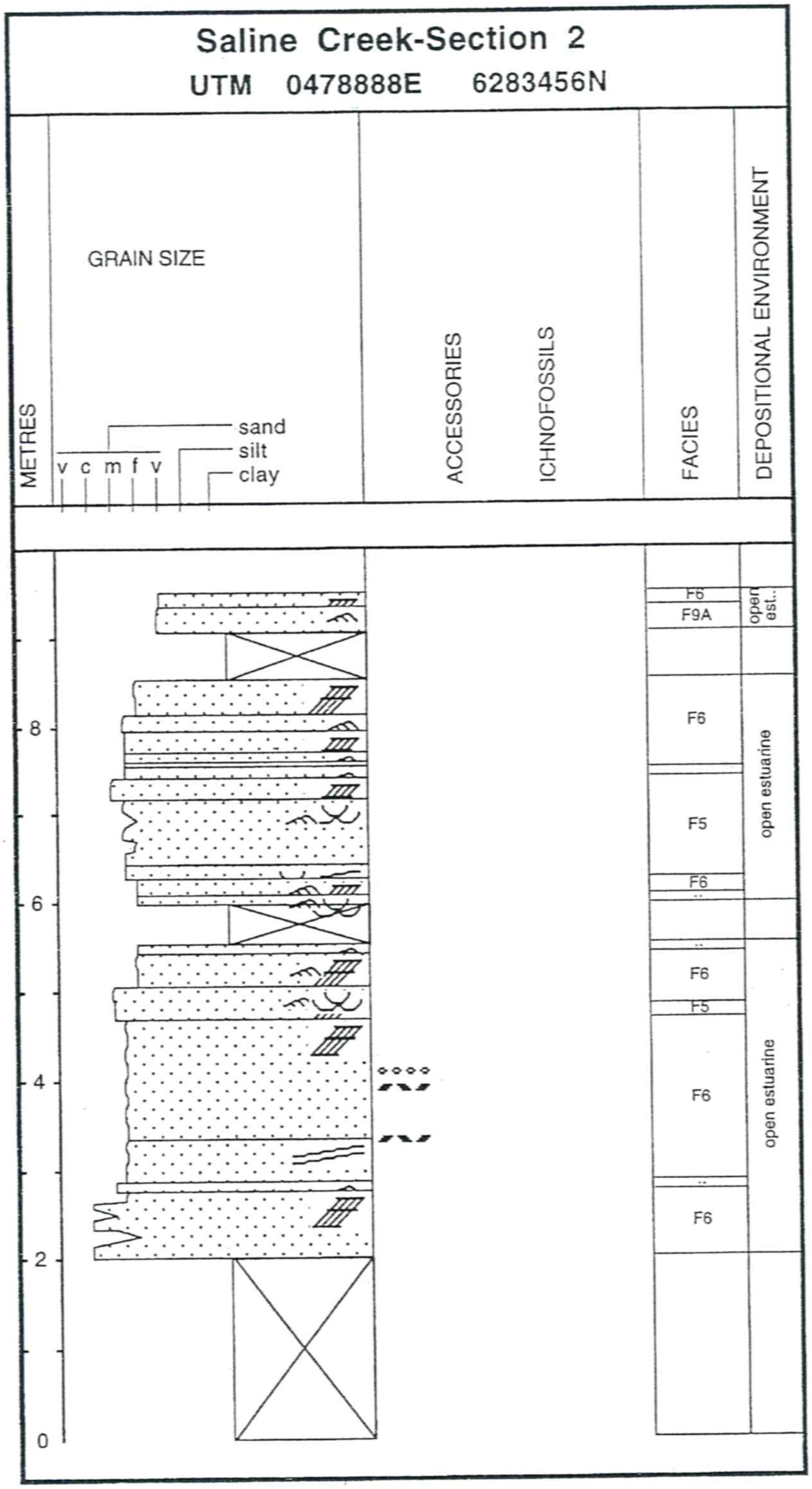

Figure 17.2 Measured stratigraphic section of the Saline Creek Section #2 (Stop17). Facies Designations as listed in Table 15.1. Vertical scale bars are each 1 m in height. (UTM0478888E,6283456N).

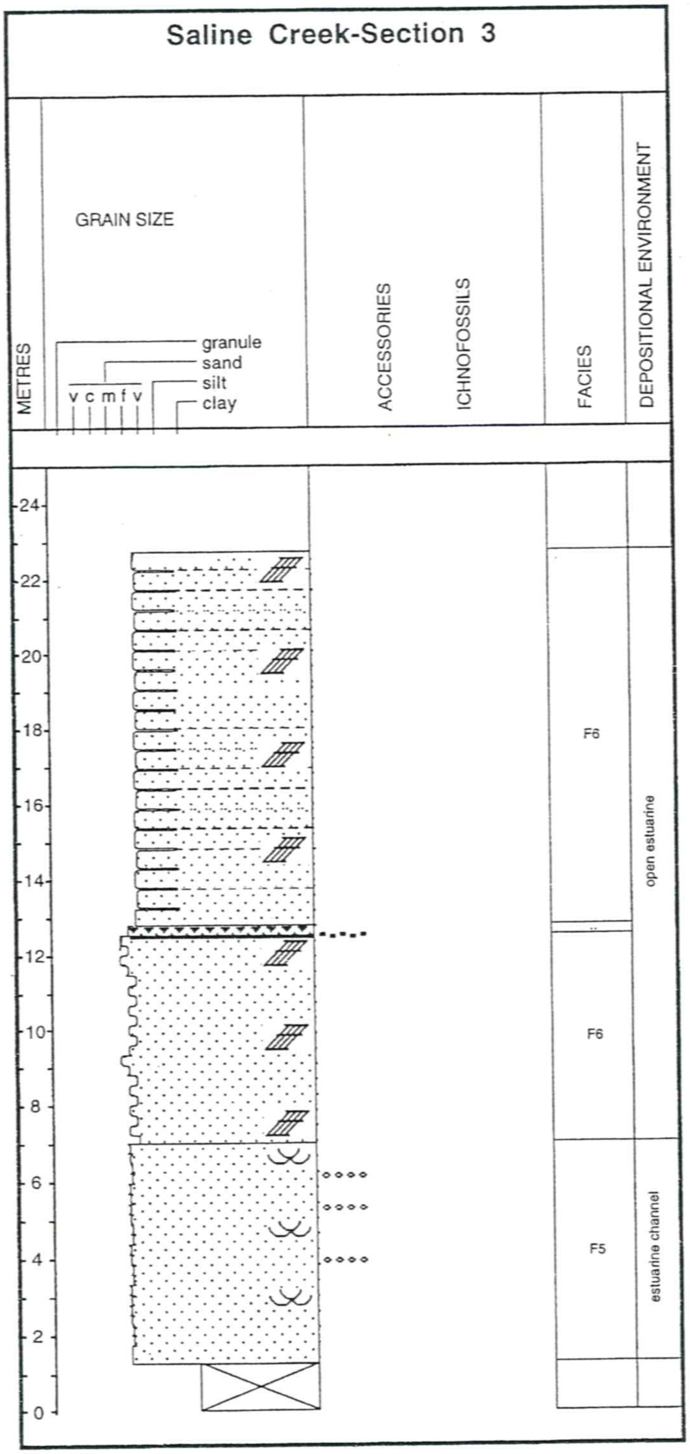

Figure 17.3 Measured stratigraphic section of the Saline Creek Section #3 (Stop17). Facies Designations as listed in Table 15.1. Vertical scale bars are each 1 m in height. (UTM 0478838E, 62834656N).

This section is located approximately 2.0 km upstream from the mouth of the Hangingstone River, at its confluence with the Clearwater River (Figure 15.3).

Access to the Hangingstone River Section (Figure 18.0): Drive north on Highway 63 (Memorial Drive/ Saskatchewan Trail) from the southern city limits of Fort McMurray, drive past the Oil Sands Interpretive Centre and the Tourist Information Centre (Port of Entry). Take the third right (east turn) onto Hospital Street, then an immediate left onto a bridge over Highway 63 (Memorial Drive/ Saskatchewan Trail). Turn left (southeast) onto Abasand Drive and continue into the Grayling Terrace Sudbivision. Park at a cul de sac near the river (either Graham Place or Gardiner Place). At the end of each cul de sac is a public access gate to the trail along the north side of the Hangingstone River. Walk upstream (west) along the trail for about 5 minutes until the first outcrop on the north bank is reached.

In this thick outcrop section, about 50 metres high, is exposed the estuarine sediment of the Upper McMurray Formation (formerly called Middle McMurray, cf. Hein *et al.*, in prep.) (Figure 18.1). The thick estuarine succession at this outcrop starts with a fine-grained mudstone abandoned fill unit, that is mainly slumped at the base of the outcrop. This abandoned-channel fill mudstone is overlain by sediment with abundant cross bedding, including trough, high angle planar-tabular, planar-tangential, low-angle sandy and muddy inclined units, interpreted as lateral accretion cross bedding that formed on the edges of estuarine point bars. Mudstone interbeds and lenses are common, with an increase in frequency and thickness going upsection. Concommitant with this increase in mudstones, is also an increase in bioturbation intensity, with the most common types being *Cylindrichnus* (cone-shaped) and horizontal *Planolites,* with rare vertical *Skolithos.* Thin, indurated (siderite-cemented), coquina beds of gastropod shells are located in the middle of the section. These are interpreted as possible storm-surge channel deposits.

At the top of the outcrop is exposed approximately 4.5 metres of glauconitic, bioturbated, well sorted sand. This is the Wabiskaw C unit (Wabiskaw Member, Clearwater Formation) that unconformably overlies the McMurray Formation in this area. The Wabiskaw C is, in turn, unconformably overlain by Quaternary-age sediment.

Note the abundance of bitumen staining, the abundance of mudstone abandoned-channel fill deposits at the base of the succession, the abundance of organics, iron-stone concretions and cemented zones near the upper contact with the Wabiskaw, and the generally unconsolidated nature to the sediment at this outcrop. During low-water conditions, one can access the opposite, north facing, cutbank near the bridge across the Hangingstone River. Here a similar succession of mudstone abandoned channel-fill deposits is overlain by thick esturaine channel sediment, capped by a thin glauconitic Wabiskaw C unit (Figure 18.2).

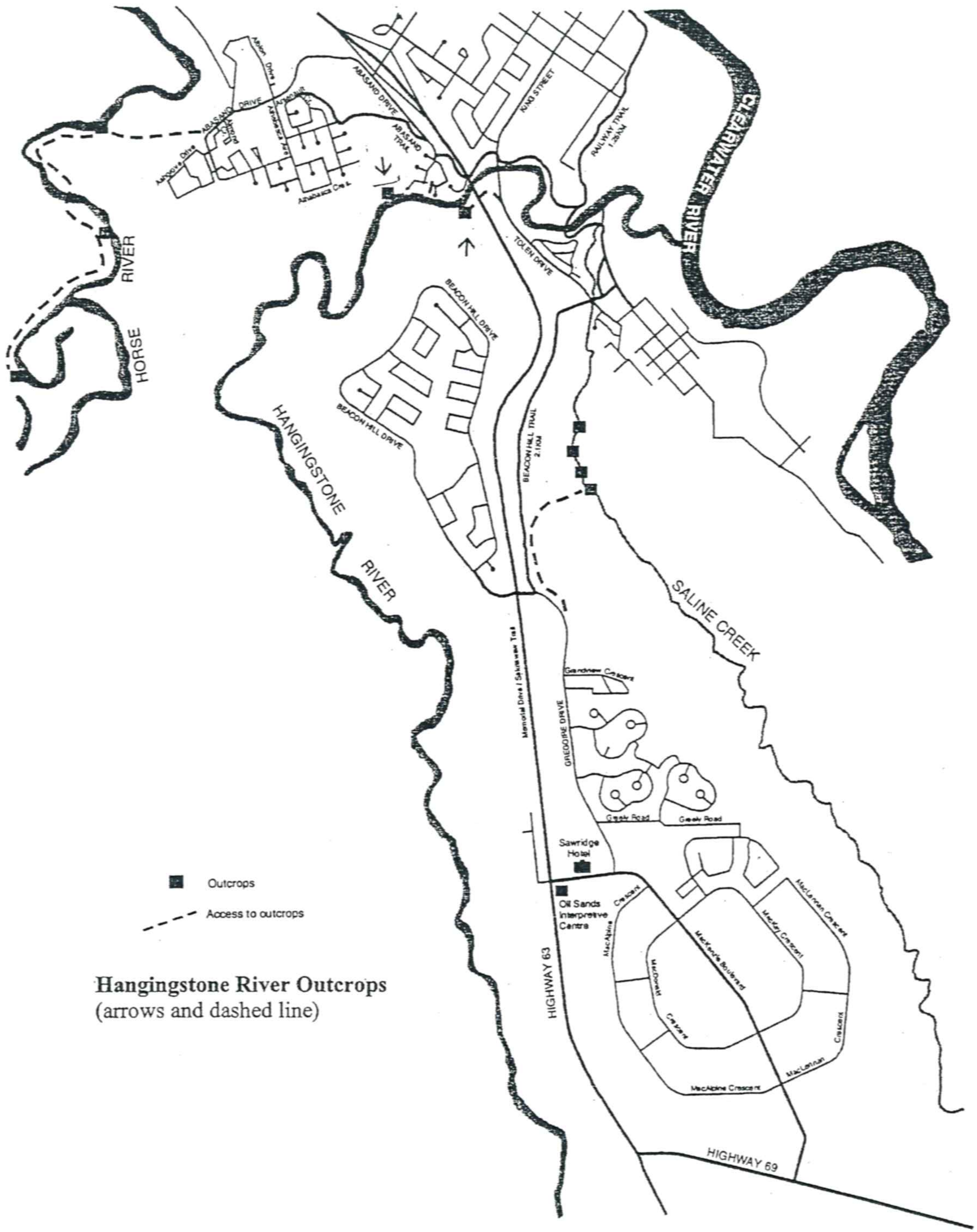

Figure 18.0 Map showing access to the Hangingstone River outcrops in the town of Fort McMurray.

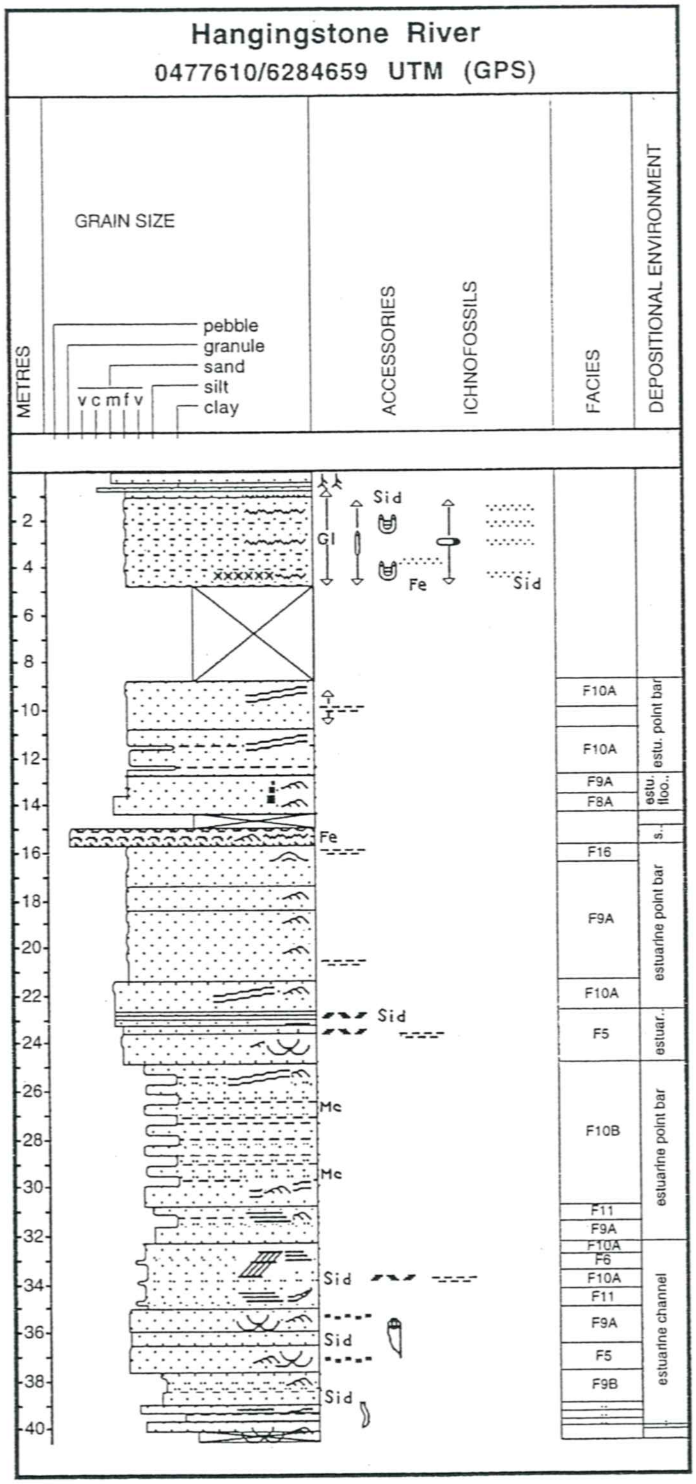

Figure 18.1 Measured stratigraphic section of the Hangingstone River Section (Stop18). Facies Designations as listed in Table 15.1. Vertical scale bars are each 1 m in height. (UTM 0477610E, 6284659N).

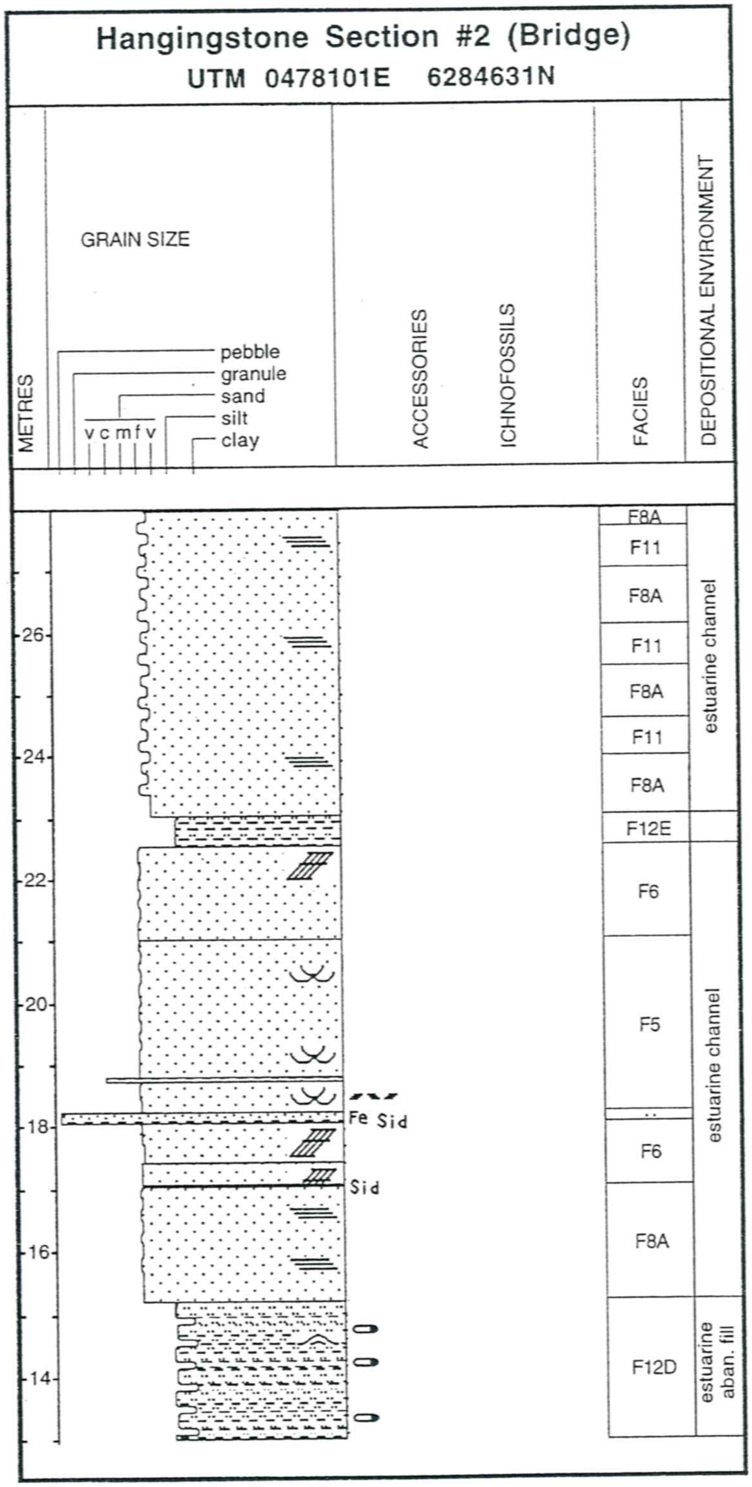

Figure 18.2 Measured stratigraphic section of the Hangingstone Section #2 (Bridge) (Stop18). Facies Designations as listed in Table 15.1. Vertical scale bars are each 1 m in height. (UTM 0478101E, 6284631N).

Access to the Athabasca River outcrops is via jetboat from the Snye Park Landing in Fort McMurray. Three outcrop sectons will be visited, including the Athabasca River Downstream Section (Stop 19A), the Tar Island Section (Stop 19B), and the Type Section (Stop 19C).

Stop 19A. Athabasca River Downstream Section

This section is located approximately 15 km downstream from the confluence of the Athabasca and Clearwater rivers on the east bank of the Athabasca River near the mouth of Donald Creek (Figure 15.3). In this small outcrop section, about 5 metres high, some of the oldest Lower Cretaceous sediment that unconformably overlies the Devonian limestone in the area is exposed. Here a mainly slumped section of paleosol/marly calcareous mudstone deposit with interbedded carbonaceous shales and minor fluvial sandstones occupies a paleotopographic low on the pre-Cretaceous unconformity. Although the section is Cretaceous in age (based on palynomorphs), this unit is interpreted as pre-McMurray-age sediment.

Note the general absence of bitumen staining, the abundance of organics, and ironstone concretions, and the generally unconsolidated nature to the sediment. Originally this unit was probably water bearing, and since exposure along the Athabasca Valley has become further eroded and slumped along the bank. Initial palinspastic reconstructions suggest that this location is typical of those areas that were originally paleotopographic lows along the karstic pre-Cretaceous unconformity. One hypothesis that accounts for the lack of bitumen staining in this part of the section is that the original medium to heavy crude was emplaced laterally along-strike at a stratigraphic interval higher than that represented by the marl section. The interpretation is that the relict original formation waters were never replaced by hydrocarbons this low in the stratigraphic succession due to isolation and lack of vertical and lateral connectivity with the overlying more porous reservoirs within the McMurray Formation.

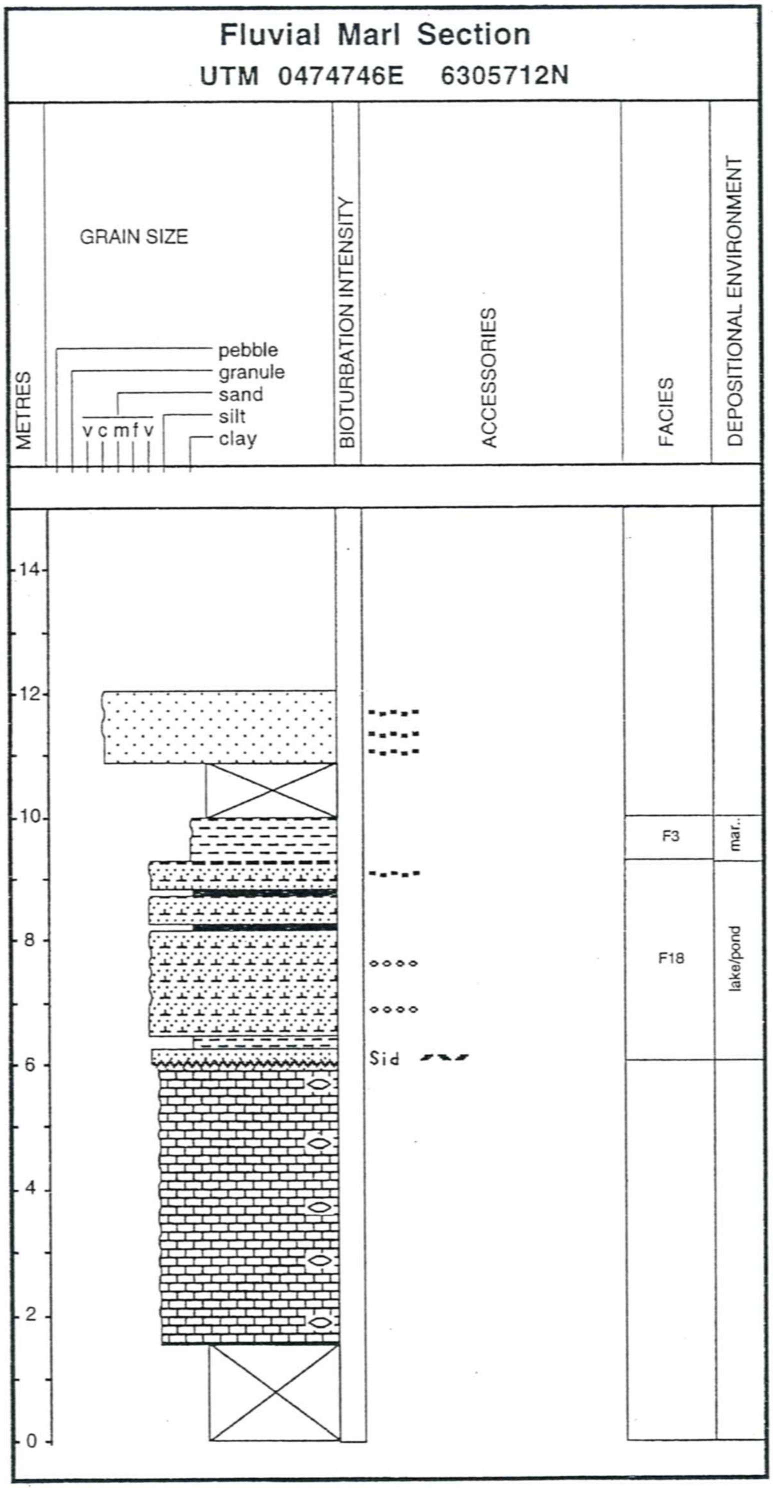

Figure 19A.1 Measured stratigraphic section of the Fluvial Marl Section, Athabasca River Downstream Section (Stop 1). Facies Designations as listed in Table 15.1. Vertical scale bars are each 1 m in height. (UTM 0474746E, 6305712N).

Stop 19B. The Tar Island Section

This section is located approximately 0.5 km upstream from the northern end of Tar Island, near the tailings from the Suncor Mine, along the western bank of the Athabasca River (Figure 15.3). The outcrop, about 9 metres high, fluvial sediments of the Lower McMurray Formation are exposed at the base, unconformably overlain by estuarine sediments of the Upper McMurray Formation (formerly called Middle McMurray, cf. Hein *et al.*, in prep.). Most notable in the section are the common occurrences of sideritized intraclasts within the Lower McMurray fluvial channel sand deposits, and a prominent conglomerate, up to 1-metre thick, along the unconformable contact between the Lower and Upper McMurray. This conglomerate starts as a thin-pebble thick layer at the downstream end of the outcrop (or is absent), upstream reaching its maximum at the upstream end of the outcrop. The conglomerate is poorly sorted, in comparison to the underlying fluvial succession in the Lower McMurray. The clasts within the conglomerate tend to be fairly well rounded, and the lithologies are generally more resistant rock types, such as vein-quartz and quartz-pebbles. This unit is interpreted as representing a transgressive lag deposit associated with the transgressive surface of erosion, marked by the unconformity, and is related to the onset of marine flooding in the area. This marine flooding emplaced the fluvial esturarine deposits of the Upper McMurray above the fluvial lowstand deposits of the Lower McMurray.

Note the general absence of bitumen staining, the abundance of ironstone concretions and iron-cement, and the generally unconsolidated nature to the sediment at the downstream end of the outcrop. About half-way upstream along the outcrop exposure there is a prominent, discordant contact between the unconsolidated white sands and the bitumen-bearing oil sands. Associated with this discordant contact is an apparent "roll front" as shown in the siderite-cemented unit. It is possible that this outcrop marks the original oil-water contact within the McMurray sediment, prior to degradation of the oil to bitumen. As with the marl section, one hypothesis that might explain a lack of bitumen staining at the base of the section below the sideritized roll-front, is that the original medium to heavy crude was emplaced laterally along-strike at a stratigraphic interval higher than that represented by sideritized section. The sideritization may have occurred early in the history of the McMurray succession, and may have been the result of cementation associated with either connate- or ground-water conditions. These orginal connate or ground waters were never replaced by hydrocarbons this low in the stratigraphic succession due to isolation and lack of vertical and lateral connectivity (caused by sideritization) with the overlying more porous reservoirs within the McMurray Formation.

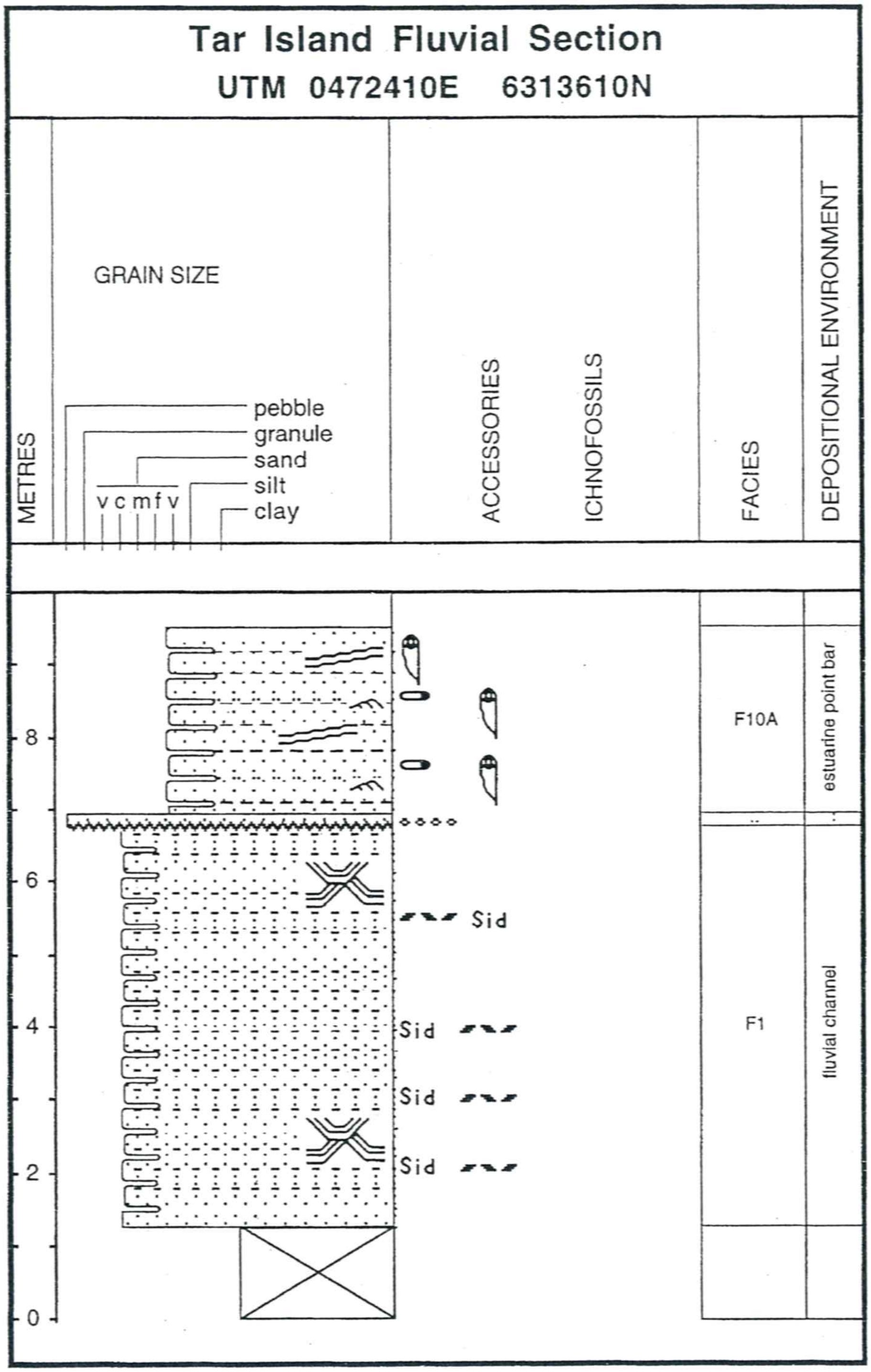

Figure 19B.1 Measured stratigraphic section of the Tar Island Fluvial Section, Athabasca River Section (Stop 2). Facies Designations as listed in Table 15.1. Vertical scale bars are each 1 m in height. (UTM 0472410E, 6313610N).

Stop 19C. McMurray Type Section

This section is located approximately 5 km downstream from the confluence of the Athabasca and Clearwater rivers on the east bank of the Athabasca River near the mouth of Clarke Creek (Figure 15.3). In this thick outcrop section, about 50 metres high, a thin remnant (2 metres thick) of the Lower McMurray fluvial sandstone occurs at the base. The Lower McMurray is recognized but its low amount of bitumen staining and its relatively unconsolidated and slumped appearance. Unconformably overlying this unit is the fluvial-estuarine sediment of the Upper McMurray Formation (formerly called Middle McMurray, cf. Hein *et al.*, in prep.). The thick, fluvial- estuarine sediment shows abundant cross bedding, including trough, high angle planar-tabular, planar-tangential and rippled units. Mudstone interbeds and lenses are common, with an increase in frequency and thickness going upsection. Concommitant with this increase in mudstones, there is also an increase in bioturbation intensity, with the most common types being *Cylindrichnus* (cone-shaped) and horizontal *Planolites,* with rare vertical *Skolithos* (Figs. 19C.2 19C.3, 19C.4). These trends indicate a more marine trend going from fluvial-dominated at the base to estuarine-dominanted at the top.

At the very top of the outcrop is exposed a thin (< 1 m), bioturbated, black, silty mudstone that is the Wabiskaw D unit (Wabiskaw Member, Clearwater Formation), that unconformably overlies the McMurray Formation in this area.

Note the abundance of bitumen staining, the abundance of organics, iron-stone concretions, and the generally unconsolidated nature to the sediment at this outcrop. At the base, in the fluvial Lower McMurray, the sediment was originally water-bearing, overlain by the thick oil-bearing Upper McMurray. Through time the oil in the Upper McMurray degraded to the bitumen, that now serves as the cement to the sand. Once the bitumen is removed, the sand is unconsolidated. The topmost Wabiskaw D silty shale shows relatively little bioturbation structures at this outcrop, compared to other sites, and may locally serve as a cap rock at the type section.

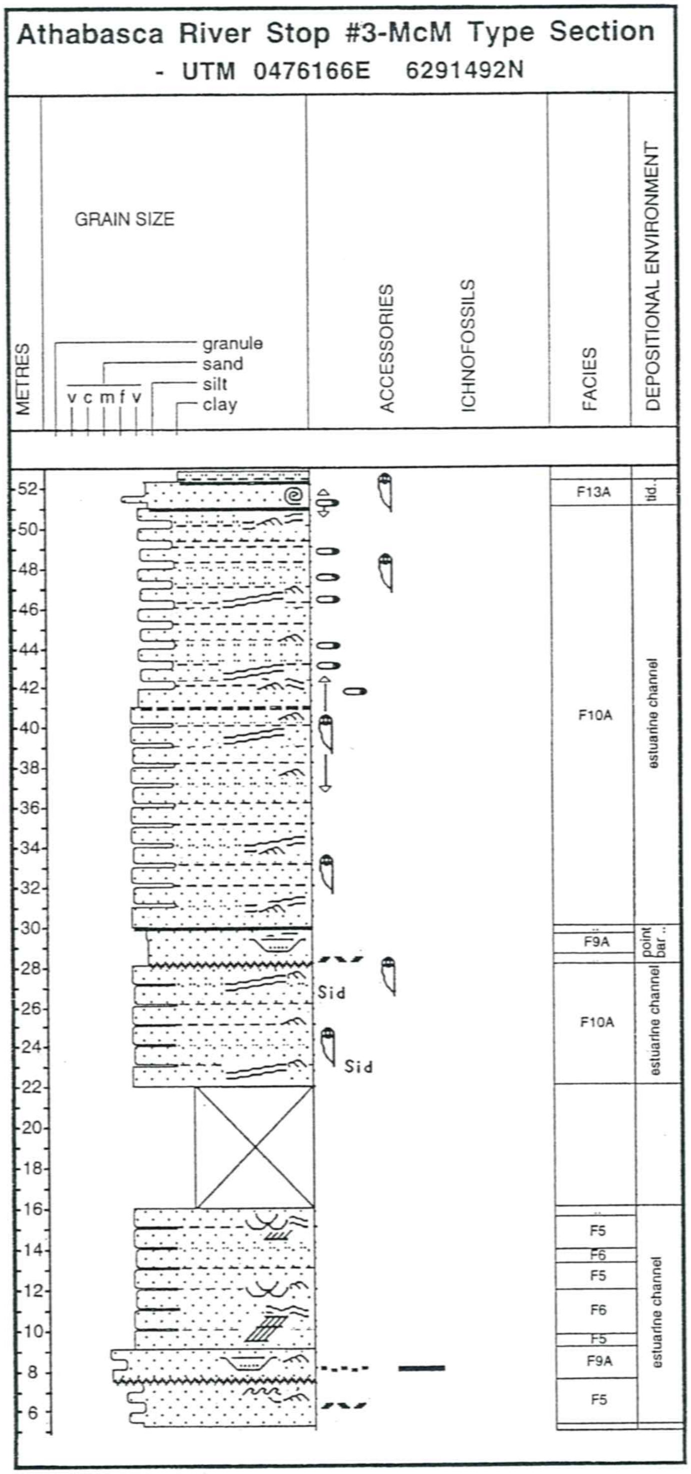

Figure 19C.1 Measured stratigraphic section of the McMurray Type Section, Athabasca River Section (Stop 3). Facies Designations as listed in Table 15.1. Vertical scale bars are each 1 m in height. (UTM 0476166E, 6291492N).

Figure 19C.2 Cone-shaped *Cylindrichnus* burrows within rippled Upper McMurray Formation, Steepbank River outcrop #3. Field of view is approximately 0.3 metres across. Facies 9A.

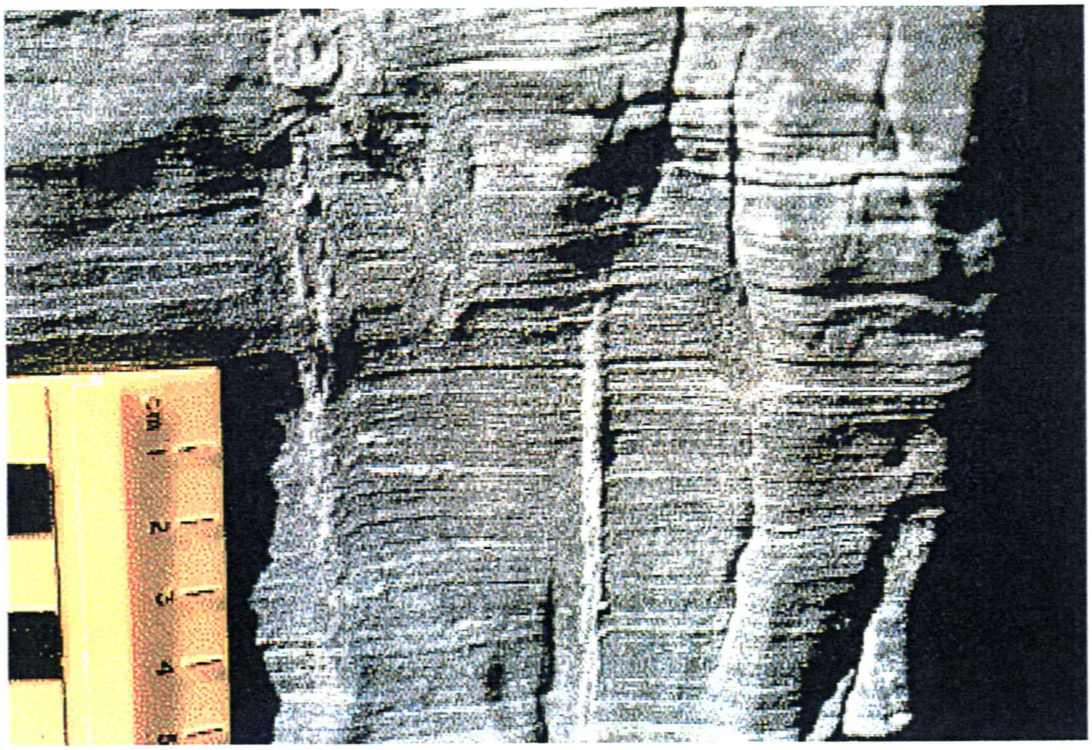

Figure 19C.3 Vertical *Skolithos* in very fine grained sandstone of the Upper McMurray Formation, Viewpoint Section, MacKay River.

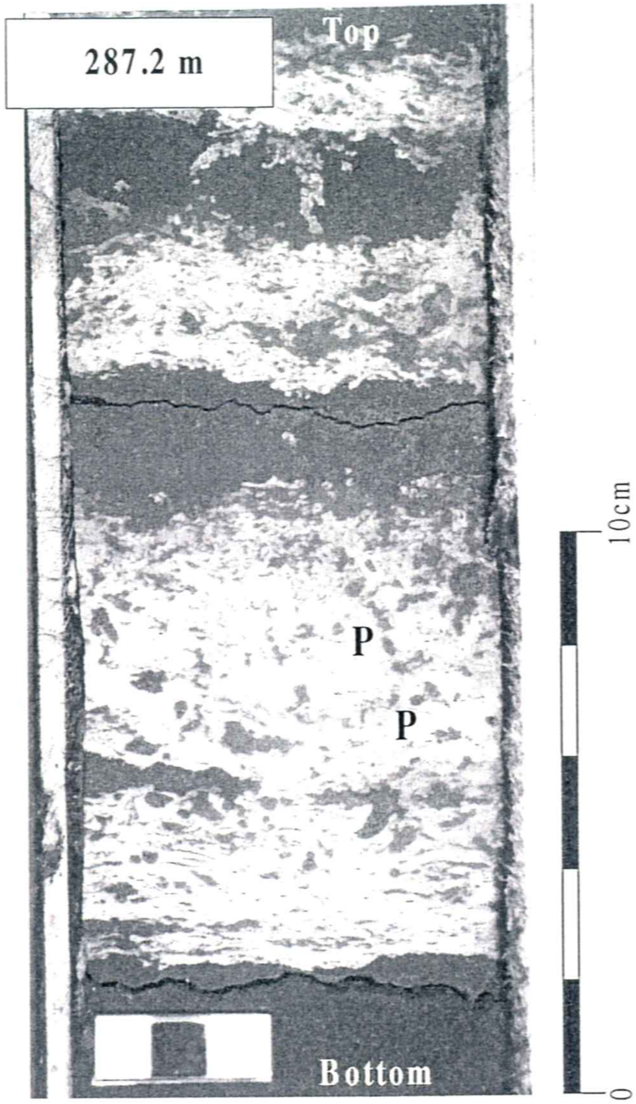

Figure 19C.4 Horizontal *Planolites* burrows within mud-dominated, inclined heterolithic stratification, Upper McMurray Formation. Subsurface core from well 00-00-000-00W4. Facies 10B (see Table 15.1)

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