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GROUNDWATER FLOW, PORE-PRESSURE ANOMALIES AND PETROLEUM ENTRAPMENT, BELLY RIVER FORMATION, WEST-CENTRAL ALBERTA.

BY

KEVIN PRESTON PARKS

A THESIS
SUBMITTED TO THE FACULTY OF GRADUATE STUDIES AND RESEARCH IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE OF MASTER OF SCIENCE.

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Abstract

An investigation of fluid flow in the Belly River Formation was performed in the study area. Groundwater flow in the Belly River Formation is upward and westward. The upward flow is indicated by superhydrostatic vertical pore-pressure gradients. This flow is controlled by the presence of a regionally-extensive pore-pressure sink in the overlying Edmonton Formation.

The pore-pressure sink is generated by fluid-pressure reduction in rock pores in fine-grained strata which elastically expanded following the removal of over 2000 meters of overburden by erosion since the mid-Tertiary. It remains active today because the low permeability of the fine-grained sediments is delaying re-equilibration of pore-pressures to modern conditions. Shales in the Edmonton Formation have higher than expected porosities, supporting the contention that rock-pores have dilated. It is proposed that the westward flow of groundwater is due to a westward increase in strength of the pore-pressure sink.

Anomalous depressions in the water-hydraulic gradient in the lower Belly River Formation are coincident with thick sand lenses. The anomalously low hydraulic heads are the upstream manifestations of fluid-potential field distortions as induced by the presence of highly permeable rock bodies emplaced in a fluid-flow field. The interaction of flow direction, orientation of bedding, choice of map plane and data distribution is responsible for the observed lack of corresponding downstream anomalies. Derived oil-hydraulic heads show depressions in an east-to-west oil hydraulic gradient coincident with the same sand lenses. The rock lenses, sites of actual oil and gas deposits, function as petroleum traps.

The east-to-west flow paths of water and oil are contrary to the west-to-east flow believed to be responsible for regional petroleum migration in the Alberta Basin. This contradiction is resolved if the present flow-system is not the one that existed at the time of regional petroleum migration.

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Special thanks must go to my supervisor, Dr. József Tóth. The things that I have learned from this man go far beyond the bounds of hydrogeology. I will never forget him for our numerous talks on topics of geology and science, our educational system, the state of the economy, politics and the definition of a potable beer, among other things. If I were to take nothing from this place but a broader view of the world and of science's place in it, like that of Dr. Tóth's, my time spent here would still have been worthwhile.

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1. Introduction

1.1 Preface

Hydrogeological studies often demand a holistic approach as many hydrogeological phenomena are best understood when considered in relation to larger scale processes. For example, the fluid pressure in a single pore may be controlled by a regional groundwater flow-system that operates over a volume of thousands of cubic kilometers of a sedimentary basin. In order to understand the controls on fluid pressure in that single pore, it may be necessary to understand the entire flow system.

In other hydrogeological studies a reductionist approach may be more appropriate. This is an approach that seeks to understand a phenomenon of interest by understanding its component parts. An example of the reductionist approach in hydrogeology is the study of groundwater flow to wells. Our understanding of this process is based on mathematical models. These models have been created by reducing the actual physical problem to a set of assumptions and observations that can be described by mathematical language. The equations then derived describe and predict the behaviour of groundwater flowing to wells.

This thesis presents an investigation of the relationships between regional groundwater flow, highly permeable rock bodies and hydrocarbon accumulations in the Upper Cretaceous Belly River Formation of west-central Alberta. The techniques used include those commonly referred to as "hydrodynamics" in the petroleum industry, namely potentiometric-map analysis and study of vertical pore-pressure gradients. This research project was motivated by previous success in applying potentiometric mapping to the problem of exploration for highly permeable lenticular rock bodies (Tóth and Rakhit, 1988).

When intially conceived, the study appeared well-suited to a reductionist approach: observe the regional groundwater flow and hydrocarbon distribution in the chosen study area and examine the geology in sufficient detail to discover its relationship to the flow patterns and the distribution of oil pools. This study was carried out and met with success. Potentiometric-map analysis reveals relationships between hydrocarbon accumulations, regional groundwater-flow and geology, confirming the conclusions of Tóth and Rakhit (1988) and advancing our knowledge of both the underlying relationships between these three parameters and the use of potentiometric maps in exploration for highly permeable rock bodies.

There are, however, several observations made during this research that are contrary to initial expectations. The pore-pressures in the Belly River Formation are subhydrostatic in magnitude. Regional groundwater flow is from east to west; it was expected that it would be from west to east. Theoretical analysis of oil motion in the groundwater flow-field showed it would also move east to west; conventional petroleum geological wisdom stipulates that, in the Alberta Basin, hydrocarbons were derived from source rocks in the western part of the basin and migrated from west to east. The contradictions demanded further investigation, which required a holistic approach: the phenomena could only be understood in the context of the geological history of the entire Alberta Basin.

For the somewhat philosophical reasons discussed above, this study is divided into two main parts. An explanation is attempted in the first part for the regional occurrence of subhydrostatic pore-pressures in the Belly River Formation. The second part deals with a hydrodynamic analysis of an oil and gas pool in the Belly River Formation. The first part is holistic in approach, the second part reductionist. In the general summary, these observations and conclusions will be integrated into a model of regional groundwater flow in the Belly River Formation in the study area and its control on hydrocarbon accumulations in highly permeable rock bodies.

1.2 Thesis Objectives

The primary objective of this thesis is to show, using potentiometric maps, that there are field-demonstrable relationships between regional groundwater flow patterns, highly-permeable rock bodies and petroleum accumulations in the Upper Cretaceous Belly River Formation of west-central Alberta. The relationships between regional groundwater flow-patterns and such rock bodies are expected because mathematical models and field examples (Tóth, 1962; Tóth, 1966; Tóth and Rakhit, 1988) have shown that the presence of highly permeable rock bodies distorts the fluid-potential field in such a way as to focus flow into and through the bodies. Theoretical considerations of this effect (Tóth, 1970) predict that such rock bodies will also be favoured sites for accumulation of migrating hydrocarbons.

A secondary objective of this study is to explain the regional occurrence of subhydrostatic pore-pressures in the Belly River Formation of west-central Alberta. Prior to this study, there has been no detailed examination of their occurrence in this formation.

1.3 References

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2 Subhydrostatic Pore-Pressures in the Belly River Formation, West-central Alberta: Study and Interpretation

2.1 Introduction

Pore-pressures are called "subhydrostatic" if they are smaller than the pressure at the bottom of a column of fresh water which is at rest and the height of which equals the depth below the water table of the point of measure. The presence of subhydrostatic pore-pressures in the Upper Cretaceous Belly River Formation of Alberta is well known to geologists involved in its exploration but, to the author's knowledge, no detailed investigation of this phenomenon has been done.

It has been proposed that the subhydrostatic pore-pressures observed in the Belly River Formation are caused by the dilation of rock pores due to erosion-induced elastic rebound of fine-grained Upper Cretaceous and Tertiary rocks in the Alberta Basin (Putnam, 1989). The purpose of this paper is to describe this phenomenon and to provide supporting evidence for Putnam's explanation.

Because of the confusion of terminology associated with subsurface formation pressures, this study begins with a review of the terms used to describe pore-pressure magnitudes and vertical pore-pressure gradients. Then a detailed theoretical discussion of the proposed mechanism, erosion-induced elastic rebound, and its effects on vertical pore-pressure distributions will follow. Field observations are then detailed and interpreted in light of this theory and conclusions drawn.

Previous Work

It is of interest to note that other investigators have studied the phenomenon of subhydrostatic pore-pressures in other formations in the Alberta Basin and elsewhere in North America.

Hitchon (1969) proposed that subhydrostatic pore-pressures in the Viking Formation of Alberta are being generated by osmosis across thick regional shale units. Tóth (1978) argued that subhydrostatic pore-pressures along, and in formations overlying and underlying, the pre-Cretaceous unconformity in the Red Earth area of Alberta are generated by fluid drainage to the outcrop along the banks of the Athabasca River. Tóth and Corbet (1986) suggested that rock-pore dilation due to elastic rebound is the cause of subhydrostatic pressure occurrence in the Mannville Formation near Taber, Alberta, as did Rakhit (1987) to explain subhydrostatic pore-pressures in the Bow Island Formation in the same area.

Subhydrostatic pore-pressures have been studied elsewhere in North America. Neuzil (1988) explained their presence in the Pierre Shale of North Dakota as being generated by elastic rebound. Belitz and Bredehoeft (1988) and Senger et al. (1987) found that regional cross-formational gravity-flow and basinal variations in the hydraulic conductivity of the rock framework could explain subhydrostatic pore-pressures found in the Denver and Palo Duro Basins, respectively. Elastic rebound was suggested by Russel (1972) to be the cause of subhydrostatic pore-pressures found in the Appalachian Basin. Subhydrostatic pore-pressures have also been reported in the Anadarko, San Juan (Dickey and Cox, 1977), and the Midcontinent Basins and in the Mississippi Valley (Louden, 1972). From these examples, it is clear that regional subhydrostatic pore-pressures are not an uncommon occurrence.

2.2 Theory

2.2.1 Terminology

In a static system, the pore fluids are at rest and the pore-pressures are a function of fluid density and depth below the water table:

$$p = \rho g d \qquad (2.1)$$

where p = pore-pressure; ρ = fluid density; g = acceleration due to gravity; and d = depth below the water table.

Pore-pressures as defined by Equation 2.1 are called hydrostatic. Pore-pressures which are greater in magnitude than expected from Equation 2.1 in a fresh water (ρ = 1000 kg/m^3) system are called superhydrostatic. They are also often called supernormal pressures, abnormal pressures and overpressures. Pore-pressures which are lesser in magnitude than expected in a fresh water system are termed subhydrostatic. They are also commonly called subnormal pressures and underpressures.

The rate at which pore-pressure, p, changes with elevation, z, is called the vertical pore-pressure gradient, dp/dz. In a static column of fresh water, the vertical pore-pressure gradient is -9.80665 kPa/m, which is termed a freshwater hydrostatic gradient. A vertical pore-pressure gradient which is greater than -9.80665 kPa/m in a fresh water system is called a superhydrostatic gradient. One which is less than -9.80665 kPa/m in a fresh water system is called a subhydrostatic gradient. When referring to vertical pore-pressure gradients on a pressure-depth diagram, that is, dp/d(depth),gradients have a positive sign because pressures increase with increasing depth (rather than increase with decreasing elevation).

Superhydrostatic vertical pore-pressure gradients in fresh water systems are indicative of upward motion (Hubbert, 1940). To see why this is so, one must know that groundwater moves from positions of high hydraulic head, which is mechanical energy per unit weight, to low. Hydraulic head has an elevation component and a pressure component. In a static column of water, vertical changes in the elevation component are exactly compensated by changes in the pressure component and therefore hydraulic head remains constant with depth. If pressure increases faster with decreasing elevation than in a column of static fresh water (that is along a superhydrostatic vertical pressure gradient) then hydraulic head increases with depth and water flows upwards. Thus a superhydrostatic vertical pore-pressure gradient is an indicator of upward flow. Similarly, subhydrostatic vertical pore-pressure gradients are indicators of downward flow.

Figure 2.1 illustrates the relationships between the terms hydrostatic, subhydrostatic and superhydrostatic as they relate to both pore-pressure magnitudes and vertical pore-pressure gradients.

2.2.2 The Effects of Erosional Unloading on Pore-Pressure Distributions

Elastic Properties of Rock

Sedimentary rock can exhibit elastic behaviour when placed under compressional or tensional stress. Ideal elastic behaviour is characterized by a linear relationship between stress and strain. The slope of this linear relationship is described by the modulus of elasticity, E = stress/strain. The elastic behaviour of rock is usually described in terms of compressibility, the inverse of elasticity (Freeze and Cherry, 1979):

$$\alpha = \frac{\left(\frac{-\partial V_T}{V_T}\right)}{\partial \sigma_e} \qquad (2.2)$$

where: α = compressibility; V_T = total volume of the rock mass; σ_e = effective stress.

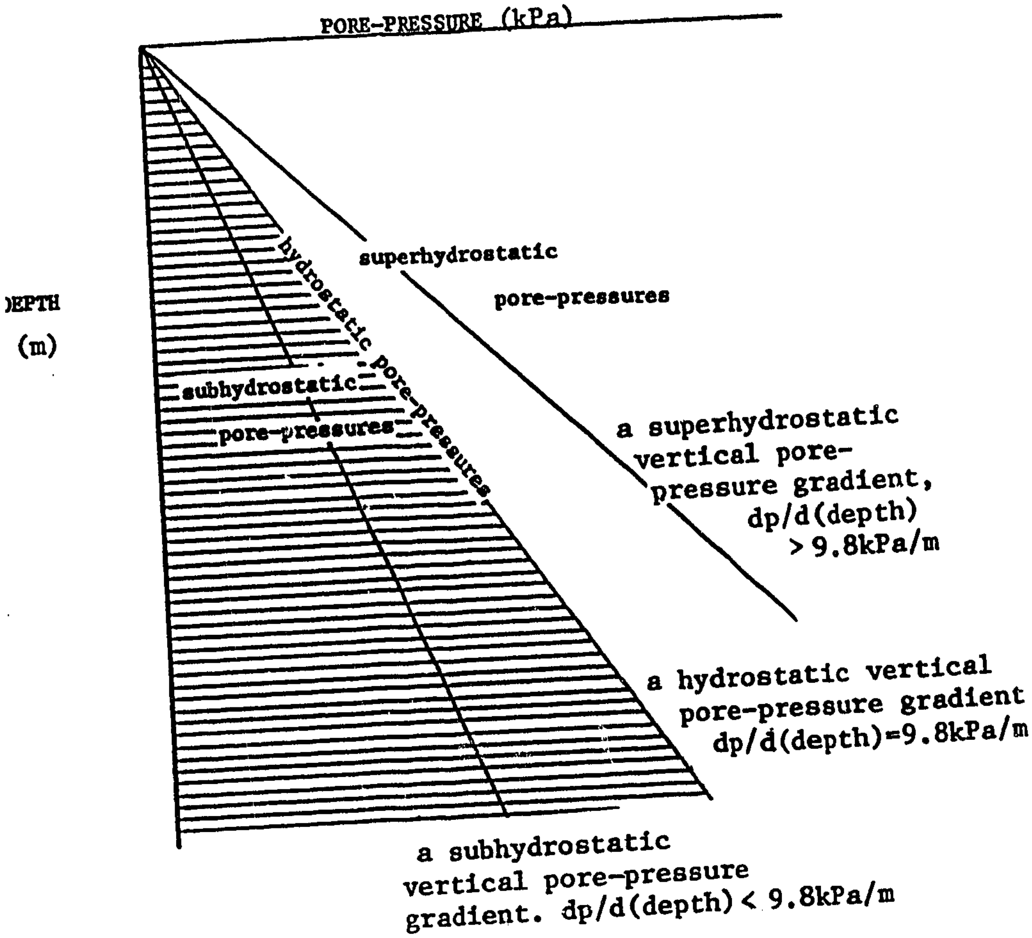

Figure 2.1: Pressure-depth diagram illustrating the use of the terms "hydrostatic", "subhydrostatic" and "superhydrostatic" as they pertain to pore-pressure magnitudes and vertical pore-pressure gradients

The compressibility of rock is a function of lithology, degree of consolidation and stress history. Unconsolidated sediments have compressibilities that range from 10^{-6} m^2/N for clays to 10^{-10} m^2/N for gravels, while sound rock has compressibilities in the range of 10^{-8} m^2/N to 10^{-10} m^2/N (Freeze and Cherry, 1979). Water has a compressibility (symbolized as β) of 4.4×10^{-10} m^2/N. In general, the lower the value of rock compressibility , the more prone to elastic behaviour the rock will be (Freeze and Cherry, 1979, p.86).

The stress history is of particular importance in determining the compressibility of rock because the compressibility develops in a hysteresis-type fashion with repetitive cycles of loading and unloading (Freeze and Cherry, 1979). In this case, the rock behaves as a non-ideal elastic solid because the rebound compressibility is smaller than the pre-burial compressibility and not all the strain energy is recovered when the compressive stresses are reduced. The change is due to factors such as the repacking of grains, cementation, diagenesis, brittle failure of the rock framework and plastic deformation .

The expectable success of modelling the rock deformation history in sedimentary basins is therefore limited. Realistic values of α are difficult to obtain for each layer because of lithologic variations and different stress histories for each layer due to the cycles of erosional and depositional events endemic to all but the simplest of sedimentary basins (Tóth and Millar, 1985). Nevertheless, it is possible to model the effects of changing rock stress-fields on pore-pressure distributions in basins, mathematically for simple cases and conceptually for complex cases.

Models of the Effects of Unloading on Pore-Pressure Distributions

The effects of compressive stresses on pore-pressure distributions are familiar to most geologists. An increase in compressive stress causes pore-pressures to rise if fluids are unable to diffuse out of the rock at a rate fast enough to re-equilibrate pressures to hydrostatic or gravity-flow determined values (Bredehoeft and Hanshaw, 1968). The effects of reduction of compressive stress on pore-pressures are less well known to geologists, though not so to geotechnical engineers who are more familiar with its effects, such as slope failure due to rapid removal of overburden.

The effects of removal of overburden at dam-site excavations, for example, have been noted by several authors. Peterson (1958) noted that the Bearpaw Shale had elastically rebounded at a dam site in Southern Alberta. Scott and Brooker (1966) analysed the slope engineering implications of post-erosional rebounding shales outcropping in Alberta. Matheson and Thomson (1973) used air-photo interpretation and detailed stratigraphic correlations across river valleys at dam sites to establish the physical existence of the elastic rebound of sediments under river valleys caused by the removal of overburden by fluvial erosion.

The effects of large-scale areal erosion and elastic rebound on subsurface pore-pressures are not as well documented. This is due to the usual difficulties inherent in studying any phenomenon on a basin scale, e.g., scarcity of good data, lack of knowledge of physical constants such as regional compressibility, etc.. Nevertheless, there has been an effort to understand the effects of regional erosion on pore-pressures, primarily led by mathematical modellers.

An early numerical model of the effects of erosion on vertical pore-pressure distributions was put forth by Neuzil and Pollock (1983). They used a one-dimensional finite-difference numerical model to simulate the effects of overburden removal and consequent elastic expansion of the rock framework on vertical pore-pressure distributions. In one of their simulations, an aquitard was placed overlying an aquifer. Pore-pressures at the top and bottom were fixed at hydrostatic and the rock framework was allowed to expand elastically in proportion to the compressibility of the rock layers and to the reduction of compressive stress. Their model showed that a pore-pressure sink develops within the aquitard because the rock framework elastically expands and its pores dilate at a rate faster than water can enter to maintain pore-pressures at hydrostatic. Neuzil and Pollock's model indicated that pore-pressure sinks in thick aquitards can exist for periods of the order of 10^6 to 10^7 years.

Tóth and Millar (1983) examined the effects of rapid changes in water-table elevations on vertical pore-pressure distrubutions without allowing for pore-dilation. They found that if the rock framework remains unchanging, erosional events that occur at a rate greater than water can flow across regional aquitards will lead to the creation of superhydrostatic pore-pressures beneath the aquitards. These pore-pressure slowly bleed off through the aquitards over geologic time.

Tóth and Corbet (1986) used a conceptual approach to model the effects of an elastically expanding, regionally-extensive aquitard on the development of gravity-driven cross-formational fluid flow in a simple basin. Their model begins at a time when groundwater flow in the basin is adjusted to the topography. After a rapid erosional event, the topography has been reversed and reduction of overburden stress causes pore-pressures in the aquitard to become reduced and the rock framework to elastically expand. Water then flows into the zone of reduced pore-pressures, raising the pore-pressures and, in turn, allowing the aquitard's pores dilate to dilate some more. This causes further pore-pressure reductions and so on. As a result of this coupled process, the aquitard expands and the pore-pressure sink is maintained. For the purposes of this study, it is instructive to examine in more detail the conceptual model of Tóth and Corbet in terms of what happens to the pore-pressures and vertical pore-pressure gradients when overburden stresses are rapidly reduced.

Figures 2.2a through 2.2e show a conceptual model of the evolution of the pore-pressure magnitudes and vertical pore-pressure gradients based on the model of Tóth and Corbet (1986). For simplicity, the model shows pressure evolution in a hydrostatic case.

Figure 2.2a represents the conditions present at time $t = -\infty$. The pore-pressures are equivalent to hydrostatic and increase with depth along a hydrostatic gradient.

Figure 2.2b shows conditions at $t = 0$, immediately after a rapid erosional event. The pore-pressures increase with depth along the modern hydrostatic gradient until the aquitard is reached. In the aquitard, pore-pressures decrease because the pores of the aquitard dilate faster than water can enter to maintain a hydrostatic

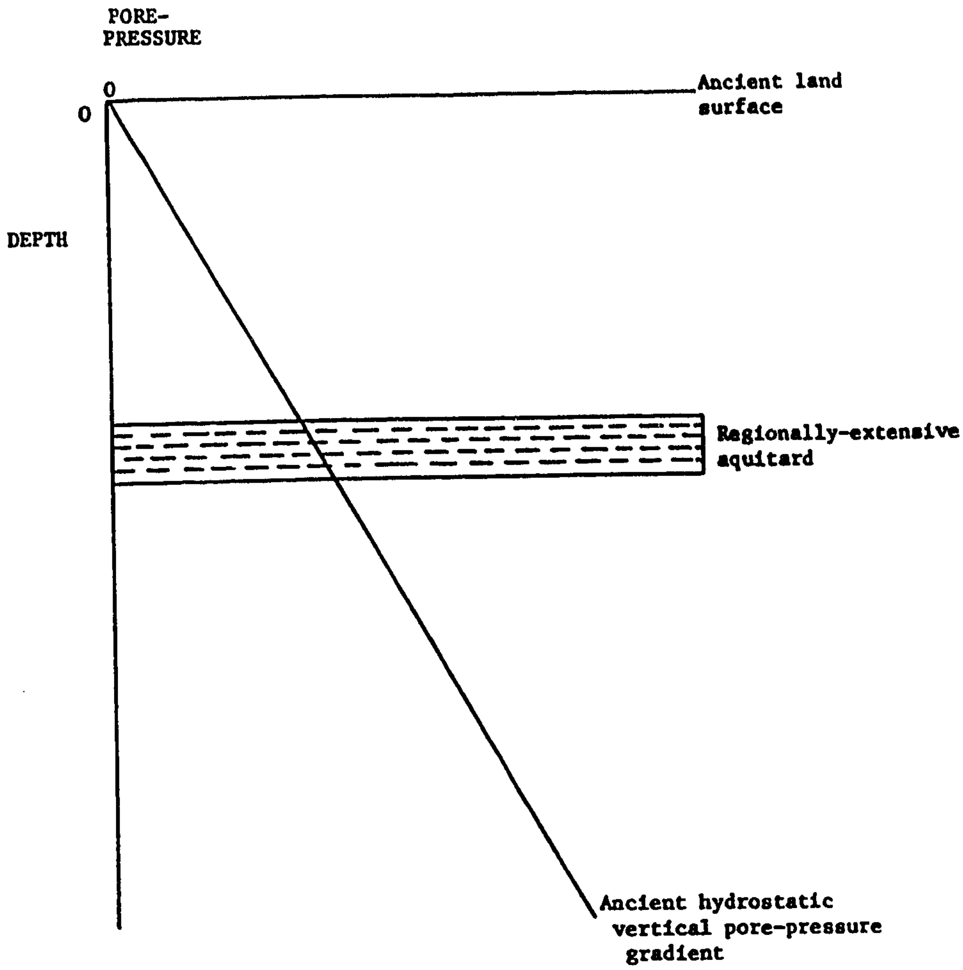

Figure 2.2a: Vertical distribution of pore-pressures at $t=-\infty$, prior to onset of erosion. Pore-pressures are in equilibrium with ancient land surface boundary conditions.

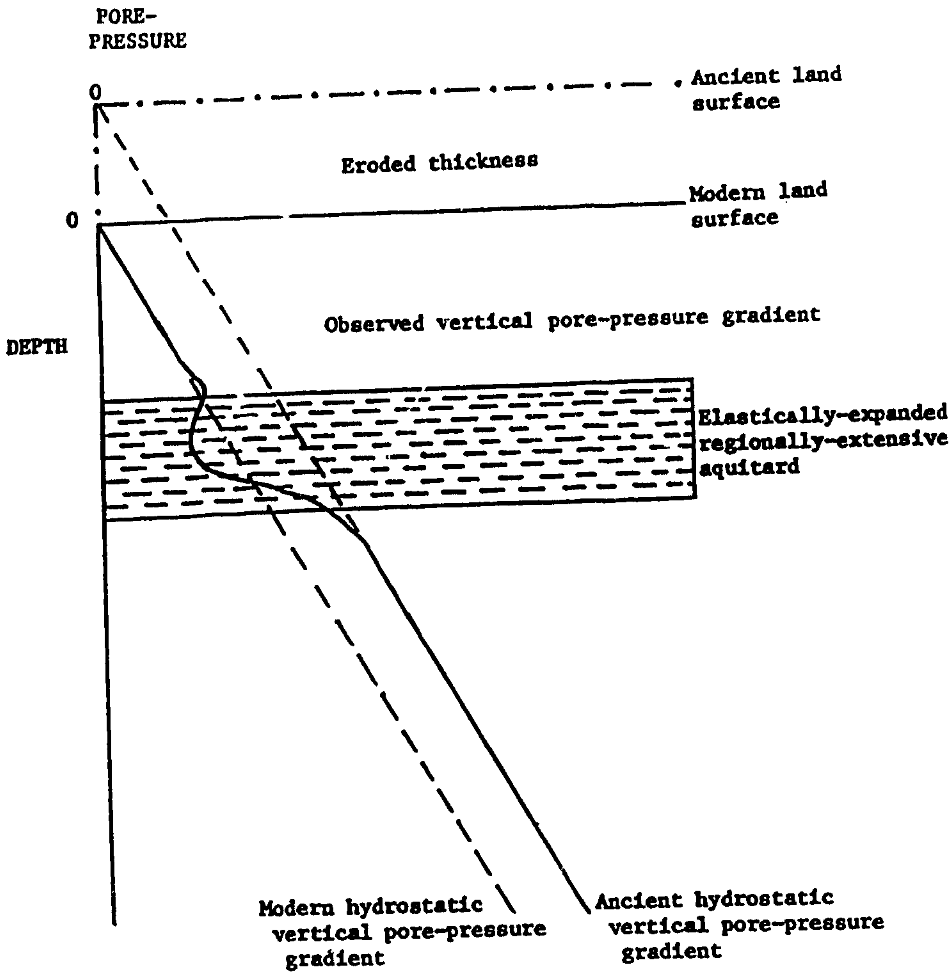

Figure 2.2b: Vertical distribution of pore-pressures at t=0, immediately after a rapid erosional event. Pore-dilation in the regionally extensive aquitard begins to generate a pore-pressure sink. Shallow pore-pressures begin to equilibrate with modern land surface boundary conditions.

equilibrium. The greatest amount of pore-pressure decrease is in the center of the aquitard, where isolation from the water in the aquifers above and below is greatest.

Figure 2.2c shows conditions at $t > 0$. Pore-pressures between the land surface and the aquitard are hydrostatic in magnitude and increase with depth along a hydrostatic gradient until the zone above the aquitard is entered. There, the pore-pressures will fall on a subhydrostatic vertical pore-pressure gradient because water is drawn downwards into the pore-pressure sink. The greatest amount of decrease is still observed in the center of the aquitard. Beneath the sink the vertical pore-pressure gradients is superhydrostatic because water there is being drawn upwards into the pore-pressure sink above. These very effects have been documented in the Pierre Shale of North Dakota by Neuzil (1988).

Farther below in the basin, at $t > 0$, the magnitude of the observed pore-pressures will depend on their depth below the pore-pressure sink. If the pore-pressures in the sink have become subhydrostatic relative to the modern land surface, then the pore-pressures immediately below the sink will also be subhydrostatic. As they increase along a superhydrostatic gradient with depth, at some point the observed vertical pore-pressure gradient will cross the modern hydrostatic gradient and the pore-pressures will become superhydrostatic in magnitude.

Figure 2.2d shows the conditions at an advanced state, $t >> 0$. At this point, enough time has passed for water to enter into the pores of the aquitard to allow it to complete its vertical expansion and restore pore-pressures to hydrostatic. Above and within the aquitard, pore-pressures are hydrostatic in magnitude and increase with depth along a hydrostatic gradient. Below the aquitard, pore-pressures are beginning to adjust to the elevation of the new land surface.

Fig. 2.2e shows conditions at $t = +\infty$. The pore-pressures in the basin have adjusted completely to the modern land-surface elevation. Pore-pressures are hydrostatic in magnitude and the vertical pore-pressure gradient is once again equivalent to hydrostatic.

2.4 Discussion

2.4.1 Elastic-rebound Induced Pore-dilation as the Cause of the Observed Vertical Pore-Pressure Distribution in the Belly River Formation.

The vertical distribution of pore-pressures in the Belly River Formation can be summarized as follows. The Belly River Formation is a hydraulically continuous porous medium which is saturated with fresh water. The pore-pressures are subhydrostatic in magnitude and increase with depth at a superhydrostatic rate.

These conditions are interpreted to be controlled by a pore-pressure sink centered in the Edmonton Formation at a depth of between 600 and 800 meters below the modern land surface.The pore-pressure sink is the product of pressure reduction in pores which have dilated due to the elastic expansion of the rock framework. The elastic expansion was induced by the removal of 2250 meters of overburden by erosion. The erosion followed uplift of the area since the Eocene due to the Laramide Orogeny.

Field evidence supports this conclusion. Pressure-depth plots show pore-pressures to be the most underpressured in the interval between 600 and 800 meters below the modern land surface. Above and below this zone, pore-pressures are less subhydrostatic. In the Belly River Formation, the vertical pore-pressure gradient is superhydrostatic. In the Paskapoo Formation, the vertical pore-pressure gradient is subhydrostatic. These gradients indicate water is moving downward from above and upward from below. In addition, shale porosities tend to be anomalously high in the Edmonton Formation, lending support to the contention that rock-pores have dilated.

Quantifying the relationships between the strength and longevity of the pore-pressure sink and the amount and rates of overburden removal since the Eocene remains an intractable problem. Efforts made in this study to put limits on the change in porosity expected given the amount of unloading, even assuming it to be instantaneous, failed due to lack of available estimates of the compressibility of the Edmonton Formation. Even data from the literature for the compressibilities of simple rock types that could be used to model the Edmonton Formation fall across several orders of magnitude (e.g., Freeze and Cherry, 1979, p. 55), making even educated guesses at the compressibility subject to errors of orders of magnitude. This problem holds true for estimating regional permeabilities, erosional rates, and just about every other constant needed to quantify the process of regional elastic expansion of the rock framework, let alone the problems inherent in modelling the evolution of the pore-pressure sink over time. For these reasons, quantitative analysis of the pore-pressure sink phenomenon remains beyond the scope of this work.

2.4.2 Evolution of Groundwater Flow in the Belly River Formation

The recognition of the pore-pressure sink phenomenon enables us to unravel the paleo-hydrogeological evolution of the Belly River Formation in the study area and consider some important implications of its past, present and future states to hydrogeological investigations.

The vertical pore-pressure distribution in the Upper Cretaceous and Tertiary strata of the study area indicates that the present groundwater flow system is not in equilibrium with the modern land surface. Flow has not yet evolved into a gravity-flow system driven by modern topography because of the pore-pressure sink in the Edmonton Formation.

There is, however, evidence of the existence of large-scale cross-formational flow of meteoric water in the past, such as illustrated in Figure 2.13. Longstaffe (1986) documents geochemical evidence which supports the contention that large-scale cross-formational flow of meteoric water occured in the past in the Belly River Formation in west-central Alberta. Study of diagenetic cements in basal Belly River sands from an oil pool (in T48 R6 and R7 W5M, north of the present study area) showed that their oxygen isotope composition requires that meteoric water

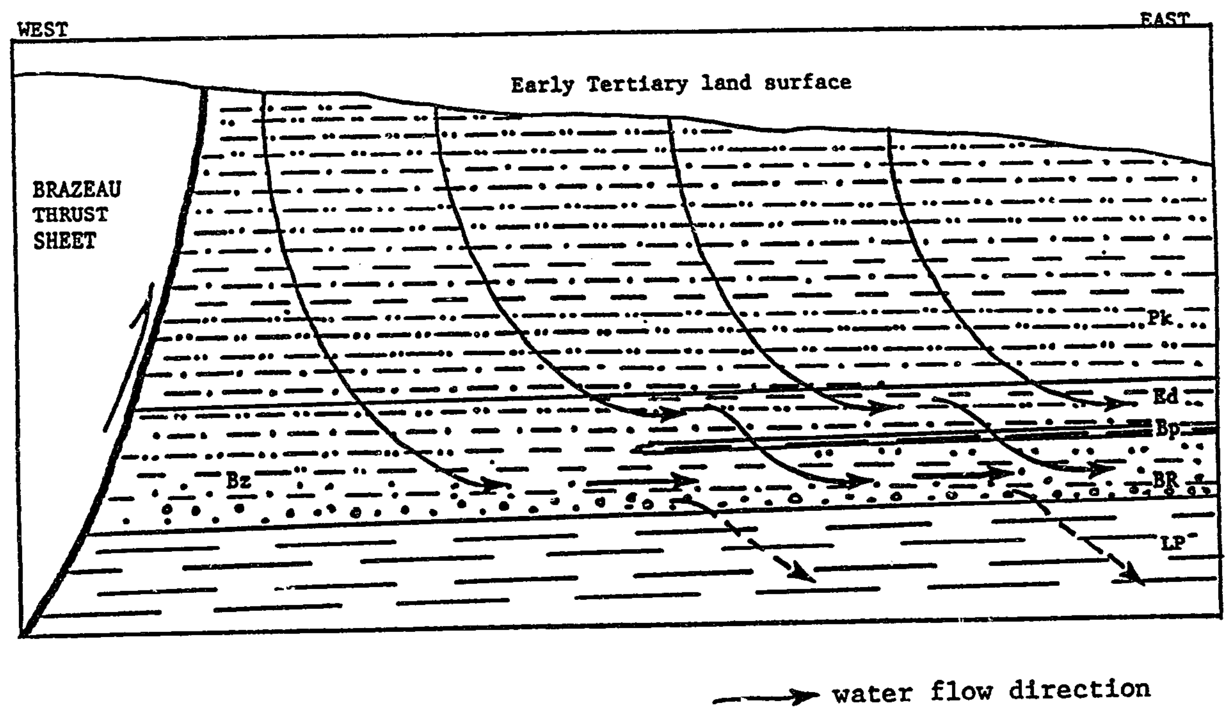

Figure 2.13: Schematic illustration of west-to-east, gravity-driven cross-formational flow system which may have existed in the early Tertiary in west-central Alberta.

passed through the sandstones at temperatures which are associated with deeper burial than present. These temperatures are believed to correlate with the maximum depth of burial of the sediments following the second major pulse of the Laramide orogeny during the Eocene.

At some point, in time following the uplift and erosion that began in the mid-Tertiary, the pore-pressure sink was generated. It may have always been present because of constant unloading or may be a more recent phenomenon. It can only be said for certain that it has existed long enough for the pressure disturbance it has created to propagate through the Belly River Formation, a vertical distance of nearly 1000 meters.

The westward lateral hydraulic gradient may be a product of both a westward increase in the strength of the pore-pressure sink and the regional interaction of the pore-pressure sink and the geology of the basin. As the amount of overburden removed increases to the west, the amount of pore-dilation is also likely to increase. The westward increase in the strength of the pore-pressure sink then creates the observed westward decrease in hydraulic heads.

The geology may also contribute to the creation of the westward flow. In the study area, the Bearpaw Formation is functioning as an aquitard separating the Belly River Formation from the Edmonton and Paskapoo Formations and the hydraulic sink. It is known that to the west the Bearpaw Formation is absent and that the Belly River Formation is no longer separated from the Edmonton Formation. There the pore fluids in the Belly River Formation are probably much more affected by the presence of the pore-pressure sink. A high degree of lateral hydraulic communication along bedding in the Belly River Formation conducts this effect eastward, under the Bearpaw Shale. In addition, the Bearpaw Formation, being a shale, may be contributing to the creation of the pore-pressure sink through its own expansion as it is known to be prone to elastic rebound in the shallow subsurface (Peterson, 1958). These factors generate the westward and upward components of groundwater flow observed in the Belly River Formation (Figure 2.14).

The future evolution of the flow systems and vertical pore-pressure distribution

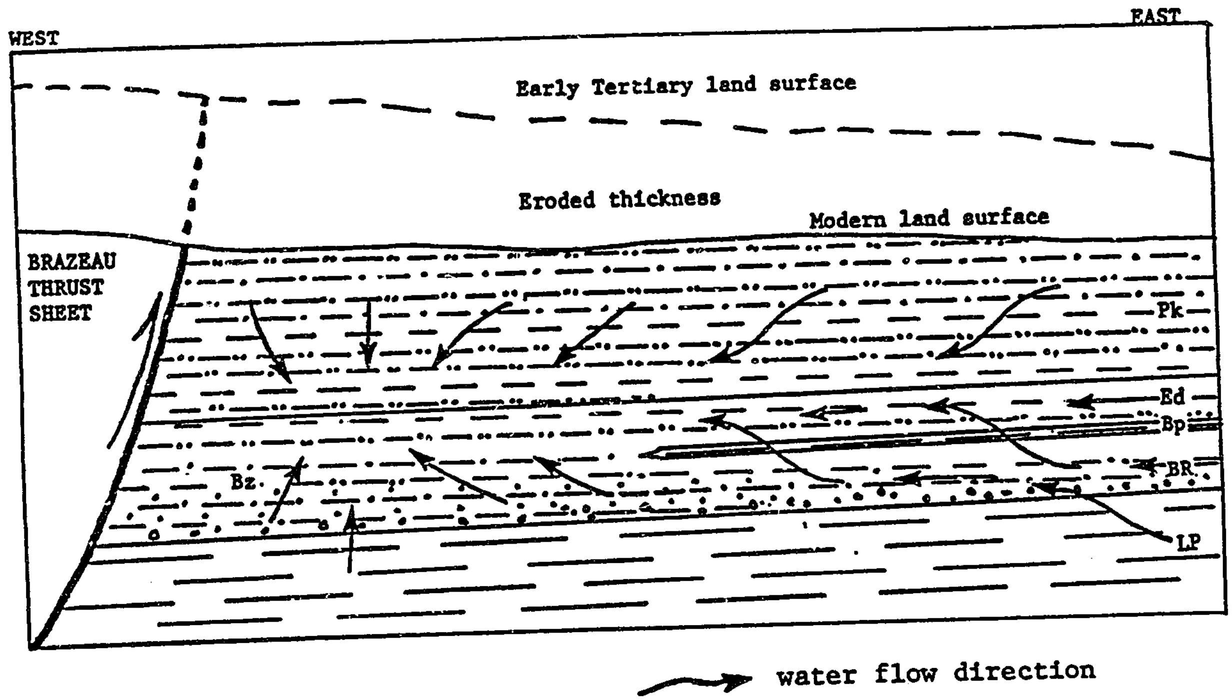

Figure 2.14: Schematic illustration of flow-system present today in west-central Alberta. A pore-pressure sink is drawing fluids in the Belly River Formation upwards and to the west.

will be controlled by the decay time of the pore-pressure sink. Once the sink has decayed through diffusion of water into the dilated pores, the effect sof the topography can propagate downwards through the sedimentary column. Then a gravity-flow system will regenerate.

2.4.3 Implications

The nature of the flow field has several important implications. First, the presence of a hydraulic gradient generated by the pore-pressure sink facilitates the application of potentiometric surface analysis to exploration efforts in the Belly River Formation. Tóth and Rakhit (1988) demonstrated how potentiometric maps can be used to prospect for highly permeable lenticular rock bodies. Among the necessary requisites is the presence of a hydraulic gradient. From this study, it can be assumed that the same upward and westward hydraulic gradients should exist over a large area of west-central Alberta because the controlling factors on the study area are regional in nature. Therefore the application of Tóth and Rakhit's techniques may be of use to explorationists interested in the Belly River Formation.

Second, the presence of transient pore-pressure sinks affects the engineering of disposal of toxic or radioactive wastes by deep injection into sedimentary basins. In the case of radioactive wastes, they must be isolated from the biosphere for potentially hundreds of thousands to millions of years. If the modern flow system is transient in nature, then the flow system into which wastes are introduced will be changing over the period of time necessary for the wastes to decay into less harmful substances. This is a factor which must be taken into account. It is conceivable, in the case of the Belly River Formation, for example, for the flow system to change directions once the pore-pressure sink has decayed away.

On the other hand, it has been recognized (e.g., Neuzil and Pollock, 1983) that pore-pressure sinks may also serve as waste repositories. Knowing that water is moving into but not out of the rock where such a sink has been generated makes such strata attractive for waste disposal. Using them as repositories would minimize or negate the distance that contaminants would move by advection, leaving only transport by diffusion as a source of leakage.

A third important implication of the recognition of pore-pressure sinks in sedimentary basins is that they will affect water resource planning. If an area is undergoing industrial development that requires withdrawal of significant volumes of groundwater, there is potential for difficulties caused by the presence of a pore-pressure sink. If such a sink is present, its effects may be felt high up in the sedimentary rock column in the form of reduced available drawdown because of the downward flow of water into the sink. Hydrogeologists should be aware of this possibility.

2.5 Summary and Conclusions

The presence of subhydrostatic pore-pressures, commonly referred to as underpressuring, in the Upper Cretaceous Belly River Formation has been known to industry geologists for a long time but never explained. This study supports the propostion (Punam, 1989) that post-Eocene erosion-induced elastic rebound of the rock framework and the concommitant dilation of the rock pores therein has created a pore-pressure sink in the Upper Cretaceous Edmonton Formation. This sink, in turn, has caused the Belly River Formation pore-pressures to become subhydrostatic in magnitude and also to move upwards cross-formationally.

Such a mechanism was first explained quantitatively by the models of Neuzil and Pollock (1983) and of Tóth and Corbet (1986). They showed how the reduction of fluid pressures in the dilated pores generates a pore-pressure sink. This sink affects the pore-pressures in over- and underlying strata because it induces, by its existence, a hydraulic head gradient. In the case of underlying strata, fluids will move upwards into the pore-pressure sink because fluid pressures increase with depth at a superhydrostatic rate and therefore the hydraulic heads increase with depth. Depending on the magnitude of the pressure-decrease in the dilated-pore zone, the thicknesses and permeabilities of the rock units and the time since the occurrence of the dilation, the pore-pressures in the underlying strata can either be subhydrostatic or superhydrostatic.

Pore-pressures in the Belly River Formation in the study area plot along a superhydrostatic vertical pore-pressure gradient but are subhydrostatic in magnitude relative to the modern land surface. The formation waters are fresh. There exists a west-lateral hydraulic gradient in the lower sands of the Belly River Formation in the study area.

To explain these observations, several mechanism of generating the observed pore-pressure distribution were considered. Two of these, namely pressure control via outcrop and pressure distribution control via regional groundwater discharge, were rejected. The third, elastic-rebound induced pore-dilation and consequent formation of a pore-pressure sink in overlying strata, was accepted.

This mechanism was accepted because pore-pressures in the Edmonton Formation and Paskapoo Formation fall on along a p(d) gradient with the Belly River Formation data in a manner very consistent with the models. It is also known that over 2000 meters of sediment have been eroded from this part of the basin since Eocene time. Prior work by Locker (1973) indicated that the bulk mechanical behaviour of Upper Cretaceous and Tertiary rock in west-central Alberta allows for the possibility of elastic rebound following this overburden removal.

The superhydrostatic vertical pore-pressure gradient in the Belly River Formation is the consequence of upward cross-formational fluid flow into the pore-pressure sink. The subhydrostatic magnitudes of the pore-pressures in the Belly River Formation is a consequence of this flow and of the magnitude of the pressure reduction in the dilated-pore zone. The pore-pressure sink is located at approximately 600-800 meters below the modern land surface, in the Upper Edmonton Formation.

The dilated-pore zone's existence is corroborated by analysing sonic travel-time through shales versus depth of burial. It was discovered that shale porosities tend to be anomaolously high in strata which overlie the zone of greatest underpressuring, around 500-600 meters below the land surface. The lack of vertical coincidence of the greatest underpressuring and the shale-porosity anomalies is caused by the complex coupled-relationships between elastic expansion of rock and water influx into the resulting pore-pressure sink. The shales which are most underpressured show no anomalous porosity because water has not yet infiltrated into the pores to reduce the fluid-tensional forces acting to retard the expansion. The shales which have anomolously high porosities are not as severely underpressured because water has infiltrated in sufficient quantities to allow the pores to dilate as well as bring the pore-pressures closer to hydrostatic magnitudes.

The westward decrease in hydraulic heads are believed to be a product of a trend towards more severe underpressuring west of the study area plus a higher degree of lateral hydraulic communication to the west than vertically across the Bearpaw

Formation. The flow in the Belly River Formation is interpreted to be controlled by the pore-pressure sink.

The future evolution of flow in the Belly River Formation and in the whole Upper Cretaceous and Tertiary sedimentary rock column will be controlled by the rate of decay of the pore-pressure sink. Eventually, the modern land-surface topography will begin to generate and control gravity-flow systems.

This work has implications for practical geologic applications. First, the existence of a regional hydraulic gradient in the Belly River Formation means the formation is amenable to exploration through potentiometric mapping. Second, any disposal of hazardous waste by deep-injection must account for the presence and transient nature of the pore-pressure sink in the Edmonton Formation. Third, the presence of the pore-pressure sink means that there is a smaller available regional drawdown in aquifers affected by its presence than would be expected if conditions were in equilibrium with the modern land surface.

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3 A Hydrodynamic Study of an Oil and Gas Pool in the Belly River Formation, West-central Alberta.

3.1 Introduction

Petroleum geologists traditionally rely on their knowledge of sedimentology, structure and stratigraphy, plus a large amount of good luck, to lead them to hydrocarbon deposits. It is becoming more apparent, however, that an understanding of the principles of fluid flow through porous rock promotes success in finding and developing subtle and complex petroleum reservoirs. The recent and rapid rise in the number of flow-related papers published in the petroleum geology literature attests to this fact, e.g., Tóth and Rakhit, 1988; Belitz and Bredehoeft, 1988; Wells,1988; Vugrinovich, 1988; Garven, 1989; Rostron and Tóth, 1989. This study continues the efforts to raise the level of overall consciousness of the place of fluid-flow study in petroleum geology. It presents a hydrodynamic analysis of a hydrocarbon pool in the Upper Cretaceous Belly River Formation of west-central Alberta, Canada. By developing such an analysis in the context of a geological study of a type familiar to most petroleum geologists, the utility of hydrogeology, of which hydrodynamics is a major part, as applied to petroleum exploration will be recognized.

The study is divided into three sections. The first section is an examination of the flow of groundwater and entrapment of petroleum in and around highly permeable rock bodies.The second section is a hydrodynamic study of the Upper Cretaceous Belly River Formation of west-central Alberta examining the relationships between the geology and regional groundwater flow in these sands by using analysis of potentiometric maps and vertical pore-pressure gradients. The third section examines how the hydraulic relationships between the geology and groundwater act to collect and trap hydrocarbons in the study area. The implications on our understanding of petroleum migration and of the functioning of petroleum traps in the Belly River Formation are considered.

3.2 Theory

3.2.1 Equations Governing Groundwater Motion

Groundwater flows through permeable rock in response to fluid-potential gradients: it moves from high to low fluid-potential. Fluid-potential is defined, and can be calculated, by (Hubbert, 1940):

$$\Phi = gz + \frac{p}{\rho} \qquad (3.1)$$

where Φ = fluid-potential; g = acceleration due to gravity; z = elevation relative to a datum; p= fluid pressure; ρ = fluid density.

Hydrogeologists often use the term hydraulic head, h, interchangeably with fluid-potential.They are related by:

$$\Phi = gh \qquad (3.2)$$

The general equation of groundwater flow through isotropic, homogeneous rock, which describes both steady-state and transient flow, can be written as (Davis and Dewiest, 1966):

$$\frac{\partial^2 h}{\partial x^2} + \frac{\partial^2 h}{\partial y^2} + \frac{\partial^2 h}{\partial z^2} - 2g\beta\rho\frac{\partial h}{\partial z} = \frac{S_o}{K}\frac{\partial h}{\partial t} \qquad (3.3)$$

where h = hydraulic head; g = acceleration due to gravity, β = compressibility of water; ρ = water density; S_o = specific storage of the rock; K = the hydraulic conductivity of the rock. For steady-state conditions in a homogeneous and isotropic porous medium, Equation 3.3 simplifies to the Laplace Equation:

$$\frac{\partial^2 h}{\partial x^2} + \frac{\partial^2 h}{\partial y^2} + \frac{\partial^2 h}{\partial z^2} = 0 \qquad (3.4)$$

The rate at which groundwater flows through rock is governed by Darcy's Law:

$$\vec{q} = -K\overrightarrow{\text{grad}}h \qquad (3.5)$$

where $\vec{q}$ = specific volume discharge; K = the hydraulic conductivity of the rock; $\overrightarrow{\text{grad}}$ h = the hydraulic head gradient. The hydraulic conductivity of the rock is a function of rock and fluid properties:

$$K = \frac{kg\rho}{\mu} \qquad (3.6)$$

where k= intrinsic permeability; ρ = fluid density; g = acceleration due to gravity; μ = fluid viscosity. This work assumes that Darcy's Law holds for sedimentary rock in the study area.

3.2.3 Lens-Associated Potentiometric Field Distortions

Tóth (1962) used an analytical solution of the Laplace Equation (Equation 3.4) to solve for the distribution of fluid-potential in a rock volume in which a highly permeable lens was encased within a less permeable, homogeneous matrix. It was shown that the lens will distort the flow field in such a manner as to generate anomalously low fluid-potentials around the upstream end and correspondingly high potentials around the downstream end, relative to the potentials expected given the regional potentiometric gradient. This causes water flow to converge into the lens, pass through it and diverge out of its downstream end (Figure 3.1). Field observation showed that these characteristic potential-field distortions can be used to map permeable lenses in the subsurface (Tóth, 1966). Further theoretical work showed that lenses in a groundwater flow field can act as hydrodynamically

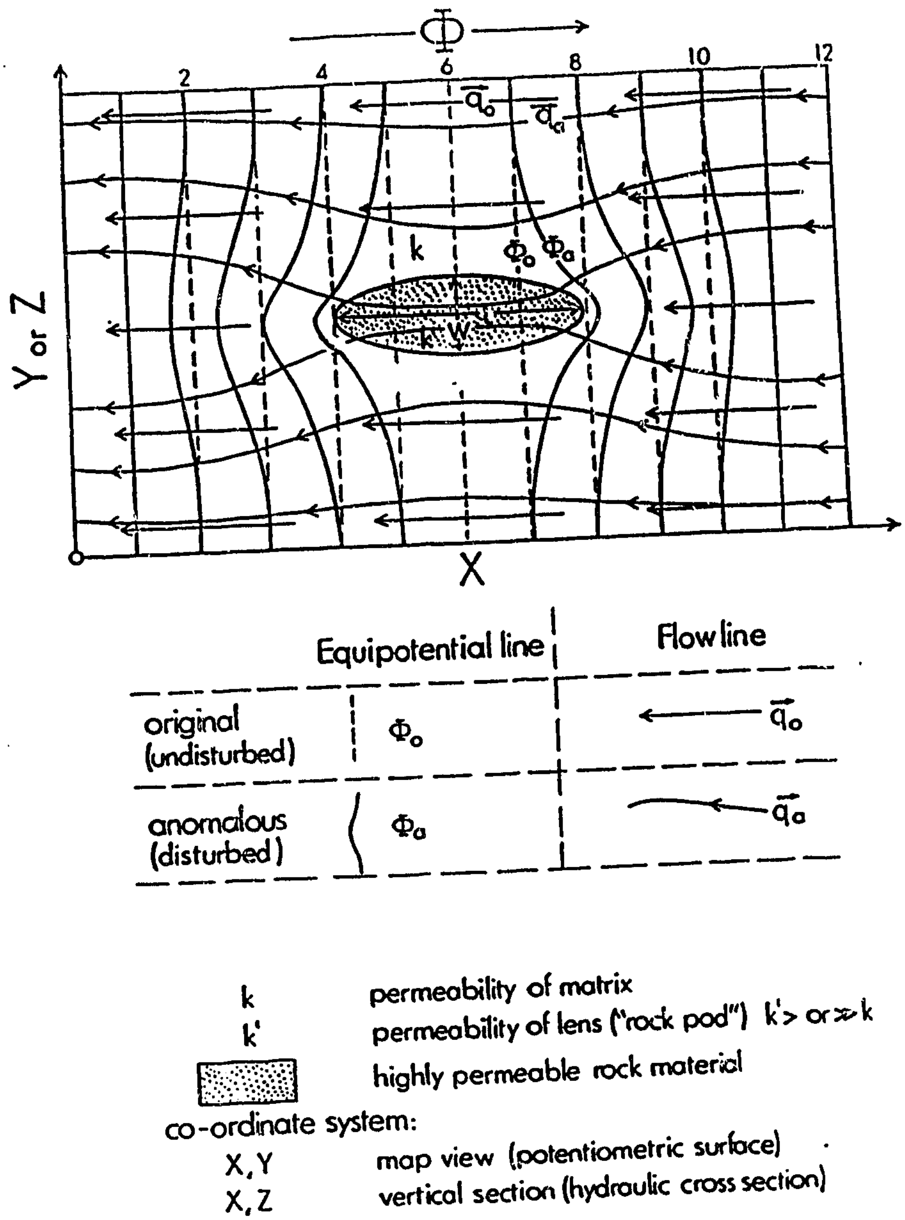


Figure 3.1: Schematic representation of the effect of a highly permeable rock-lens on the configuration of originally uniform fields of fluid flow and fluid potential (modified from Tóth and Rakhit, 1988).

favourable sites for petroleum accumulations (Tóth,1970).

Tóth and Rakhit (1988) used numerical models to quantify the effect of lenses on flow fields. Five parameters were identified to control the magnitude and geometry of the lens-associated potentiometric-field distortions. These are the hydraulic gradient, the permeability contrast between the lens and the matrix, the size and shape of the lens, the orientation of the lens with respect to flow and the anisotropy of the rock permeability. In addition, Rostron and Tóth (1989) found that the presence of hydrocarbons can also affect the distortions. Of particular importance to this study is the effect of lens orientation on the fluid-potential field distortions. As many groundwater systems have components of flow oblique to bedding, models of flow oriented parallel to bedding may be unsuited for study of field situations.

Tóth and Rakhit (1988) looked at the effect of lens orientation on the potential-field distortions. They found that when a lens is rotated to a position oblique to flow, the anomalies shift away from the ends of the lens in a direction opposite to that of rotation. For example, a lens dipping to the west in a potential field inducing flow upwards and to the west will generate anomalies that are displaced downwards at the lens' upstream end and upwards at the lens' downstream end (Figure 3.2). Since potentiometric maps are two-dimensional and most often made on planes parallel to bedding, the geologist interpreting these maps must be aware of these three-dimensional effects.

3.2.5 Rock Lenses as Petroleum Traps

Rock lenses function as petroleum traps on two different scales. One is the regional scale where the rock bodies act like highly permeable lenses that alter fluid-potential fields. The other scale is the pore scale, where capillary forces are important.

The effects of highly permeable lenticular rock bodies on regional groundwater flow are discussed above. In the case where a non-aqueous petroleum phase is

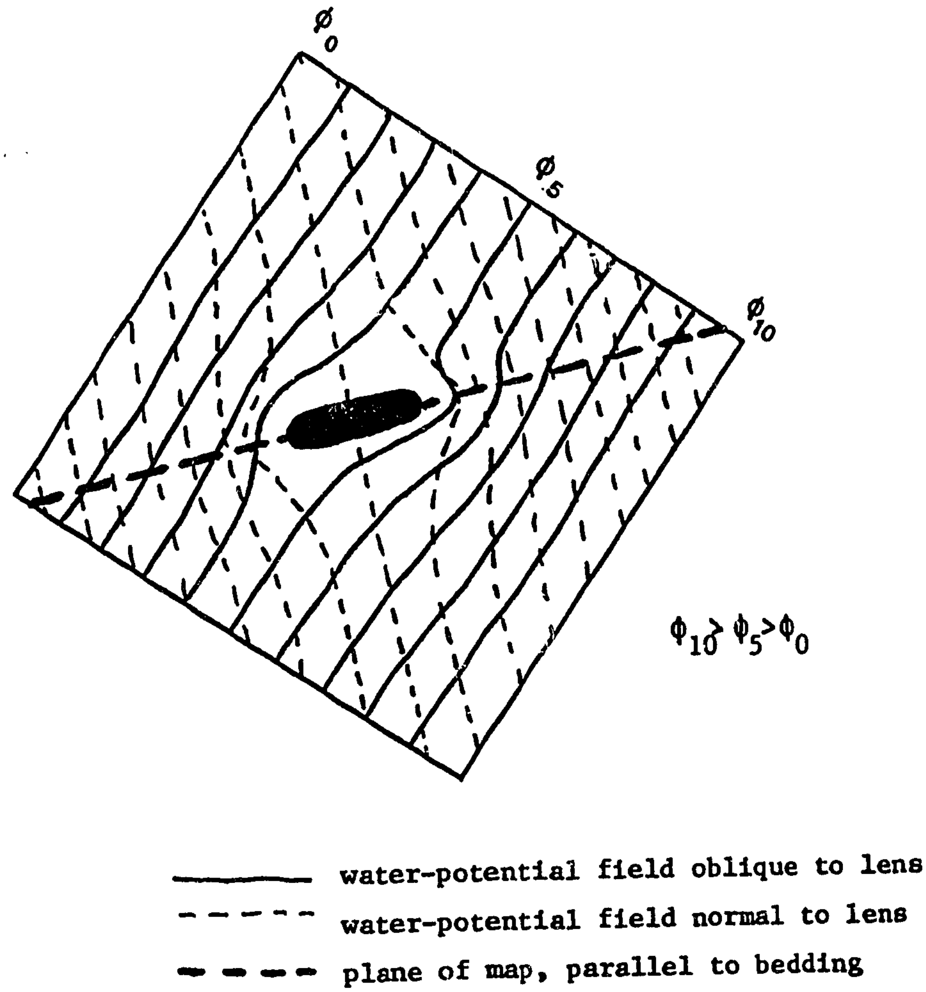


Figure 3.2: Schematic representation of the effect of rotation of a highly permeable rock-lens on its disturbance of the fluid-potential field. If heavy dashed line were to be a map plane, the downstream anomaly would be shifted above the plane of the map (modified from Tóth and Rakhit, 1988).

moving with the groundwater, it has been shown by Hubbert (1953) that the fluid-potential field for oil, in the absence of capillary effects, is the sum of the fluid-potential field for water and the buoyancy force-field. That is, the force acting on a drop of oil is the vectorial sum of the groundwater impelling-force and the buoyancy force. This means that the distortions of the fluid-potentials for water induced by the presence of a rock lens may be observed in the fluid-potentials for oil (Rostron and Tóth, 1989). Thus rock lenses will act as focal points of oil migration.

Once petroleum has entered the rock lenses, it is trapped within by the capillary forces which act on the pore scale. Capillary forces are those forces acting on a non-wetting liquid phase which tend to force that phase into rock pores of increasing diameter and act to prevent them from entering rock pores of smaller diameter (Hubbert, 1953). Capillary-force gradients exist wherever there are grain-size changes and two immiscibile liquid fluids occupying the pore spaces. As rock lenses are defined in space by lithologic changes, capillary-force gradients must surround them. These forces act to impell non-wetting hydrocarbons across the bounding surface of the rock lenses and keep them trapped inside (Tóth, 1970).

Roberts (1980) described oil and gas traps as a paradox for the reason that to function, i.e., to trap, they must leak. He also saw them as active focal mechanisms of discharging waters and as filters of water-borne hydrocarbons. Rock lenses fit Roberts' description very well. Through their distortion of fluid-potential fields and the existence of surrounding capillary gradients, rock lenses act as focal mechanisms of subsurface fluid flow. They leak the flowing groundwater and simultaneously filter-out water-borne hydrocarbons. In short, rock lenses in a water-flow field have the potential to act as petroleum traps because of the hydraulic effects induced by their existence which result in the collection and retention of petroleum.

3.3 Field Study

3.2.1 Study Area

The study area is discussed on page 19 and shown in Figure 3.3.

3.3.2 Geology of the Belly River Formation

Regional Overview

The Belly River Formation is a Late Cretaceous (Campanian) heterogeneous clastic sequence comprising interbedded and often lenticular conglomerates, sandstones, siltstones, shales, mudstones and coals (Lerbekmo, 1963). It was deposited first under marine conditions and then under increasingly continental conditions in an eastward-thinning clastic wedge. Its eastward progradation followed the withdrawal of the Lea Park Sea, coinciding with a time of uplift to the west during a major pulse of the Laramide Orogeny (Stott, 1984). The Belly River Formation is diachronous, becoming younger to the west (Shouldice, 1979).

The stratigraphy applicable to the study area is discussed on page 21 and shown in Figure 3.4.

Because the Belly River Formation represents a clastic wedge which prograded laterally into an epiric sea over time, both nearshore marine and continental deposits are represented in the formation. For example, Iwuagwu and Lerbekmo (1984, p.391)) recognized, in one 23 meter-long core of the lower Belly River Formation, depositional environments which include delta front, distal bar, stream-mouth bar, marsh, crevasse splay, marshy bay, fluvial channel and channel floor. The presence of so many different types of deposits contributes to the overall heterogeneity of the formation and is the cause of many of the difficulties petroleum geologists face in developing exploration plays in the Belly River Formation. This is one reason why a fresh new approach to exploration, such as one incorporating hydrogeology, may have merit in aiding geologists to explore the Belly River Formation.

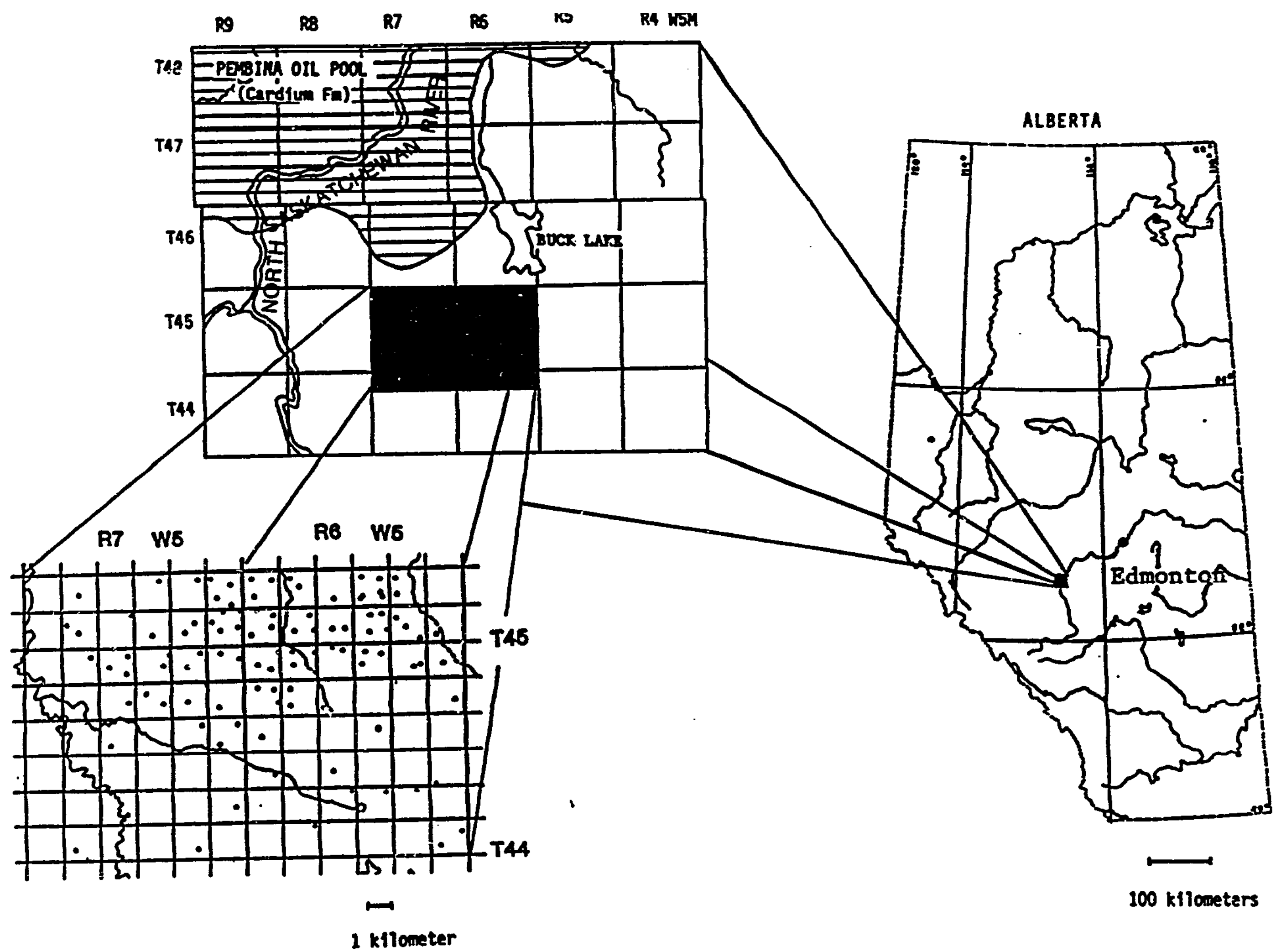


Figure 3.3: Location of study area.

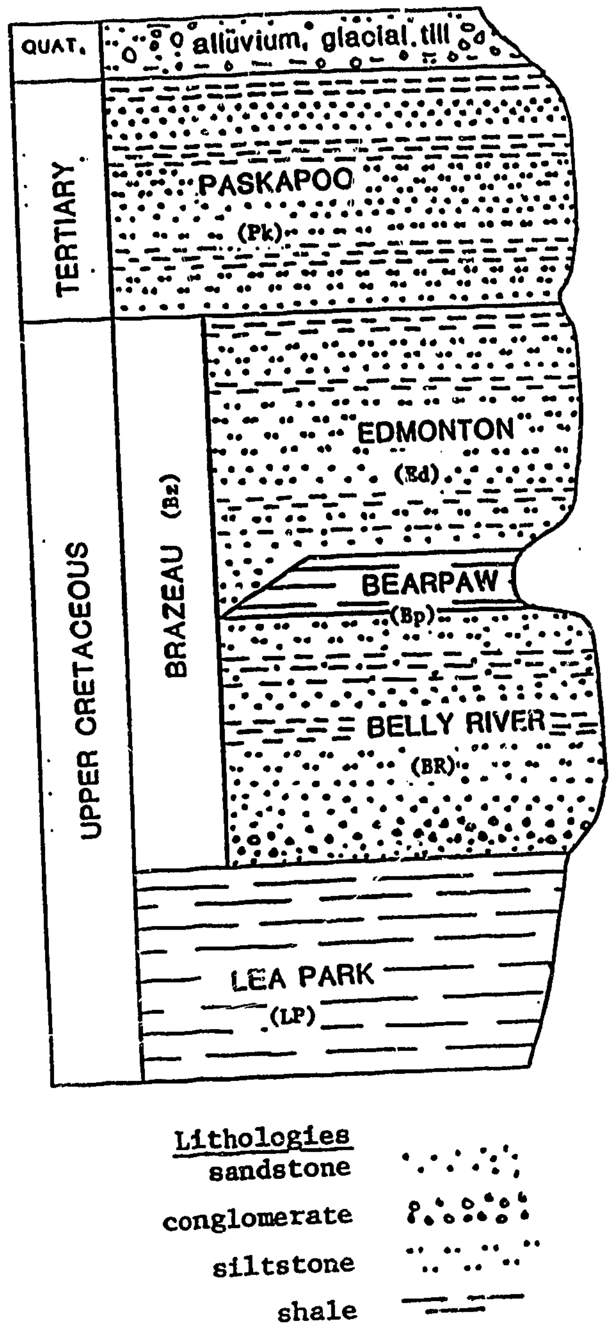


Figure 3.4: Principal stratigraphy, Upper Cretaceous and Tertiary of west-central Alberta.

Previous Work

According to Stott (1963), the Belly River Formation was originally described by G.M. Dawson of the Geological Survey of Canada in 1884. He used the term to describe the thick continental beds underlying the Pierre Shale and which are exposed along the banks of the Belly River southeast of Lethbridge, Alberta. The term was replaced by the names Foremost and Oldman Formations in southern Alberta (Russel and Landes, 1940) but the name "Belly River Formation" was kept in use to describe the sequence farther north where it could not be conveniently subdivided (Stott, 1963). McLean (1977) proposed that the term "Judith River Formation" replace the terms "Belly River Formation", "Oldman Formation" and "Foremost Formation." This change has not been widely accepted among geologists in Alberta who retain the use of the term "Belly River Formation".

Podruski et al. (1988) define the Belly River Formation petroleum potential in terms of two different plays: the Belly River Fluvial Play and the Belly River Shoreline Play. Both are stratigraphic types of petroleum traps. In this paper, the reservoir which is studied falls into the category of the Belly River Fluvial Play. Geochemical evidence suggests a Colorado Formation (a lower Cretaceous marine shale which underlies the Lea Park Formation) source for the oil found in the Belly River Formation (Creaney and Allan, in press), though it is generally believed that some gas is derived from local coal beds. It is hypothesized by Creaney and Allan that the Colorado-sourced oils migrated from the deep basin up open faults of the Alberta foreland thrust and fold belt and then laterally updip and eastward through the interconnected sand beds of the Belly River Formation.

Geology of the Lower Belly River Sands in the Study Area

The Belly River Formation in west-central Alberta is not further subdivided into formally recognized stratigraphic units. Informally, however, the lowest sands are often referred to as the basal Belly River sands. The term "basal" usually applies only to those lowermost sands of marine origin, though sometimes the term includes sands which are stratigraphically higher and of a continental nature. In this study,

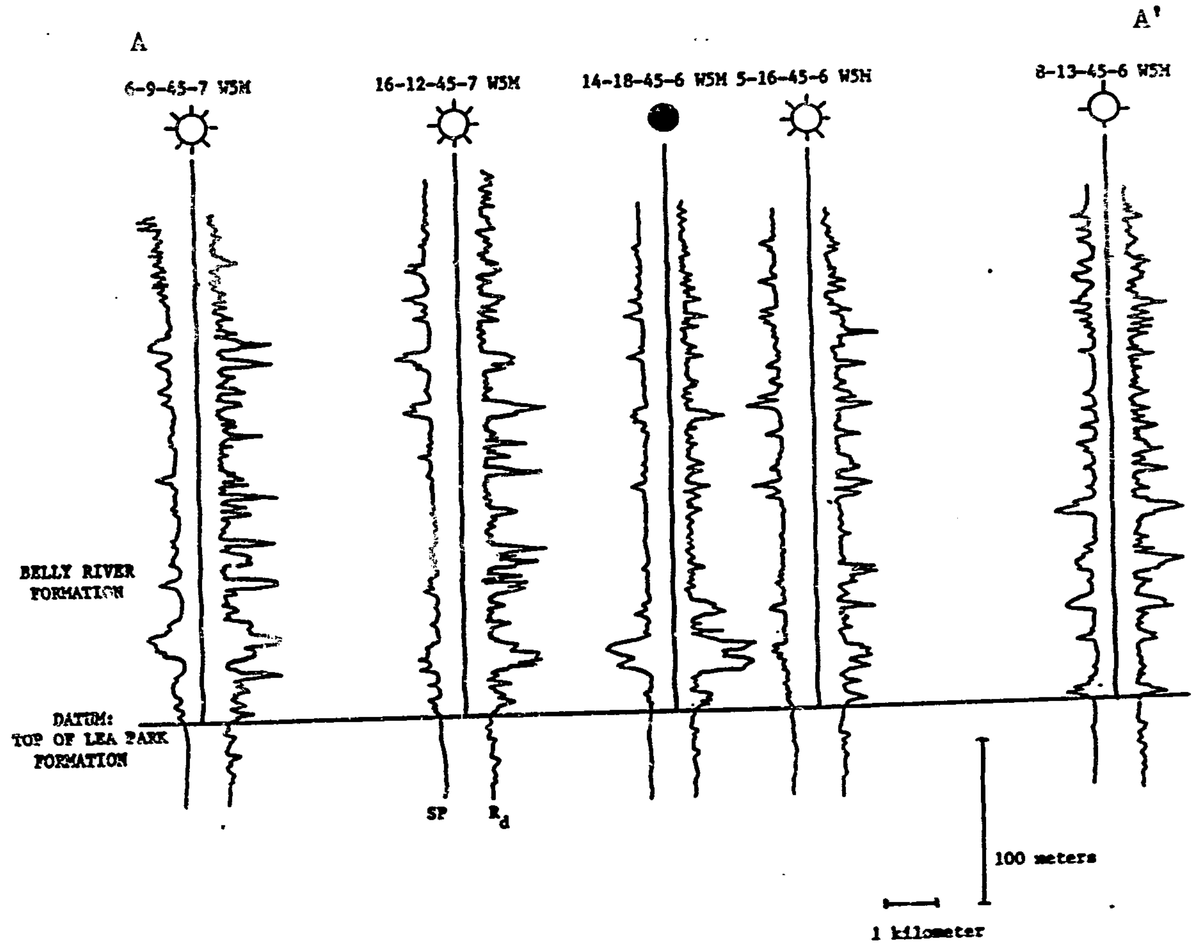


Figure 3.5: Stratigraphic cross-section A-A', west-to-east through Belly River Formation in study area. (See Figure 3.6 for location)

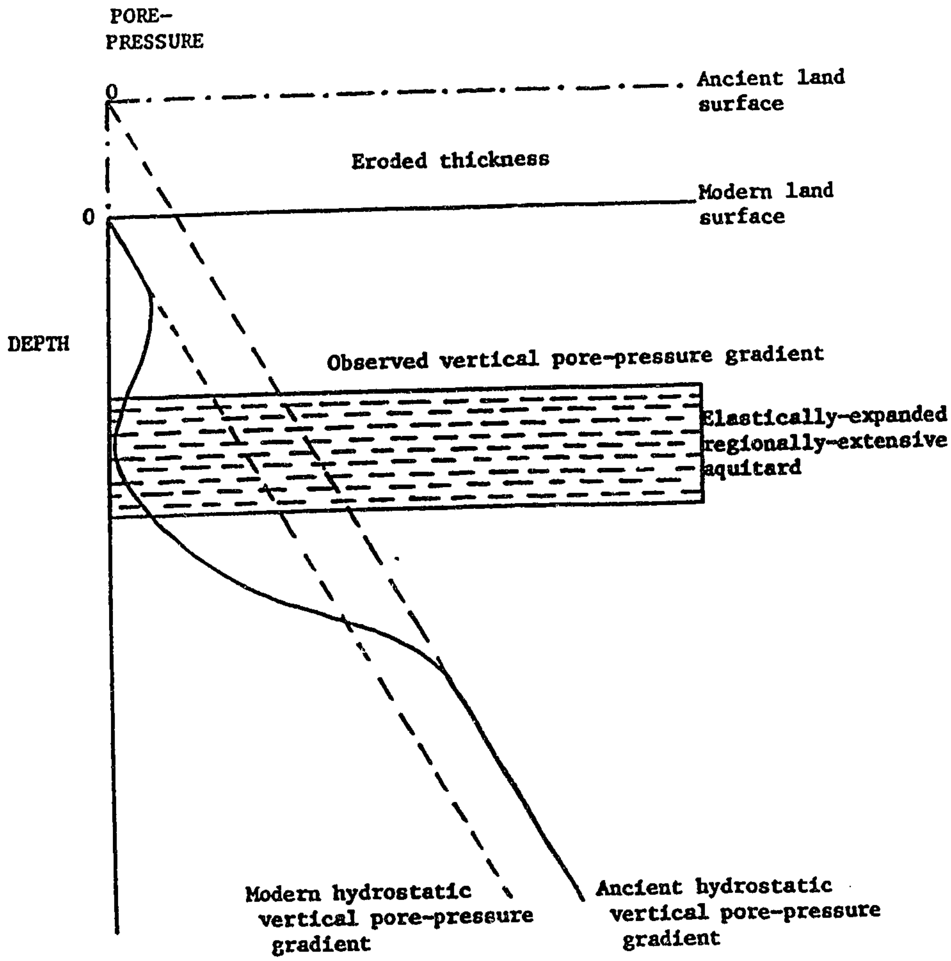


Figure 2.2c: Vertical distribution of pore-pressures at $t > 0$, some time after erosional event. Pore-pressure sink controls pore-pressure distribution in over and underlying strata as well as within aquitard.

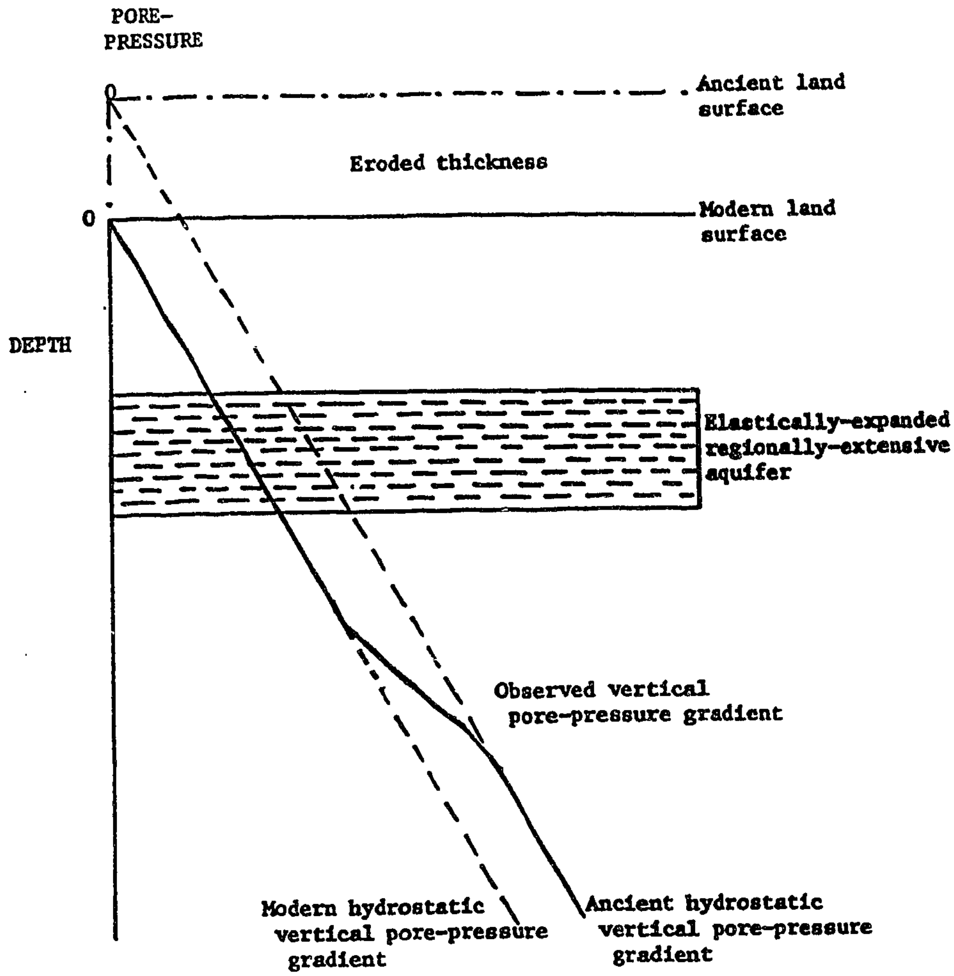


Figure 2.2d: Vertical pore-pressure distribution at $t \gg 0$, a long time after erosional event. Groundwater flow into the zone of dilated rock pores has caused the pore-pressure sink to decay away. Pore-pressures are adjusted to modern land-surface boundary-conditions except deep within the basin where the pore-pressures are only now beginning to equilibrate to the modern land-surface boundary-conditions.

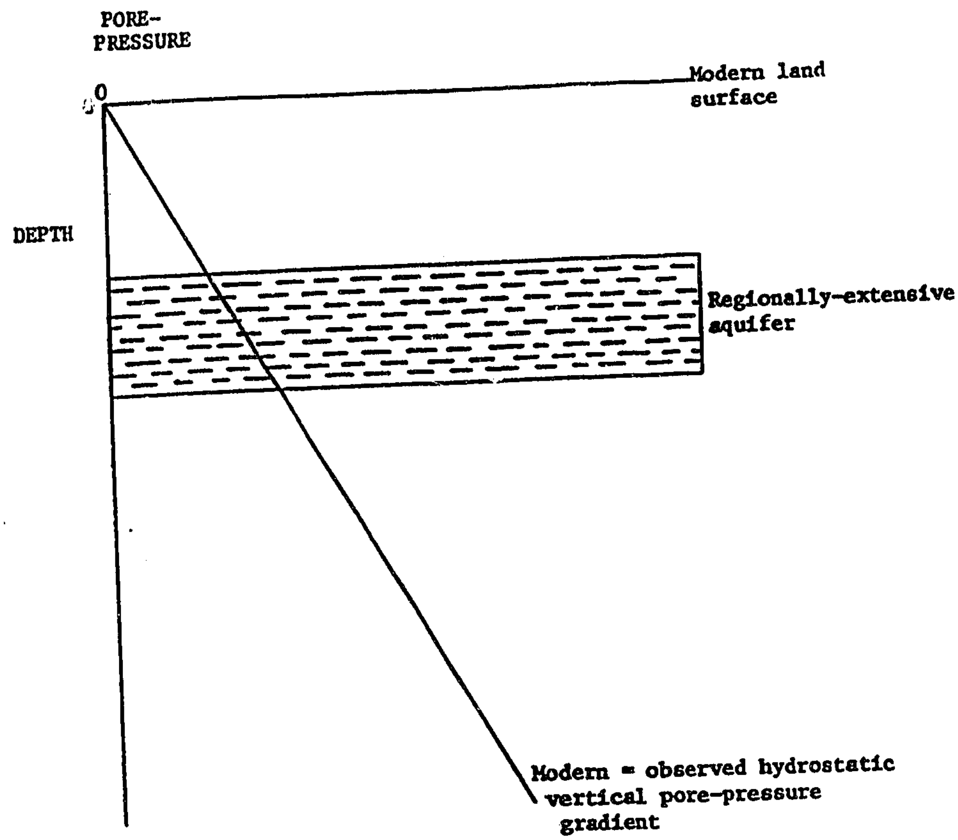


Figure 2.2e: Vertical pore-pressure distribution at $t=+\infty$ Pore-pressures are in equilibrium with modern land surface boundary conditions.

2.3 Field Study

2.3.1 Location and Physiography of Study Area

The study area is located approximately 100 kilometers southwest of Edmonton in west-central Alberta, at approximately 52° 50' N latitude and 114° 45' W longitude, Dominion Land Survey Coordinates: T45 R6 and R7 W5M (Figure 2.3). This places it south of Buck Lake, Alberta and southeast of the giant Pembina (Cardium Formation) oil pool. The area was selected because an examination of the areal distribution of Belly River Formation drillstem tests, a source of subsurface pressure data, indicated that this area had potentially enough data to procede with this study.

The study area is part of the Western Alberta High Plains, characterized by rolling, hilly topography. It lies 60 kilometers east of the Brazeau Thrust Fault, which separates the High Plains from the Foothills region. The climate is humid continental and the area is drained on the surface by the North Saskatchewan River System (Tokarsky, 1971). The region is blanketed by a veneer of glacial till less than 15 m thick. The modern topography essentially replicates the bedrock topography. Numerous buried pre-glacial valleys exist in the area, most of which manifest themselves as topographic depressions on the modern land surface (Carlson, 1970).

2.3.2 Geology

The study area is located on the east limb of the Alberta syncline which forms the Alberta Basin, itself a component of the larger Western Canadian Sedimentary Basin. There are over 3000 meters of Phanerozoic sediments overlying the Pre-Cambrian (Hudsonian) crystalline basement (Burwash et al.,1964). The Phanerozoic sediments consist of approximately 1000 meters of Paleozoic carbonates and shales overlain by 2000 meters of Mesozoic and Cenozoic clastic

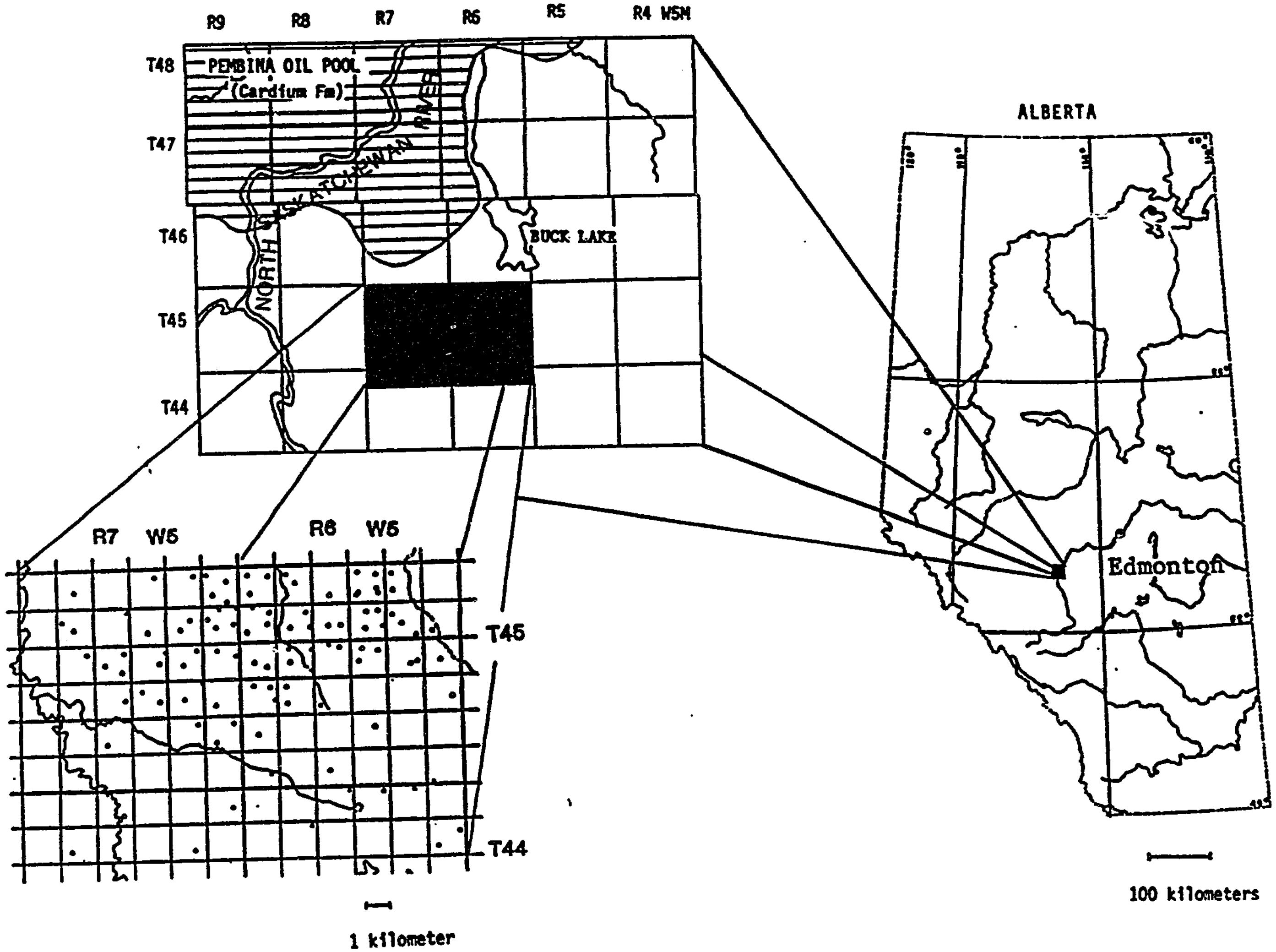


Figure 2.3: Location of study area.

deposits. This study is concerned only with those Cretaceous and Tertiary sediments comprising the upper 1500 meters of the stratigraphic column. The strata of interest in this study, namely the Upper Cretaceous Lea Park, Belly River, Bearpaw and Edmonton Formations, the Upper Cretaceous-Tertiary Paskapoo Formation and the Quarternary till blanket, are shown in Figure 2.4.

The Lea Park Formation is a marine shale, 130 m thick in the study area. It was deposited in an epiric sea during early Campanian time (Williams and Burk, 1964). On electric logs it is recognized by its consistently high gamma-ray trace. The upper contact with the overlying Belly River Formation is conformable and recognized on logs only by a gradual increase in sand content. On a regional scale, the Lea Park can be considered to be an aquitard.

The Belly River Formation is a heterogeneous formation comprising often lenticular conglomerates and sandstones interbedded with siltstones, coals, shales and mudstones. It is 275 meters thick in the study area. It represents the progradation of continental conditions into the Alberta Basin which followed the eastward and southward withdrawal of the Lea Park Sea during Campanian time. This marine regression was caused by uplift to the west associated with the Laramide Orogeny (Stott, 1984). Environments of deposition include shoreline, deltaic and fluvio-continental, their co-existence in the formation being due to its diachronous nature becoming younger as well as more marine to the east (Shouldice, 1979). The Belly River Formation sandstones and conglomerates are common targets for oil and gas exploration. Further to the east, they are also regarded as potential sources of groundwater (Tokarsky, 1971). On the regional scale, the Belly River Formation is considered to be an aquifer.

The Bearpaw Formation is a marine shale which was widely deposited over the southern part of the Alberta Basin following deposition of the Belly River Formation. In the study area, the Bearpaw Formation is close to its northwest depositional edge (Williams and Burk, 1964) and is only about 40 meters thick. Where it thins to zero, the underlying Belly River Formation becomes indistinguishable from the overlying Edmonton Formation and the two are

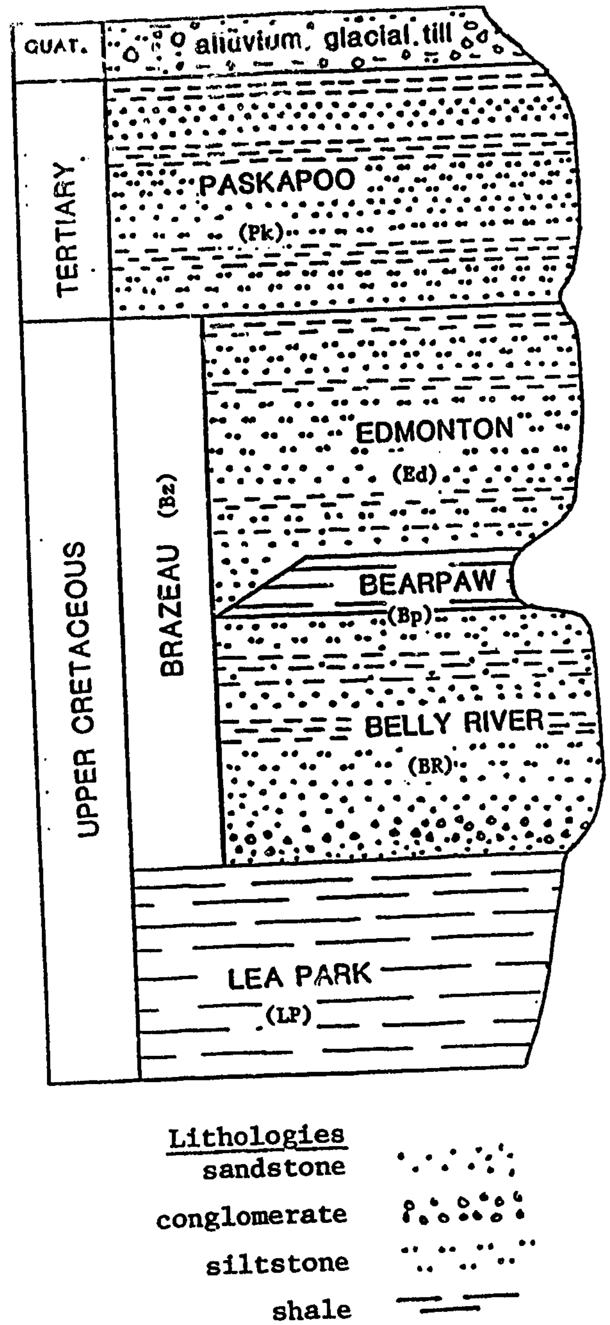


Figure 2.4: Principal stratigraphy, Upper Cretaceous and Tertiary of west-central Alberta.

amalgamated into one unit called the Brazeau Formation (Stott, 1963). On a regional scale, the Bearpaw is considered to be an aquitard.

The Edmonton Formation, approximately 600 m thick in the study area, includes all Upper Cretaceous beds which are equivalent in age to or younger than the Bearpaw Formation (Williams and Burk,1964). It consists of gradationally interbedded bentonitic sandstones, siltstones, shales and coals which were deposited under continental conditions and were derived from the lands uplifted to the west (Douglas et al., 1976).

The Edmonton Formation is overlain by the Upper Cretaceous to Tertiary Paskapoo Formation, again a continental clastic sequence of sandstones, siltstones, shales and coals. It is 480 m thick in the study area. The Paskapoo Formation is the only outcropping formation in the general area east of the Brazeau Thrust, being exposed along the banks of the Brazeau and North Saskatchewan Rivers and subcropping beneath the thin layer of Quaternary-age till which blankets the region. Sands of the Paskapoo Formation are commonly used by landowners as aquifers in this area (Tokarsky, 1971). Because of their comparable bulk hydraulic properties, the Edmonton Formation and the Paskapoo Formation can be considered to be a single aquifer on the regional scale.

The sequence from the Lea Park to the top of the Paskapoo is considered to be a conformable sequence, though there is evidence for the existence of an erosional unconformity between the Edmonton and Paskapoo formations elsewhere in the province of Alberta (Irish, 1970; Douglas et al., 1976). The eroded surface at the top of the bedrock marks a major unconformity. It has been established from the study of coal ranks in the Alberta Basin that over 2000 meters of Paskapoo sediments have been eroded since the mid-Tertiary (Hacquebard, 1977). In the study area itself, it is estimated that 2250 meters have been removed (Hitchon, 1984). The time of the commencement of this erosion has been estimated as being late Eocene to early Oligocene time, coinciding with the maximum pulse of the Laramide Orogeny. From this time to the present, the entire Alberta Basin has been uplifted and undergoing subaerial erosion.

Rock Mechanical Properties of Upper Cretaceous and Tertiary Rock

In a detailed study, Locker (1973) described the rock mechanical properties of the rocks and sediments of Upper Cretaceous and Tertiary age in central Alberta. From samples taken from core and outcrop, Locker determined that the bulk of these formations comprises silt and clay size particles. Since fine-grained particles, particularly the clays and micas, can store strain energy when distorted by compressive stresses, Locker concluded that there existed a considerable amount of such energy available for elastic rebound and volumetric expansion of the rock framework following the removal of great thicknesses of overburden since the mid-Tertiary. Locker gave experimental evidence based on actual rock samples to support this conclusion. He also cited the widespread occurence of fissuring in surface exposures as field evidence that this rebound actually occurred.

Locker concluded that the main controls on elastic rebound in the Upper Cretaceous and Tertiary rocks of central Alberta are:

1. amount of overburden removal, which increases to the west;
2. lithology, especially montmorillonite which augments rebound and whose proportion in these rocks increases to the east;
3. degree of consolidation and diagenesis which increases to the west and with depth and generally reduces the rebound effect.

The interactions of these controls are very complicated and difficult, if not impossible to quantify.

2.3.3 Vertical Pore-Pressure Relationships

Data

All drillstem test charts and reports for T44 and T45, Ranges 6 and 7 W5M were obtained (Energy Resources Conservation Board, 1988a). First, those DST's which were taken in the Belly River Formation were selected. Then the charts were screened visually for technical quality and obvious misruns were removed from the data set. The remaining DST's were analysed using Horner analysis (Horner, 1951). Of the analysed DST's, 46 had Horner buildup-curves which could be extrapolated to a formation pressure. These 46 DST's are listed in Table 2.1. The mechanical error in the data used has been minimized by the initial screening of the data. For DST's which used an electronic gauge, the pressures can be considered accurate to 3.44 kPa (0.5 psi) (Lynes United Services, date unknown). DST's with mechanical chart recorders are less accurate. They can be considered accurate to 0.02 of their total range and read to 0.25 mm (0.001") with a chart reader (Lynes United Services, date unknown). For this study, a typical chart will be accurate to within 90 kPa of true value. Since care has been taken to take only the best quality tests in this study, a mechanical accuracy of +/- 100 kPa will be accepted.

Vertical Pore-Pressure Relationships in the Belly River Formation

The DST-derived formation pressures were plotted versus the depth and versus the elevation of the pressure recorder, creating a pressure-depth (p(d)) diagram and a pressure-elevation (p(z)) diagram, respectively. For further discussion of pressure-depth diagrams, the reader is referred to Orr and Kreitler (1985) and to Tóth (1978). For a discussion of pressure-elevation diagrams, see Dahlberg (1982, p.53).

The two diagrams, shown in Figures 2.5 and 2.6, illustrate the vertical pore-pressure distribution in the Belly River Formation in the study area. For reference, the depths and elevations of the formation tops taken from a well drilled at 8-13-45-6 W5M are displayed on the diagrams. From the two diagrams, three things can be observed. First, all the pressures scatter around a single gradient. Second, the vertical pore-pressure gradients are superhydrostatic. Third, the pore-pressures are subhydrostatic.

The first observation indicates that the Belly River Formation is hydraulically continuous. From relative permeability curves, it appears that the Belly River Formation is water-wet (Hunter, 1966). Thus water is free to move

Well Location	Year	K.B. Elev.	DST Top	DST Bttm.	Rec. Depth	Rec. Elev.	Horner-plot	Fluid
		(m)	Depth (m)	Depth (m)	(m)	(m)	Pmax (kPa)	Recovered
15-35-44-6W5	78	990.3	1315	1319	1317	-327	9225	water
7-33-44-7W5	77	916.5	1083	1109	1104	-188	6012	water
8-6-45-6W5	87	988.2	1342	1370	1349	-361	9830	water
5-16-45-6W5	78	984	1323	1335	1325	-341	9540	mud
5-16-45-6W5	78	984	1114	1126	1116	-132	6275	mud
6-17-45-6W5	83	981.7	1337	1342	1339	-357	9410	mud
8-18-45-6W5	83	975.7	1332	1339	1334	-358	9470	oil
14-18-45-6W5	82	975	1337	1345	1339	-364	9630	mud
16-18-45-6W5	85	956.8	1300	1320	1301	-344	9388	con
14-20-45-6W5	82	931	1263	1287	1264	-333	9500	mud
14-21-45-6W5	83	934.2	1168	1175	1170	-236	7200	mud
15-21-45-6W5	81	933.6	1188	1192	1189	-255	7629	water
8-23-45-6W5	84	923	1217	1231	1219	-296	9295	mud
6-27-45-6W5	83	915.7	1063	1076	1065	-149	6380	water
8-29-45-6W5	82	927.4	1176	1181	1177	-250	7740	mud
16-29-45-6W5	83	931.8	1157	1167	1159	-227	7980	mud
16-30-45-6W5	80	920.45	1154	1168	1168	-248	7880	water
6-31-45-6W5	79	929	1251	1263	1255	-326	9345	gas
14-31-45-6W5	79	922.7	1146	1157	1148	-225	7840	mud
14-31-45-6W5	79	922.7	1238	1254	1241	-318	9436	mud
10-32-45-6W5	73	920.8	1055	1065	1059	-138	6205	mud
14-32-45-6W5	83	916.4	1227	1239	1229	-313	9255	mud
6-33-45-6W5	84	932	1268	1278	1270	-338	9690	mud
5-35-45-6W5	79	903.5	1051	1059	1052	-149	8200	mud
5-35-45-6W5	79	903.5	1060	1062	1061	-158	8455	mud
6-9-45-7W5	86	908.8	1294	1315	1296	-387	9710	water
6-9-45-7W5	86	908.8	1254	1275	1256	-347	9460	mud
16-14-45-7W5	85	970.1	1314	1330	1316	-346	9483	mud

Table 2.1: Belly River Formation Drillstem Tests

16-14-45-7W5	85	970.1	1428	1455	1431	-461	15190	mud
6-21-45-7W5	84	917.3	1286	1297	1288	-371	9372	mud
6-21-45-7W5	84	917.3	1204	1215	1206	-289	7883	mud
16-21-45-7W5	83	930.6	1228	1240	1230	-299	7897	water
16-21-45-7W5	83	930.6	1219	1225	1221	-290	7925	water
6-23-45-7W5	83	971.6	1262	1272	1263	-291	7935	water
16-23-45-7W5	82	982	1165	1170	1166	-184	6794	mud
16-23-45-7W5	82	982	1230	1235	1231	-249	7890	mud
9-24-45-7W5	82	957	1305	1313	1309	-352	9620	water
9-24-45-7W5	82	957	1227	1233	1217	-260	7675	mud
14-25-45-7W5	85	968.4	1296	1315	1300	-332	9481	water
6-29-45-7W5	81	924.6	1223	1233	1225	-300	7949	mud
6-29-45-7W5	81	924.6	1112	1122	1114	-189	6751	mud
14-31-45-7W5	79	922.7	1238	124	1241	-318	9340	mud
14-31-45-7W5	79	922.7	1146	1157	1148	-225	7869	mud
15-35-45-7W5	79	934.5	1053	1082	1054	-120	6014	mud
15-35-45-7W5	79	934.5	1148	1182	1149	-215	7186	mud
15-35-45-7W5	79	934.5	1208	1217	1209	-275	8145	mud
6-36-45-7W5	79	972.6	1292	1310	1294	-321	9097	mud

Table 2.1 (continued)

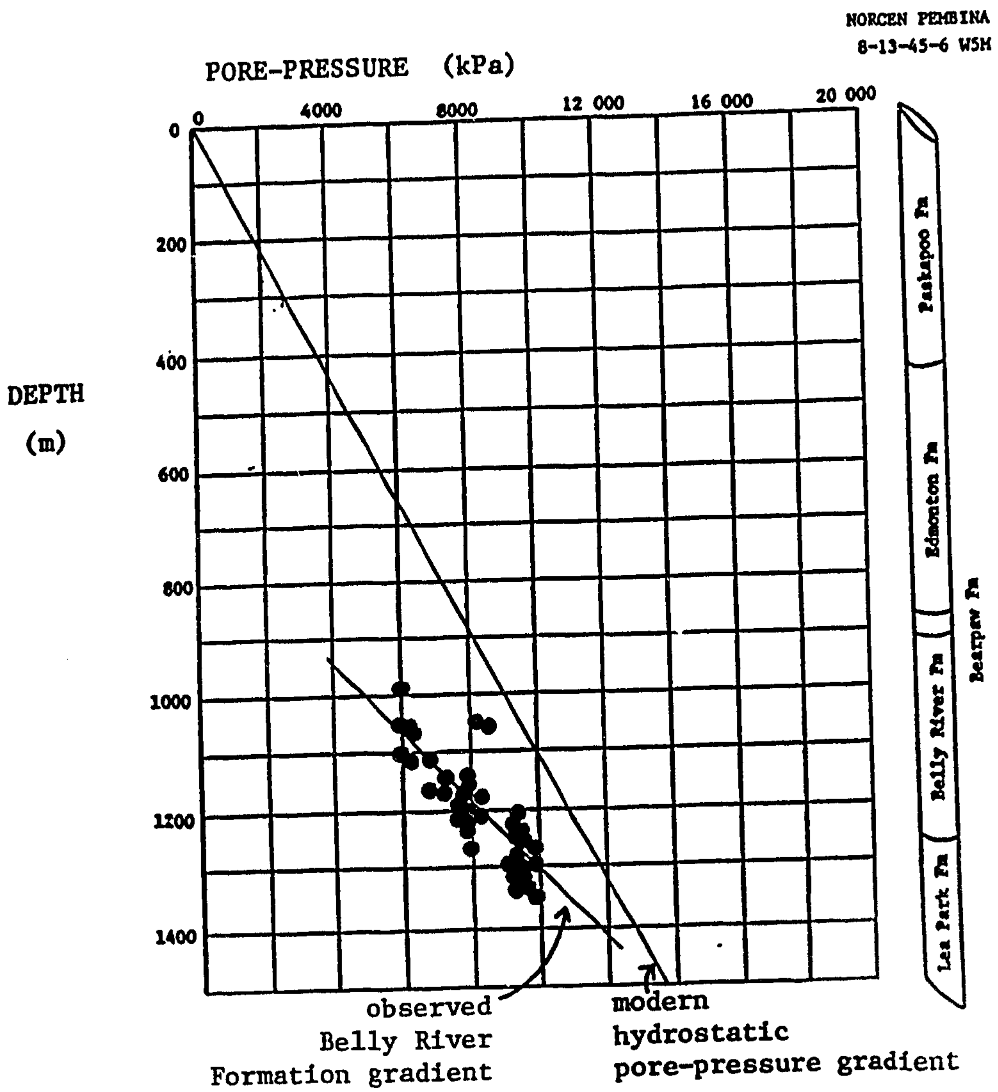


Figure 2.5: Pressure-depth diagram for Belly River Formation DST-derived pore-pressures.

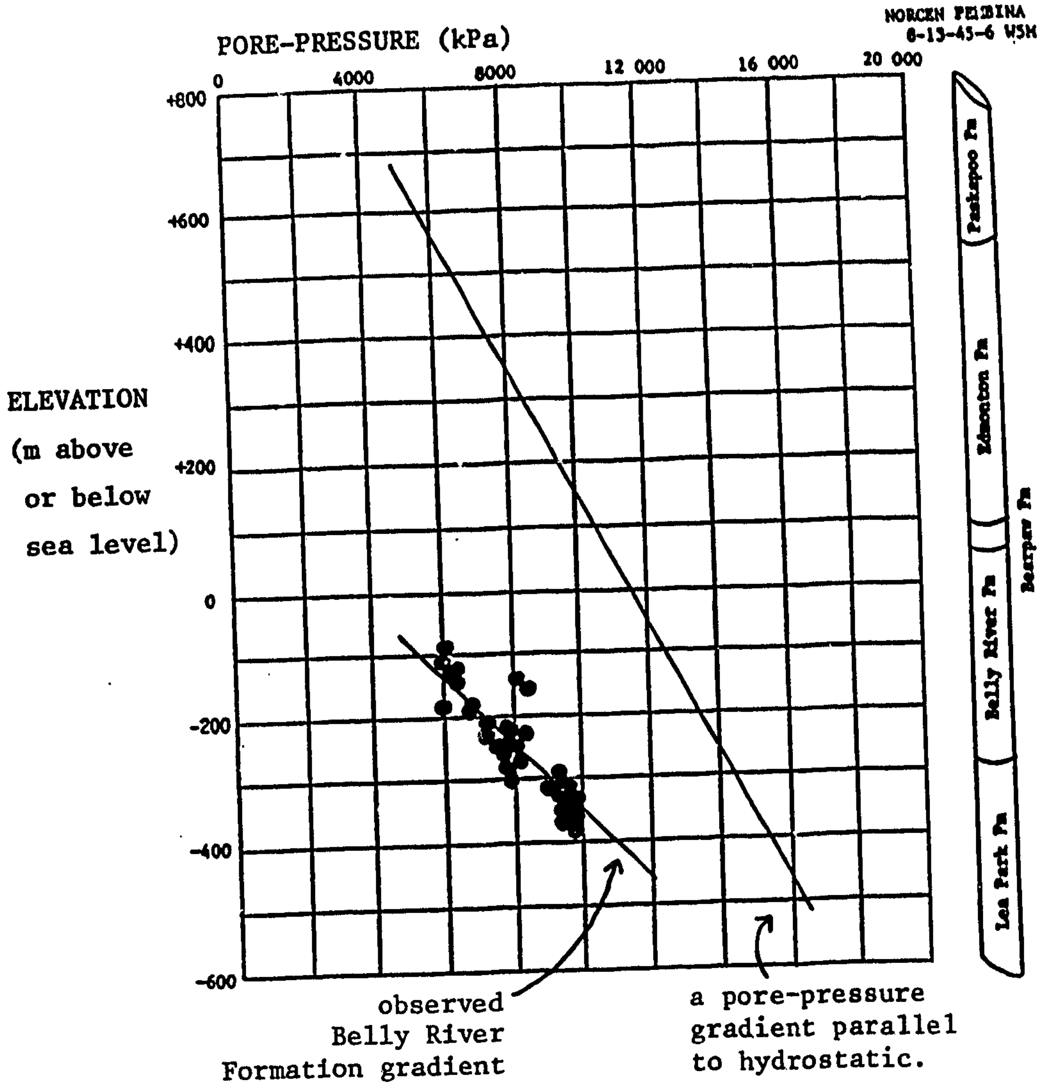


Figure 2.6: Pressure-elevation diagram for Belly River Formation DST-derived pore-pressures.

cross-formationally.

The superhydrostatic pore-pressure gradient was initially suspected to result from a fluid density greater than that of fresh water. The observed Belly River vertical pore-pressure gradient is approximately 15 kPa/m on the p(d) diagram whereas the fresh water hydrostatic gradient is 9.8 kPa/m. To determine if the superhydrostatic gradient is a function of high fluid density, the fluid composition of Belly River formation waters was examined. All water analyses from samples taken in the Belly River Formation in and around the study area were obtained (Energy Resources Conservation Board, 1988a). Only those analyses taken from DST's with a water recovery were chosen. These analyses had to meet the following criteria meant to screen out drilling-fluid contaminated samples (J.Thompson, person. comm.; 1987):

- pH in range from 6 to 8: >8 meant mud contamination
  <6 meant acid contamination.
- Na:Cl ratio close to 1:1
- [CO_3] <40 000 mg/l, greater meant possible mud contamination.

Twenty-four water analyses passed the screening (Table 2.2). Of these, the calculated total dissolved solids content ranged from 2308 mg/l to 24 499 mg/l. The mean TDS of these water samples is 7287 mg/l, indicating that the Belly River Formation waters are fresh. The superhydrostatic vertical pore-pressure gradient can, therefore, not be a consequence of high formation water density.

The third observation is that the pore-pressures are subhydrostatic in magniutude. For instance, the pressure obtained in the well at 8-18-45-6 W5M (Table 2.1) at a depth of 1334 m is 9470 kPa. From Equation 2.1, assuming ρ = 1000 kg/m, fluid pressure at this depth should be 13082 kPa. This example shows how underpressured the Belly River Formation is in the study area.

One way to explain the pore-pressure magnitudes and gradients observed in the Belly River Formation is to invoke the presence of an outcrop. If the formation is highly permeable and has good hydraulic communication with the outcrop as well as

Sampled Well Location	DST Interval Depth (m)	Relative Density of Formation Water	Formation Water pH	Total Dissolved Solids (mg/l)
4-34-44-4 W5M	1147-1152.5	1.000	7.9	3886
16-33-44-5 W5M	1270-1283	1.006	8.3	8278
6-24-44-6 W5M	1340-1364.5	1.008	7.9	12497
10-12-44-8 W5M	1474-1502	1.010	7.3	12603
2-19-44-8 W5M	1271-1306	1.010	7.85	12558
6-36-45-4 W5M	1225-1260	1.009	8.1	12436
4-1-45-6 W5M	1298-1305	1.007	8.26	10100
14-21-45-6 W5M	1186-1192	1.002	8.2	4416
15-21-45-6 W5M	1188-1192	1.002	7.9	5225
6-22-45-6 W5M	1170-1172.5	1.001	8.4	5000
6-27-45-6 W5M	1063-1076	1.002	8.3	2973
6-29-45-6 W5M	1042-1048	1.002	7.4	3171
16-21-45-7 W5M	1228-1240	1.002	8	4693
6-23-45-7 W5M	1262-1272	1.003	8.3	4501
6-25-45-7 W5M	1305-1215	1.009	7.7	24499
15-35-45-7 W5M	1053-1082	1.002	7.8	2308
6-36-45-7 W5M	1311-1328	1.009	8.3	9464
8-28-47-4 W5M	835.5-840	1.004	8.73	5820
12-3-47-5 W5M	1142-1154	1.011	8.2	14453
6-1-47-6 W5M	898 (RFT)	1.006	8.1	2645
6-1-47-6 W5M	981 (RFT)	1.006	8.4	3892
8-2-47-7 W5M	1031-1060	1.004	8.4	2356
2-4-47-7 W5M	1118-1121	1.009	7.52	4190
14-15-47-7 W5M	BHS	1.005	7.52	2930
			Average TDS =	7287 mg/l

Table 2.2: Belly River Formation Formation Water Analyses

being confined beneath strata of low permeability, then the pressures may equalize to the elevation of the outcrop. In this manner, subhydrostatic pore-pressures may be generated if the outcrop is located at an elevation lower than the overlying land surface. This is the mechanism by which subhydrostatic pore-pressures are generated in the Red Earth area of the Alberta Basin (Tóth, 1978). The pore-pressures in the Belly River Formation may be subhydrostatic because an outcrop of the Belly River Formation has been exposed and the outcrop elevation is lower than the land surface in the study area. This hypothesis predicts that an outcrop exists and there is lateral flow towards the outcrop.

The Belly River erosional edge subcrops beneath the Pleistocene drift several hundred kilometers to the east (Alberta Geological Survey, 1972). These subcrops are at lower elevations than the study area. It is not possible that subhydrostatic pore-pressures are generated by eastward flow to this subcrop edge because a potentiometric surface map of the lower Belly River Formation in the study area (Figure 2.7) shows a hydraulic heads decreasing from east to west. Lateral flow of groundwater in the Belly River Formation is towards the west, not to the east. This fact eliminates flow to the eastern subcrop as a possible cause of the subhydrostatic pore-pressures. Therefore, this hypothesis is rejected.

A second hypothesis formulated to explain the observed pore-pressure distribution was based on the model of regional gravity-driven groundwater flow. In regional groundwater flow systems, areas of regional discharge are characterized by superhydrostatic vertical pore-pressure gradients (Tóth, 1978). As such a gradient is observed in the study area, it was hypothesized that the observed pore-pressure distributions were a manifestation of regional groundwater discharge. However, this hypothesis offers no explanation of the subhydrostatic magnitudes of the observed pore pressures. Since it is logically impossible to have a superhydrostatic vertical pore-pressure gradient extending downwards from the water table generating subhydrostatic pore-pressure magnitudes, this hypothesis was rejected.

To show this another way, a water-table elevation map was generated from non-pumping water levels recorded on domestic water well and seismic shot-hole

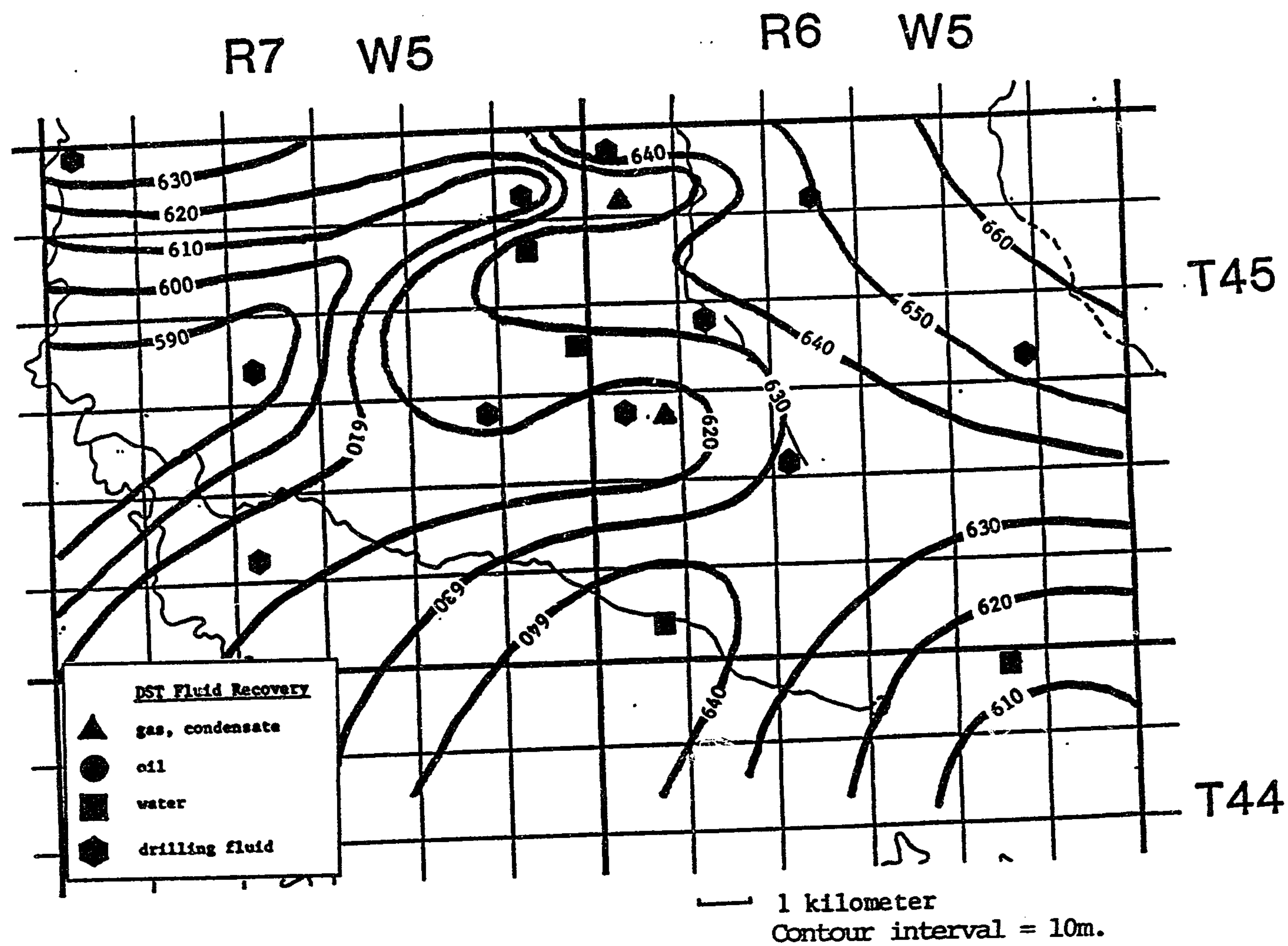


Figure 2.7: Water-potentiometric map, Lower Belly River Formation.

reports (Alberta Environment, 1988). The hydraulic heads in these shallow wells equal the water-table elevation in the wells. The hydraulic heads are in the range of 900 to 950 meters (Figure 2.8). Figure 2.7 shows that the lower Belly River hydraulic heads in the study area range from 600 to 650 meters. As water moves only from high hydraulic head to low, there can be no discharge from the Belly River Formation to the surface. This observation further supports the rejection of the second hypothesis.

A third hypothesis which could explain the observed pore-pressure magnitudes and gradients in the Belly River Formation can be stated as follows. Due to erosional unloading, elastic expansion of the fine-grained rock framework in the Edmonton and/or Paskapoo Formations has led to dilation of pore spaces. The low permeability of the shales and clays in these formations retards the passage of water into these pores so a zone of subhydrostatic pore-pressures is created. This pore-pressure sink is drawing in water from below, generating the superhydrostatic pore-pressure gradient in the Belly River Formation and in turn causing the Belly River pore-pressures to become subhydrostatic in magnitude.

To see if this zone exists, pore-pressure data for the Edmonton and Paskapoo Formations in the area were obtained. DST's in the Paskapoo and Edmonton Formations (and one from the Lea Park Formation) with Horner-extrapolatable formation pressures were obtained (Energy Resource Conservation Board, 1988b; Table 2.3; Figure 2.9). These were plotted on a p(d) diagram (Figure 2.10) and a p(z) diagram (Figure 2.11) with the Belly River Formation pressure data. The two diagrams show the same pattern, although the scatter of data on the p(z) diagram is not as pronounced as on the p(d) diagram. The reason for the difference in data scatter is that the p(d) diagram is affected by topographic variations, whereas the p(z) diagram is not so affected.

The fact that the data on the p(d) diagram is being affected by topographic variations is important. If the groundwater is in equilibrium with the land-surface boundary conditions, the data plotted on a p(d) diagram will have less scatter than on a p(z) diagram. The fact that the opposite is observed means that some process or

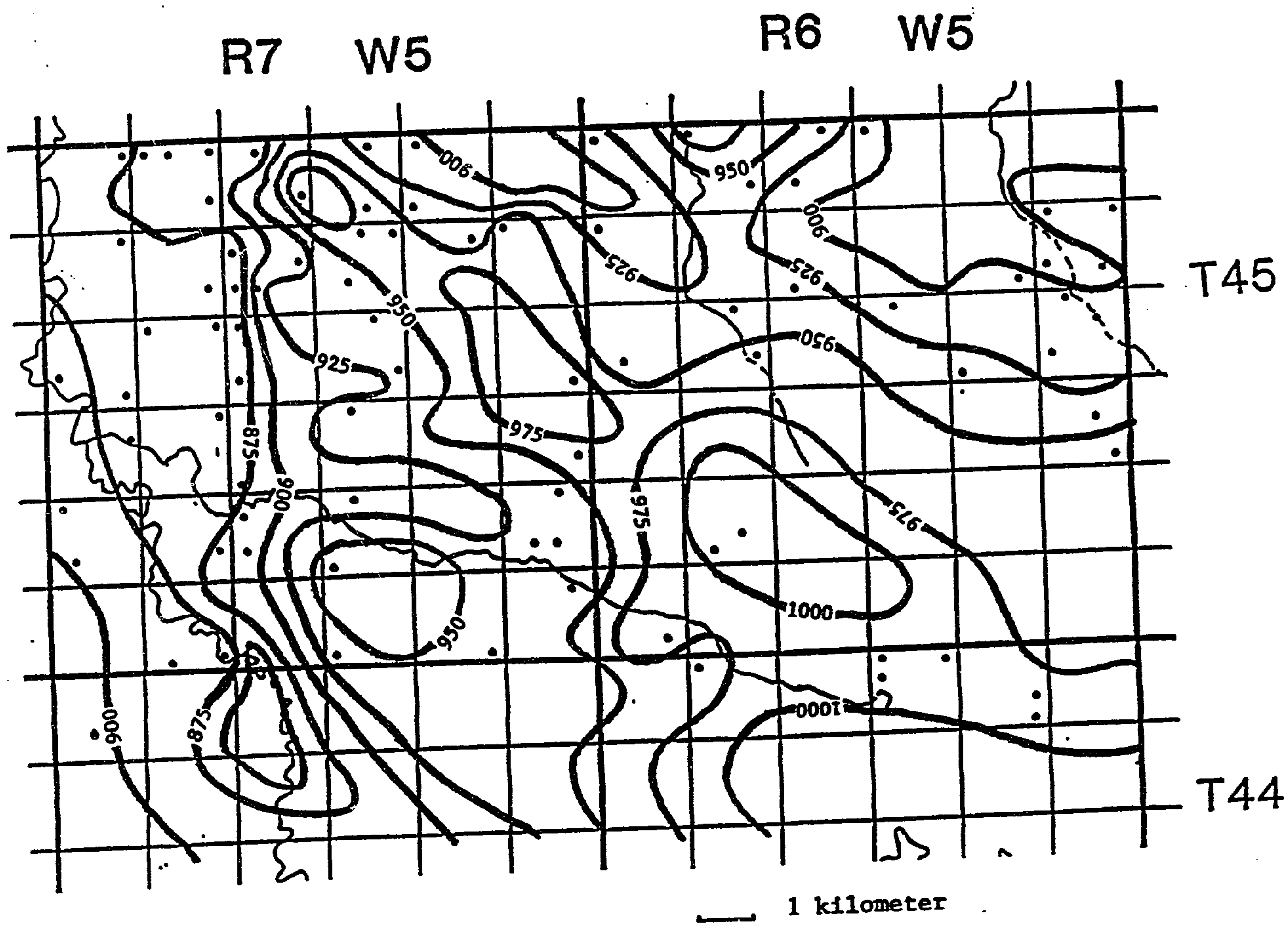


Figure 2.8: Water-table elevation map. Contour interval = 25m.

Well Location	Year	K.B. Elev.	DST Top	DST Bttm.	Rec. Depth	Rec. Elev.	Horner Plot	Fluid
		(m)	Depth (m)	Depth (m)	(m)	(m)	Pmax (kPa)	Recovered
11-1-44-8 W5	79	1017	574	591	577.5	439.5	1529.9	mud
16-14-45-7W5	85	970.1	1428	1455	1431	-461	15190	mud
6-28-45-8 W5	81	953	996.5	1008	998.5	-45.5	3365.16	mud
10-33-46-5 W5	78	946	658	671	660	286	1505	mud
12-33-45-6 W5	71	894	179	217	182	713	1101	water
12-33-45-6 W5	71	894	279	308	282	613	2201.8	water
12-33-45-6 W5	71	894	985	996	987	-92	6060.6	water
12-33-45-6 W5	71	894	305	316	306	588	2415	water
12-33-45-6 W5	71	894	277	288	279	615	2187	water
7-7-46-7 W5	81	888.3	800	806.5	801	88	1829	mud
11-7-47-5 W5	77	931	720	732	723	208	1875.4	mud
10-13-47-5 W5	79	881.6	665	679	668	214	2518	water

Table 2.3: Upper Cretaceous and Tertiary Drillstem Tests
Conducted in Strata Above the Belly River Formation
in the Edmonton and Paskapoo Formations.

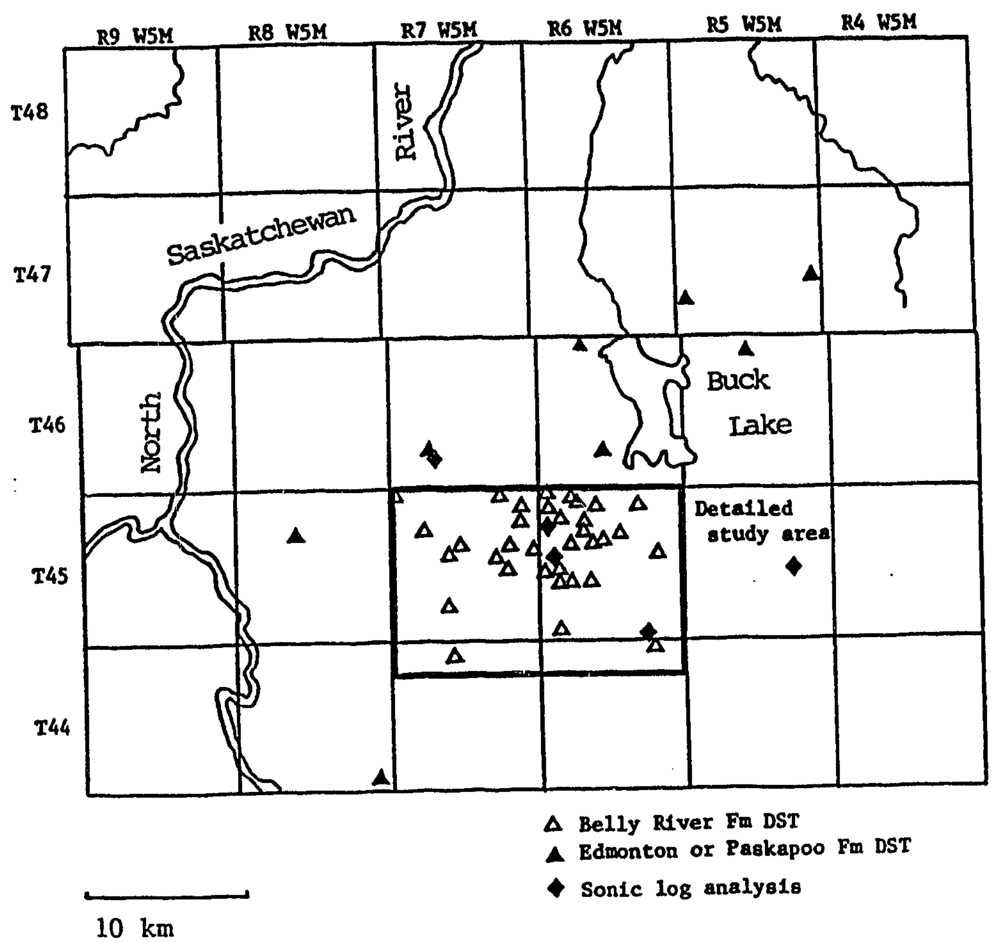


Figure 2.9: Location map for wells with DST's and sonic logs used in this study.

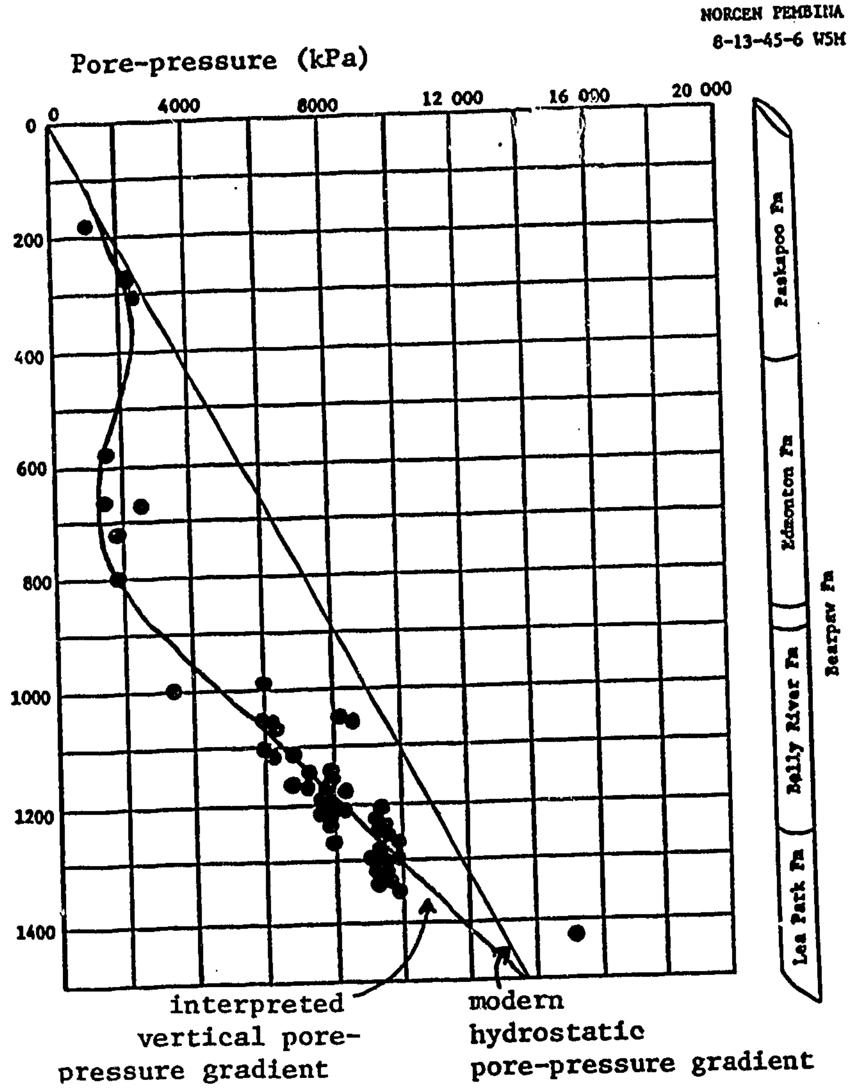


Figure 2.10: Pressure-depth diagram for DST-derived pore-pressures from the Belly River Formation plus DST-derived pore-pressures from the Lea Park, Edmonton and Paskapoo Formations.

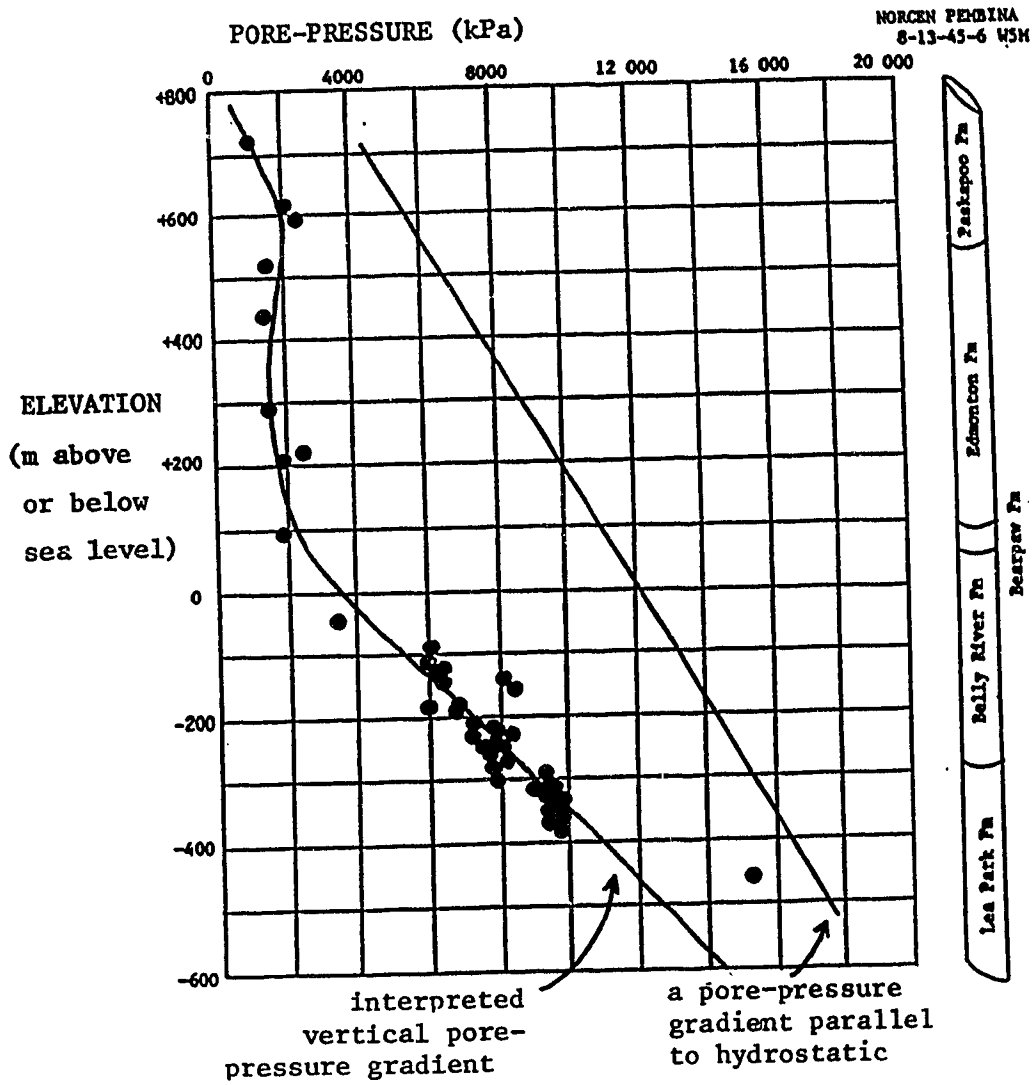


Figure 2.11: Pressure-elevation diagram for DST-derived pore-pressures from the Belly River Formation plus DST-derived pore-pressures from the Lea Park, Edmonton and Paskapoo Formations.

phenomenon is interfering with the hydraulic communication betweem the strata of interest and the land surface.

The new p(d) diagram shows the pore-pressures to be most subhydrostatic in the lower Edmonton Formation, at 600-800 meters depth below the land surface, and returning to near-hydrostatic in the Paskapoo Formation. If a p(d) gradient is interpreted from the data, one can see it bears a very close resemblance to the vertical pore-pressure gradient examined in Figure 2.2c. This gives strong support to the hypothesis that a zone of dilated pores is generating a pore-pressure sink above the Belly River Formation.

The one pore-pressure measurement from the Lea Park Formation is superhydrostatic. This can be explained as the consequence of the superhydrostatic vertical pore-pressure gradient crossing the modern hydrostatic gradient deeper below the pore-pressure sink, as shown in Figure 2.2c.

Geology provides further supporting evidence of this conclusion. In areas where undercompacted shales are found, their presence can be documented using sonic logs (Fertl,1976). The use of sonic logs to document the presence of undercompacted shales is based on the observation that in a sedimentary column deposited under uninterrupted conditions, the shale porosity decreases with depth at an exponential rate. As the travel time of a sonic pulse through the rock is exponentially related to porosity, a plot of sonic travel-time through shale versus depth of burial should yield a linear relationship, provided the deposition was continuous and there is no change in the acoustic properties of the shales with depth. Any shales which are undercompacted relative to depth of burial will show up as departures of their sonic travel-times from the linear relationship when plotted on a graph of sonic travel-time versus depth. Since the fine-grained rock of Upper Cretaceous and Tertiary age are suspected to be the most susceptible to pore-dilation, this technique was applied to shales in the study area to look for evidence of this phenomenon.

Sonic travel-times from five wells (see Figure 2.9 for locations) were recorded for shales at approximately every twenty-five meter increase in depth from end of surface casing to below the Lea Park Shale. In interbedded zones, shales were recognized by their high gamma-ray count (>75 API units) and spontaneous potentials near or at the shale base line established for each well. To avoid effects caused by well caving, only the sonic travel-times in shale intervals that were near or at drilled hole-diameter on the caliper log were recorded. The sonic travel-times versus depth were plotted for each well (Figures 2.12a to 2.12e).

All of the wells show a linear trend of sonic travel-time through shales with depth. The wells also show anomalous scatter of sonic travel-time through shales towards higher values in a zone centered around 400-600 m below the land surface, indicating that this is a zone where shales tend to have higher than expected porosities. This corresponds to the Upper Edmonton Formation. It can be interpreted that the zone where shales have higher than expected porosities is a zone of pore-dilation.

The lack of vertical coincidence of the pore-pressure anomalies and the shale porosity anomalies in the Edmonton Formation can be explained as a manifestation of the complex interactions of pore-dilation and pore-pressures in the elastic-expansion process. The high shale travel-times in the Upper Edmonton Formation may be indicative of expansion which has already happened. The pore-pressures are not as anomalously low as in the Lower Edmonton Formation because water has already been able to enter into the pore spaces to re-pressurize the Upper Edmonton Formation. In the Lower Edmonton Formation, on the other hand, pore-pressures have been substantially reduced because of the rock framework expansion but the expected increase in porosity has not developed to the same degree as in the Upper Edmonton Formation.

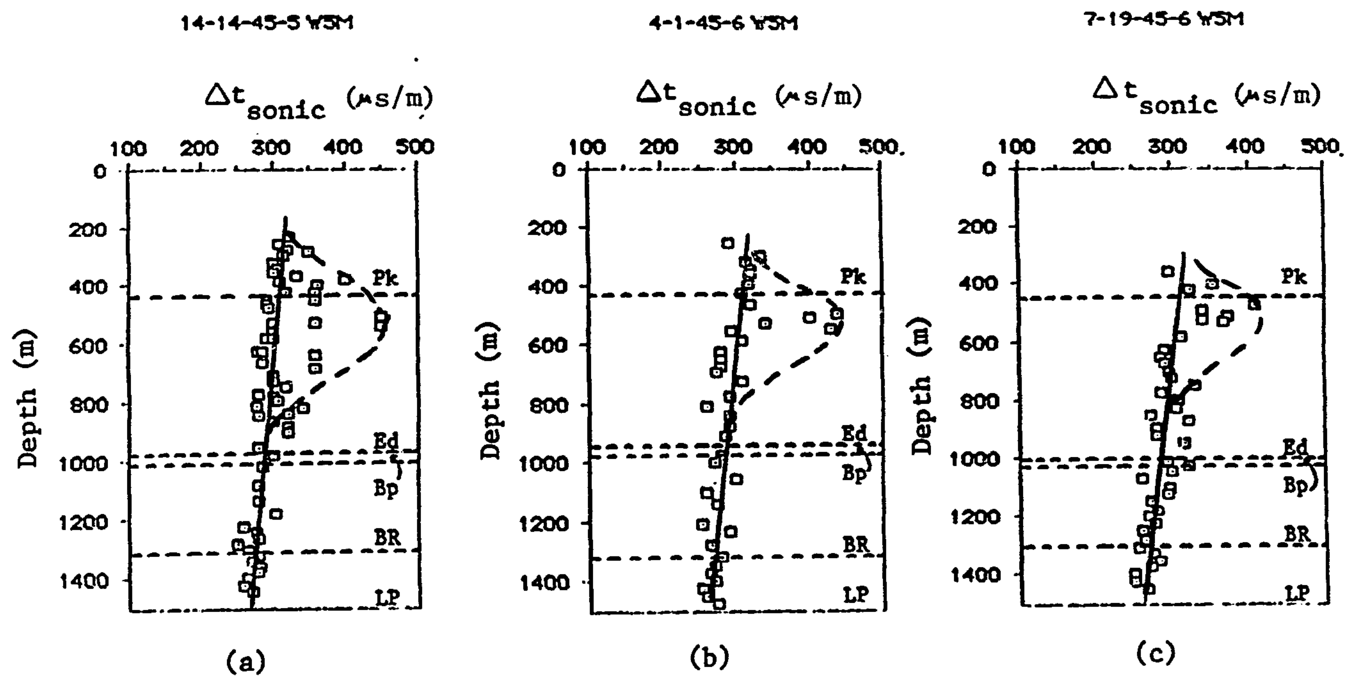


Figure 2.12: Sonic travel-time through shale versus depth in selected wells. Heavy line marks linear trend with depth; dashed line outlines zones of anomalously high sonic travel-times.

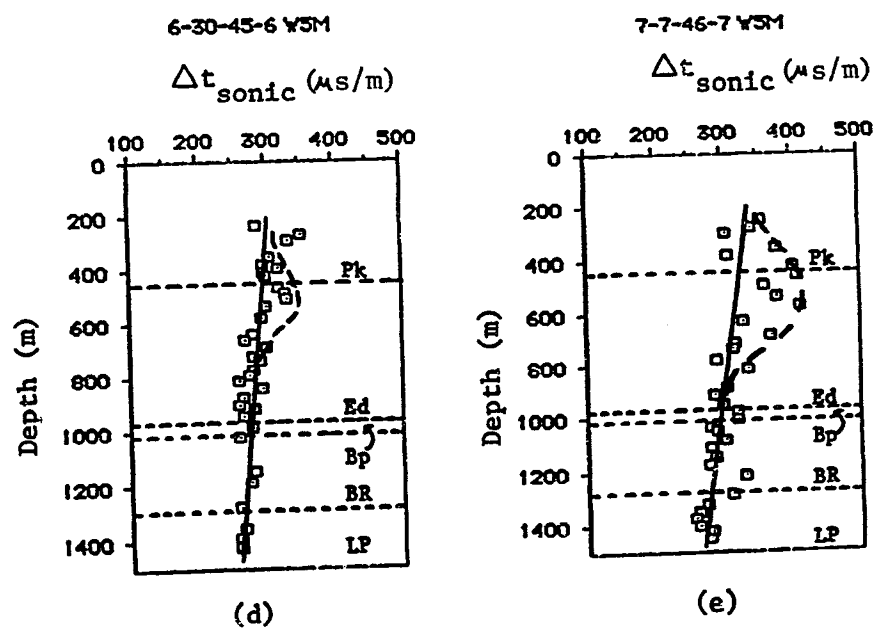


Figure 2.12: (continued)

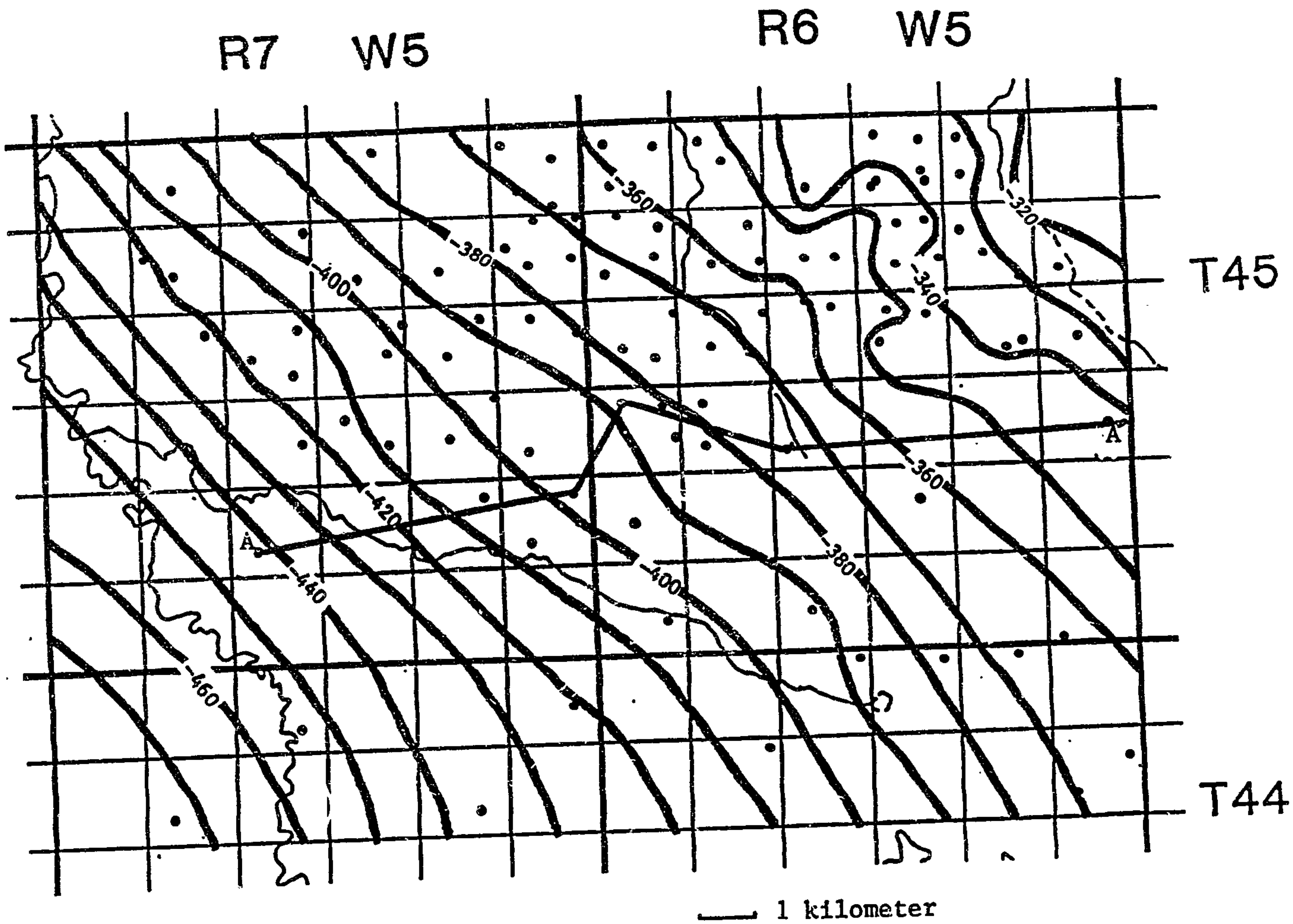


Figure 3.6: Structure, Top of Lea Park Formation. Contour interval = 10m.

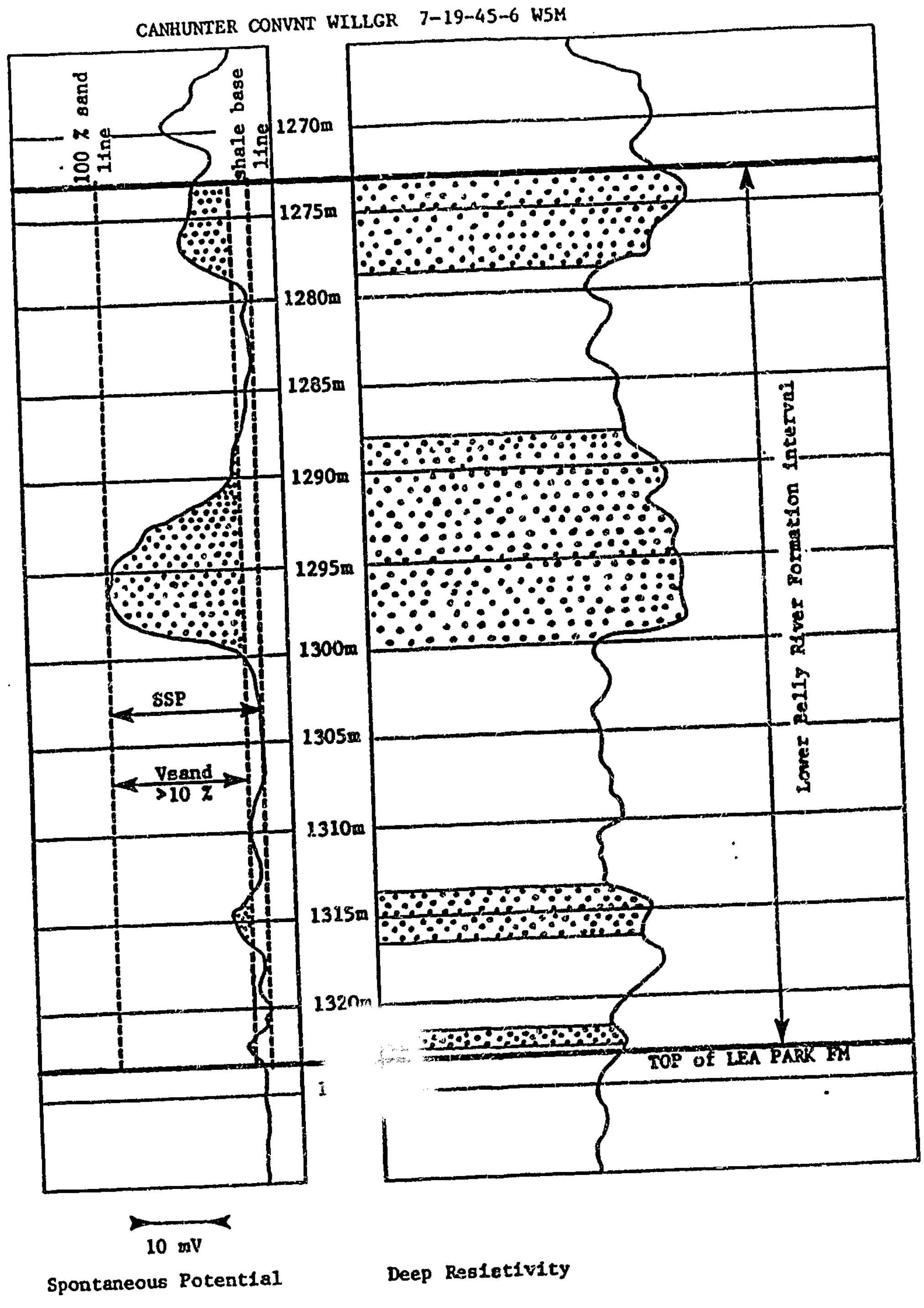
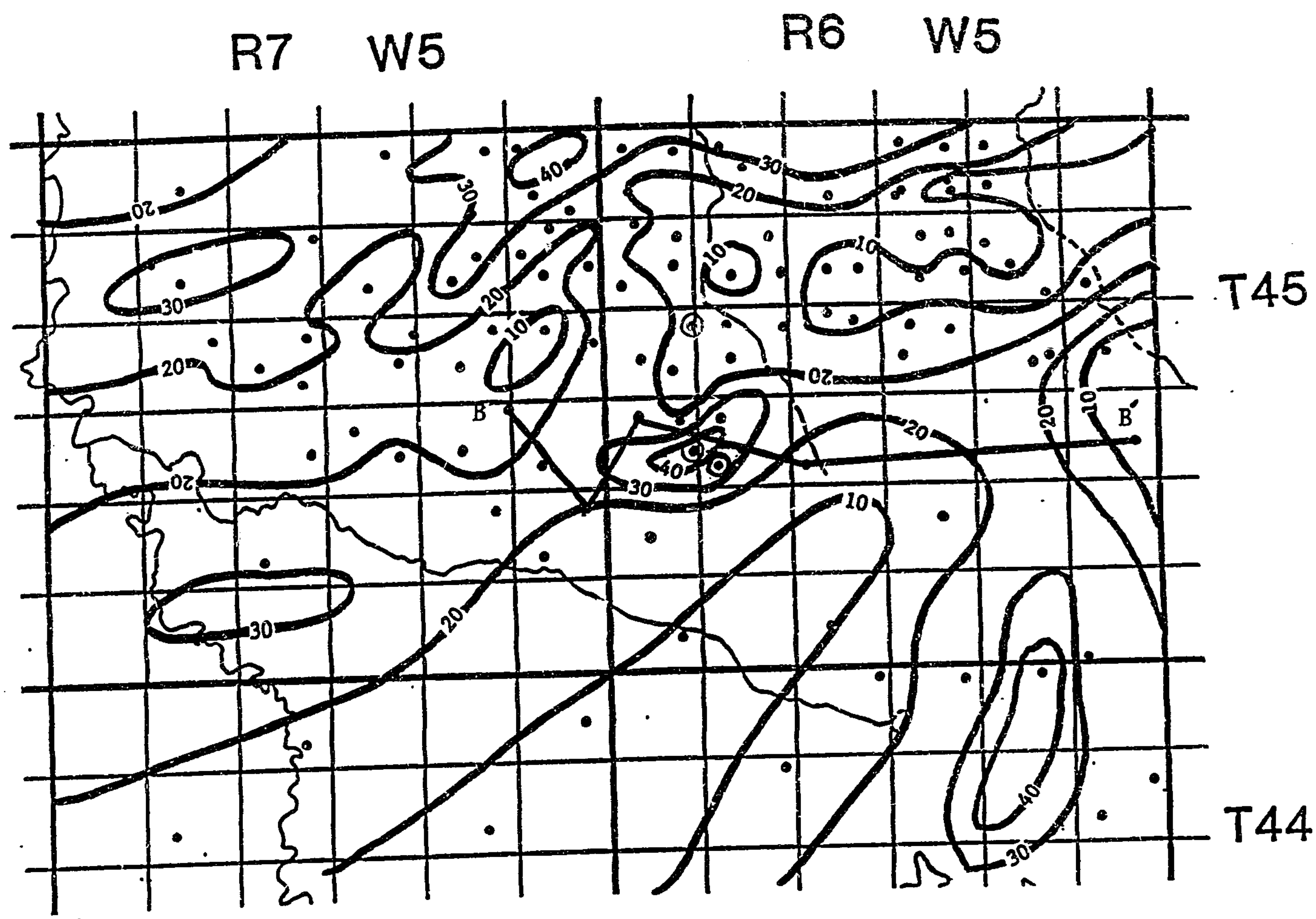


Figure 3.7: Electric-log signatures for lower Belly River Formation in a well in the study area illustrating criteria for defining "sand" from E-logs.



1 kilometer

lower Belly River core examined for this study

Figure 3.8: Isopach of cumulative sand in lower Belly River Formation. Contour interval = 10m.

the interval of interest includes all the Belly River Formation from the top of the Lea Park Formation to 50 meters above the contact as determined from electric logs. These sands will hereafter be called the lower Belly River Formation.

The contact between the Lea Park Formation and the Belly River Formation is conformable and gradational (Iawuagwu and Lerbekmo, 1984). On a regional scale, the two formations interdigitate (Nichols and Wyman, 1969). In the study area, the top of the Lea Park Formation was picked as the base of the first significant development of sand as recognized on spontaneous potential (SP) and resistivity (R_d) logs taken from petroleum exploration boreholes (Figure 3.5). The structure on the top of the Lea Park Formation is shown on Figure 3.6. The surface dips monoclinally to the southwest with a dip direction and dip of 215° 0.4 °. To ensure that the top of the Lea Park could be used as a stratigraphic marker, the total thickness between the top of the Lea Park Formation and a marker bed in the Lea Park Formation was mapped. No significant variation in the thickness was observed over the study area, indicating that there is little scour or structure on the Lea Park Formation which would preclude using the top of the Lea Park Formation as a marker horizon.

The total sand thickness for the lower 50 meters of the Belly River Formation in each borehole was recorded. Sand was defined on the SP log for each borehole as any deflection away from the shale base line which was greater than 0.10 times the apparent magnitude of the static spontaneous potential (SSP) in that borehole. SSP was defined for each borehole's SP log as the greatest observed deflection from the shale base line in the Belly River Formation (Figure 3.7).

An isopach map of total sand in the lower Belly River Formation is shown in Figure 3.8. It reveals a pattern of west-to-east trending ribbons of thick sands. These sand ribbons intertwine, separating and coalescing in a complex three-dimensional network over the study area. The patterns that the sand ribbons make are typical of braided river-type fluvial deposits (Blatt, et al., 1980). The total sand thickness varies from less than 5 m to greater than 40 m. The thickest sands are localized within the intertwining ribbons of sand. These localized concentrations of sand impart a lenticular nature to the formation.

To clarify the nature of the sands further, several oil well cores in the area of one of the sand lenses (see Figure 3.8) were selected for study. The cores, such as the one illustrated in Figure 3.9, show that the lower Belly River sediments comprise interbedded coaly mudstones, coals, siltstones, fine-grained sandstones, medium to coarse-grained massive sandstones (sublitharenite) and grain-supported chert pebble conglomerates. Scour surfaces and rip-up clasts are frequently observed. In fine-grained sandstones, thin shale drapes make it possible to see low-angle unidirectional cross-bedding and climbing ripples. Soft-sediment deformation and large (> 10 cm) irregular block-shaped clasts are observed and are interpreted to be slumping features. The mudstone contains abundant woody-carbonaceous fragments. The sandstones and conglomerates are massive, homogeneous and well-sorted. Both cores and electric-log signatures show overall fining-upward sequences in the lower Belly River sandstone beds.

The cores indicate that the lower sands are fluvial in origin. The massive sandstones and conglomerates represent channel and channel lag deposits. The fine-grained sandstones and siltstones with the ripple marks and low-angle cross-bedding may be products of deposition on point-bars or in crevasse-splays. The coals and coaly mudstones represent levee, overbank and possibly oxbow-lake deposits. The interbedded nature of the deposits, the rip-up clasts, the scoured surfaces and the slump features attest to the oscillatory lateral meandering of the channels that deposited the lower Belly River Formation sands and gravels. The lack of fine-grained sediments and the interbedded nature of the massive conglomerates and sandstones support the interpretation that these sediments were deposited in braided streams.

Permeability Distribution

The spatial distribution of the permeability, k, of the rock framework must be characterized in order to understand local patterns in regional groundwater flow. One

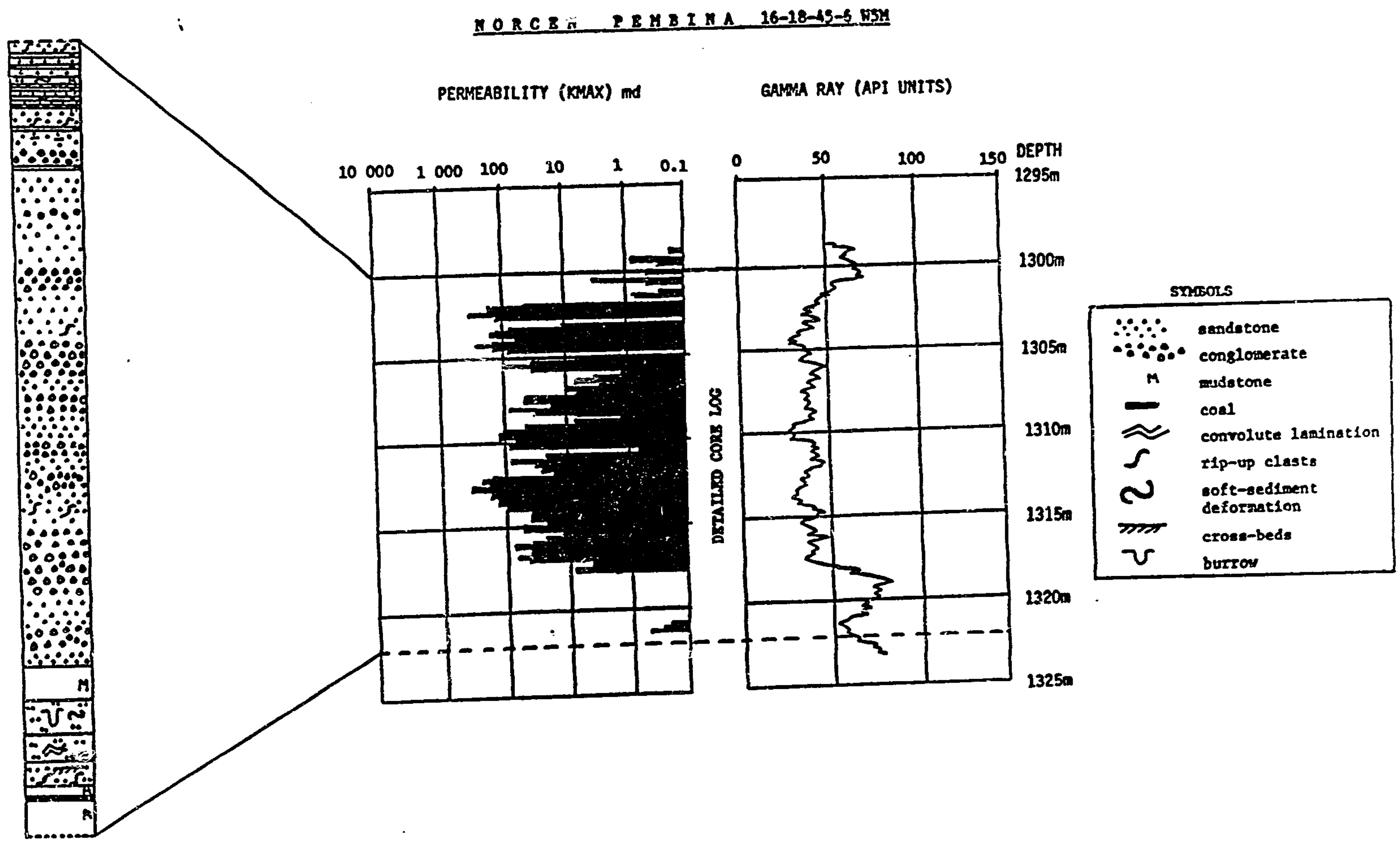


Figure 3.9: Illustration of lithology, permeability and gamma-ray log response in a lower Belly River Formation core taken in a thick sand lens in the study area.

way to characterize a regional permeability distribution is to use a geology-based approach. In a study of regional groundwater-flow through the Wilcox aquifer system in Texas (a formation very similar to the Belly River Formation in terms of sedimentology), Fogg (1986) faced the problem of how to characterize the permeability of rock volumes on a regional scale when the aquifers are not well defined layers but sand-body networks that are interconnected to varying degrees and for which there are few data on k available. Fogg characterized the permeability of the sands in the aquifer with a single value of k which was the arithmetic mean of the lognormal distribution of pump-test derived k values taken from channel sands.

The log transform of 16 DST-derived (Horner, 1951) permeabilities (Table 3.1) from Belly River sands from the study area were plotted on a histogram (Figure 3.10). A log transform was used because the distribution of permeability in nature is considered to be log-normal (Freeze, 1975). The distribution of the values is narrow and has an arithmetic mean value of 2.6×10^{-3} darcies.

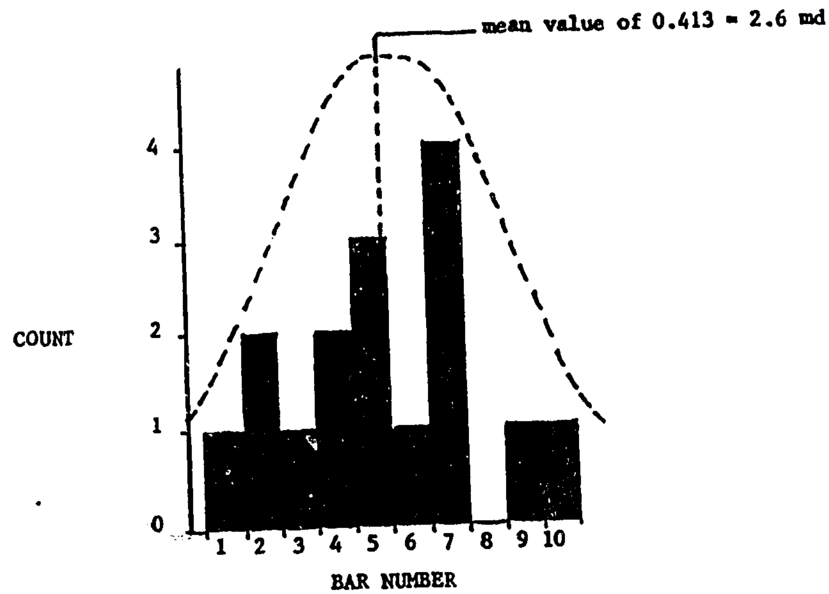
Routine analyses performed on cores taken in the area show that permeabilities can range from < 1×10^{-3} darcies to over 1 darcy (Energy Resources Conservation Board, 1988a). Some conglomeratic samples in the examined cores had measured permeabilities on the order of 10 darcies (Energy Resources Conservation Board, 1988a). Average core permeablilities in the channel deposits are on the order of, for example, 4.16×10^{-2} darcies, as in the case of the lower Belly River sands cored in the well at 16-18-45-6 W5M (Energy Resources Conservation Board, 1988a).

For several reasons, the value of average permeability derived from DST-data is regarded as being more representative than averages taken from core analyses. First, the DST is affected by the bulk properties of the rock: grain size, structure, lithology variations, anisotropy, bedding, etc. Second, the volume of rock tested by a DST is much larger than a core analysis. Third, the DST measures *in situ* permeabilities, whereas core analyses are done under surface conditions. These factors make the DST-derived average permeabilities more representative of regional permeabilities.

The assumption that the sands can be characterized by a single value of permeability implies that the spatial distribution of the permeability of the sands can

Well Location	DST Top Depth (m)	DST Bottom Depth (m)	Permeability (millidarcies)
15-35-44-6W5	1315	1319	11.6851
8-6-45-6W5	1342	1370	16.5906
5-16-45-6W5	1323	1335	1.309
6-17-45-6W5	1337	1342	15.1816
8-18-45-6W5	1332	1339	86.987
14-18-45-6W5	1337	1345	0.4901
14-20-45-6W5	1263	1287	15.2956
8-23-45-6W5	1217	1231	7.1616
6-31-45-6W5	1251	1263	0.1774
14-32-45-6W5	1227	1239	1.4809
6-33-45-6W5	1268	1278	0.1889
6-9-45-7W5	1294	1315	0.281
16-14-45-7W5	1314	1330	0.8723
[illegible]-25-45-7W5	1296	1315	294.24
4-[illegible]-45-7W5	1238	124	2.0905
6-[illegible]-45-7W5	1292	1310	0.0306

Table 3.1: Lower Belly River Formation permeabilities derived from drillstem tests.



Bar Number	From: (log k)	To: (log k)	Count
1	-1.514	-1.116	1
2	-1.116	-0.717	2
3	-0.717	-0.319	1
4	-0.319	-0.079	2
5	0.079	0.478	3
6	0.478	0.876	1
7	0.876	1.275	4
8	1.275	1.673	0
9	1.673	2.071	1
10	2.071	2.47	1

Figure 3.10: Histogram of log transform of DST-derived permeabilities of lower Belly River Formation from Table 3.1.

be inferred from the sand isopach map. In confined aquifers, the flow of groundwater is controlled by transmissivity, which is the permeability times the thickness. If it is assumed that the lower Belly River sands are laterally interconnected enough to behave as a confined aquifer, then the sand isopach map represents a transmissivity map of the lower Belly River sands.

Re-examining the lower Belly River Formation sand isopach map (Figure 3.8) in this light allows us to describe this interval's permeability distribution over the study area. The lower Belly River Formation is characterized by variations of transmissivity from less than 1.1×10^{-3} darcy-m to over 1.0×10^{-2} darcy-m. If the thick sands tend to be associated with conglomerates having permeabilities over 1 darcy, then the lenses observed on the sand isopach map may have much higher transmissivities than can be inferred from the map. Since the conglomerates are indistinguishable from true sands on the electric logs, their control on the permeability distribution of the lower Belly River Formation in the study area cannot be quantified.

3.3.3 Analysis of Water Flow Patterns

Groundwater flow-patterns can be interpreted from potentiometric maps and vertical pore-pressure gradients. It is necessary to use as much information as possible in order to characterize the flow field in three-dimensions. The discussion below details efforts made to characterize the groundwater motion in the lower Belly River Formation in the study area.

Data

The data used in this section is a subset of the drillstem tests used in the first part of this thesis. Details of how the data were obtained and processed are on page 26. From the set of DST's used in the previous part, 20 were identified as lower Belly River Formation tests by comparing depths of the tested intervals with E-logs in their respective bore holes.The 20 DST's are listed in Table 3.2.

Well Location	Year	K.B.	DST Top	DST Bttm.	Recorder	Recorder	Horner-plot	Water	DST Fluid
		Elev.	Depth	Depth	Depth	Elevation	Pmax	Head	Recovery
		(m)	(m)	(m)	(m)	(m)	(kPa)	(m)	
15-35-44-6W5	78	990.3	1315	1319	1317	-327	9225	614	186m salt water
8-6-45-6W5	87	988.2	1342	1370	1349	-361	9830	642	780m water, 40m mud
5-16-45-6W5	78	984	1323	1335	1325	-341	9540	632	221m mud, 9m oil
6-17-45-6W5	83	981.7	1337	1342	1339	-357	9410	602	38m mud and condensate
8-18-45-6W5	83	975.7	1332	1339	1334	-358	9470	607	121m oil
14-18-45-6W5	82	975	1337	1345	1339	-364	9630	618	38m mud, 9m oil
16-18-45-6W5	85	956.8	1300	1320	1301	-344	9388	613	9m condensate
14-20-45-6W5	82	931	1263	1287	1264	-333	9500	636	78m mud
8-23-45-6W5	84	923	1217	1231	1219	-296	9295	652	38m mud
6-31-45-6W5	79	929	1251	1263	1255	-326	9345	627	gas to surface
14-31-45-6W5	79	922.7	1238	1254	1241	-318	9436	644	80m mud, 10m oil
14-32-45-6W5	83	916.4	1227	1239	1229	-313	9255	631	91m mud
6-33-45-6W5	84	932	1268	1278	1270	-338	9690	650	27m mud
6-9-45-7W5	86	908.8	1254	1275	1256	-347	9460	617	90m mud
16-14-45-7W5	85	970.1	1314	1330	1316	-346	9483	621	54m mud
6-21-45-7W5	84	917.3	1286	1297	1288	-371	9372	585	18m mud
9-24-45-7W5	82	957	1305	1313	1309	-352	9620	629	112m water
14-25-45-7W5	85	968.4	1296	1315	1300	-332	9481	635	305m water
14-31-45-7W5	79	922.7	1238	124	1241	-318	9340	634	38m mud
6-36-45-7W5	79	972.6	1292	1310	1294	-321	9097	606	36m mud

Table 3.2: Lower Belly River Formation Drillstem Tests

For this study, all DST's for which a pressure could be obtained through Horner analysis are included in the data set, regardless of type of fluid recovered. It is assumed that if a pressure is obtained, it is valid for the interval tested. Given the fact that there are DST's in the data set which had extrapolatable Horner-plots yet recovered mud and/or hydrocarbons rather than formation water, the question must be asked as to whether or not calculating water-hydraulic heads from these pressures is a valid procedure.

Mud recoveries in Belly River Formation DST's are common because the formation is subhydrostatically pressured. The weight of the mud column present in the borehole during drilling operations forces mud filtrate into the formation. During the preflow interval on the DST, the invading fluids are produced first. If the preflow time is insufficient to clear the zone of mud filtrate, then the recovery will be entirely mud and mud filtrate. If the zone was not tested on penetration, the radius of invasion around the borehole may be quite large and no amount of economically realistic preflow time will clear it entirely of mud. The fluid recovery will not invalidate the pressure obtained through the Horner analysis. Any overpressuring caused by the weight of the mud column will be eliminated during the preflow time drawdown, the pressure build-up in the DST test chamber will be controlled by the natural formation pressures. Since thirteen of the DST's used in this study had a mud recovery, acceptance of DST's with mud recoveries is critical.

In the case where hydrocarbon fluids were recovered, more careful consideration must be given to the meaning of the pressures obtained. In the lower Belly River Formation sands of the study area, log analysis has shown that the hydrocarbons are not density-stratified within reservoir sands (Figure 3.11). When this occurs, the water in t reservoir co-exists with the hydrocarbons in a three-dimensional network ..e water in these complex reservoirs is at the same pressure as the hydrocarbons and therefore, pressures obtained from DST's in these reservoirs are valid for the purposes of calculating hydraulic heads for water. Four of the DST's used in this study recovered hydrocarbons.

Another major concern in this study is production-induced pressure drawdown

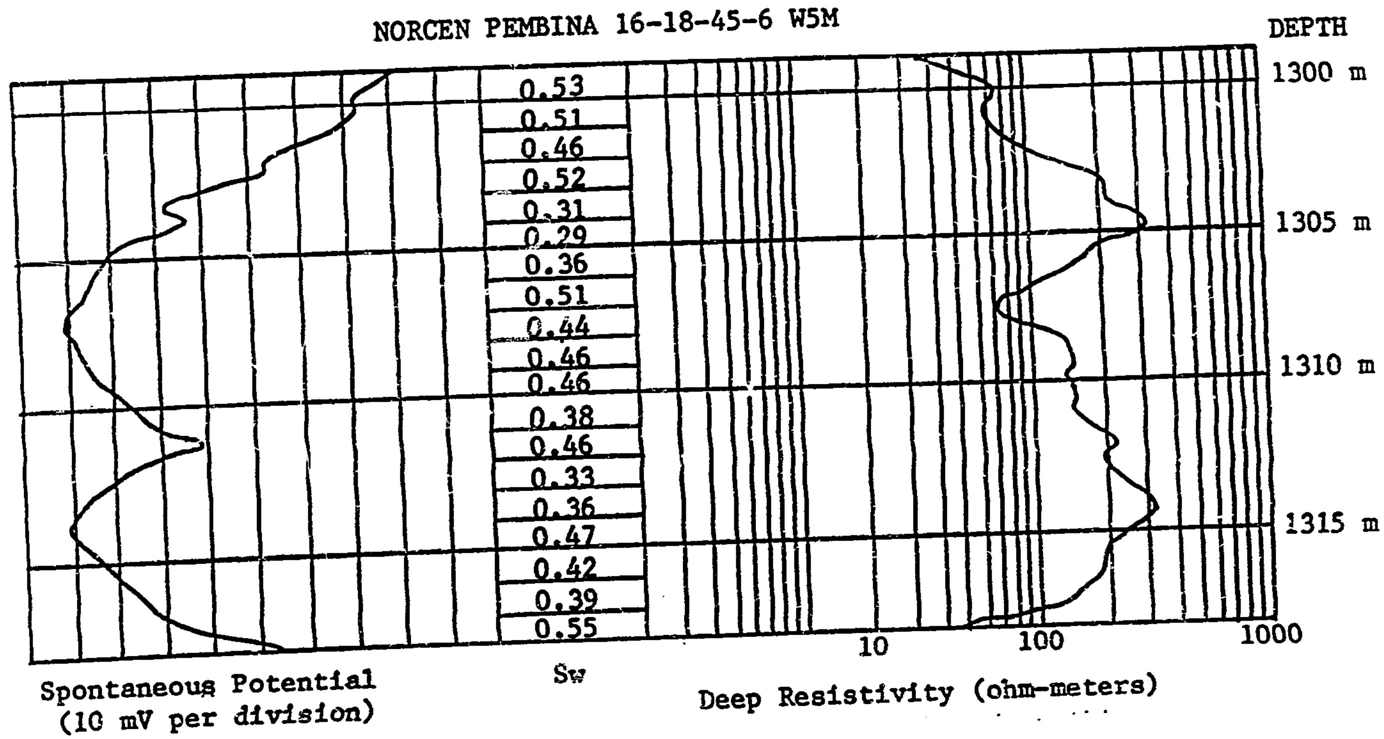


Figure 3.11: Vertical distribution of S_w, water saturation, in a lower Belly River Formation reservoir, assuming that $R_w = 0.24\Omega$-m.

(PIPD). PIPD generates fluid-potential anomalies on potentiometric surface maps unrelated to natural flow conditions (Bair et al., 1985).

One method to screen the DST-derived pressure data for PIPD is to use a pressure-elevation, or p(z), diagram as shown in Figure 3.12. If a system is static, all pressures will fall on a single vertical pore-pressure gradient on the p(z) diagram and PIPD can be recognized by pressures which do not plot on the gradient (see Dahlberg, 1982, p.66). If a system is dynamic, however, i.e., the fluids are in motion, then there will not be one single p(z) gradient for the reservoir but instead a distinct p(z) gradient for each point in the system. One can see on the p(z) diagram for the lower Belly River Formation (Figure 3.12) that the pore-pressures do not fall upon a distinct single p(z) gradient. As it has been established that the water in the Belly River Formation is in motion, the p(z) method cannot be used to screen out PIPD in this case and another method had to be used to screen for PIPD..

It was established previously that the DST-derived pressures are accurate within 100 kPa. This corresponds to approximately 10 meters of freshwater hydraulic head (Equations 3.1 and 3.2). For this study, it was decided that a pressure will be regarded as being affected by PIPD if it is derived from a DST which postdates nearby production or injection and whose associated hydraulic head differs from a nearby value of hydraulic head (which predates the production) by more than 10 meters. In the petroleum industry, it is generally accepted as a rule of thumb that a well can drain a reservoir for a 1.6 km radius. Therefore, a DST will be suspected of being influenced by production only if that production is within a 1.6 km radius of the tested well. Admittedly, this is a crude approximation but to refine the distance further would entail a complete reservoir geology and production history study which is beyond the scope of this work.

To visualize the time-distance relationships of the DST's and any fluid production from the lower Belly River Formation, a time-line was constructed (Figure 3.13). The DST's were plotted according to their dates of origin. From production records to March, 1988 (Energy Resources Conservation Board, 1988c) it was possible to determine from which wells there had been any production or

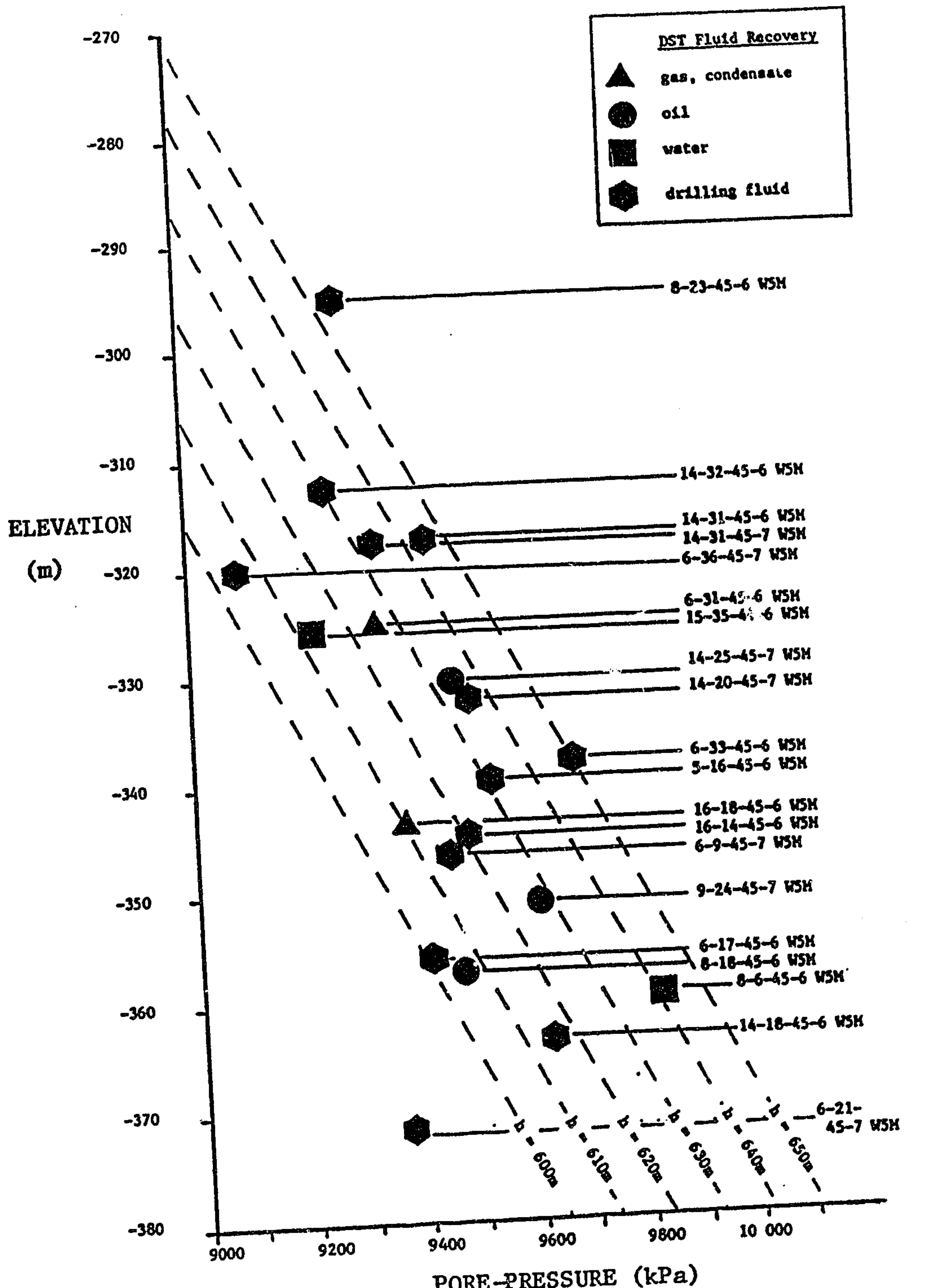


Figure 3.12: Pressure-elevation diagram for the Lower Belly River Formation in the study area.

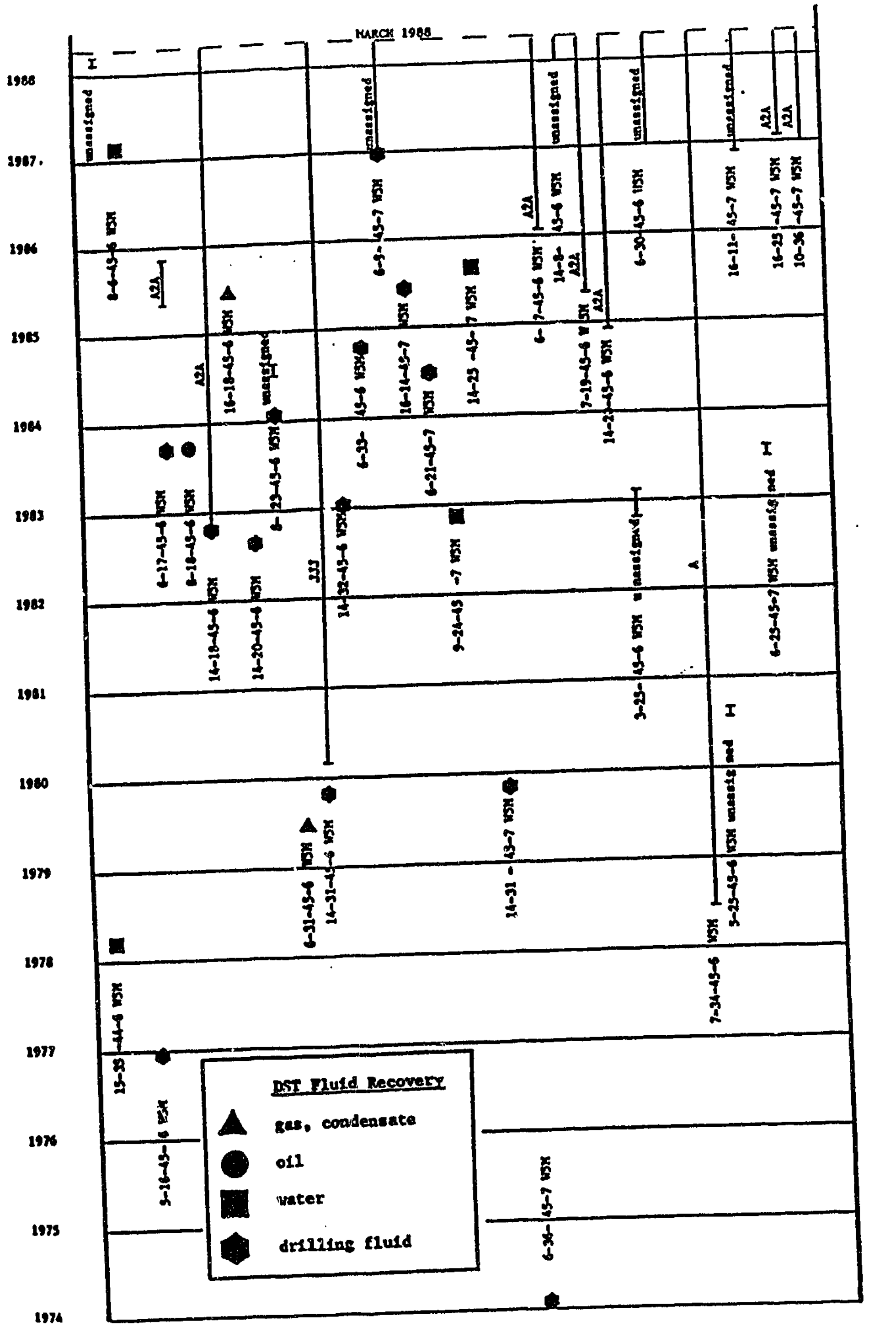


Figure 3.13: Time-line illustrating relative timing of lower Belly River Formation DSt's and production.

injection of fluids into the Belly River Formation. Then by comparing the depths at which the well was perforated as recorded on well records (Canadian Petroleum Information Exchange, 1987) and/or average depths of designated oil pools to which the wells were assigned (Energy Resources Conservation Board, 1986) to the depths of the lower Belly River Formation determined from well logs, those wells producing from the lower Belly River Formation interval were identified. The intervals of production were plotted on the time-line with the DST's.

Using the lines of 10 m hydraulic head increments on the p(z) diagram (Figure 3.11) and the production time-line (Figure 3.12) as a guide, pressures were removed from the data set if they postdated production by a well producing from the lower Belly River Formation within a 1.6 kilometer radius and if the freshwater hydraulic head calculated from the DST using eqs. 1 and 2 was more than 10 m different from a nearby head value which predates the production. On the basis of these criteria, three points were removed from the data set : pressures from DST's taken in the wells at 6-17-45-6 W5M, 8-18-45-6 W5M and 6-31-45-6 W5M.

Water-Potentiometric Map of the Study Area

The accepted pressure data for the lower Belly River Formation were converted into values of equivalent hydraulic head using Equations 3.1 and 3.2. and used to construct a water-potentiometric map. As discussed above, the equivalent freshwater hydraulic heads can be considered to be accurate to approximately 10 meters. This accuracy determines the contour interval for the water-potentiometric map of the lower Belly River sands. Figure 3.14 shows the hydraulic head data contoured using a contour interval of 10 meters of hydraulic head.

The hydraulic heads are decreasing to the west with a gradient of 0.002 to 0.004. In the regional hydraulic gradient for the lower Belly River Formation, four areas of anomalously low hydraulic head are seen. Comparison of this map with the sand isopach map shows that the areas of low hydraulic head, labelled A, B, C and D (Figure 3.15a) coincide with the thickest lenses of sand, shown cross-hatched (Figure 3.15b). Since the sand isovolume map is interpreted to be equivalent to a

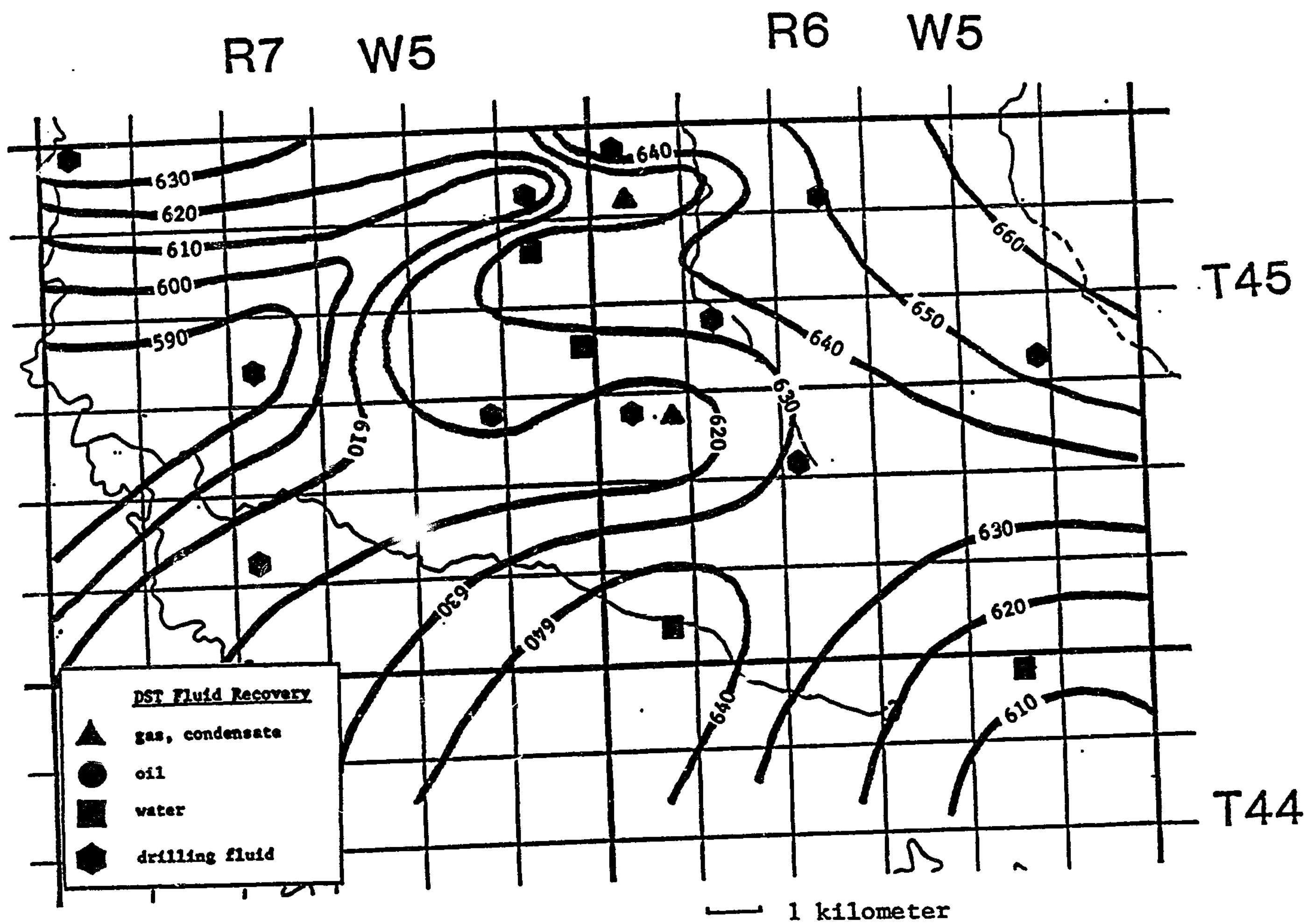


Figure 3.14: Water-potentiometric surface map, Lower Belly River Formation. Contour interval = 10m fresh-water hydraulic head.

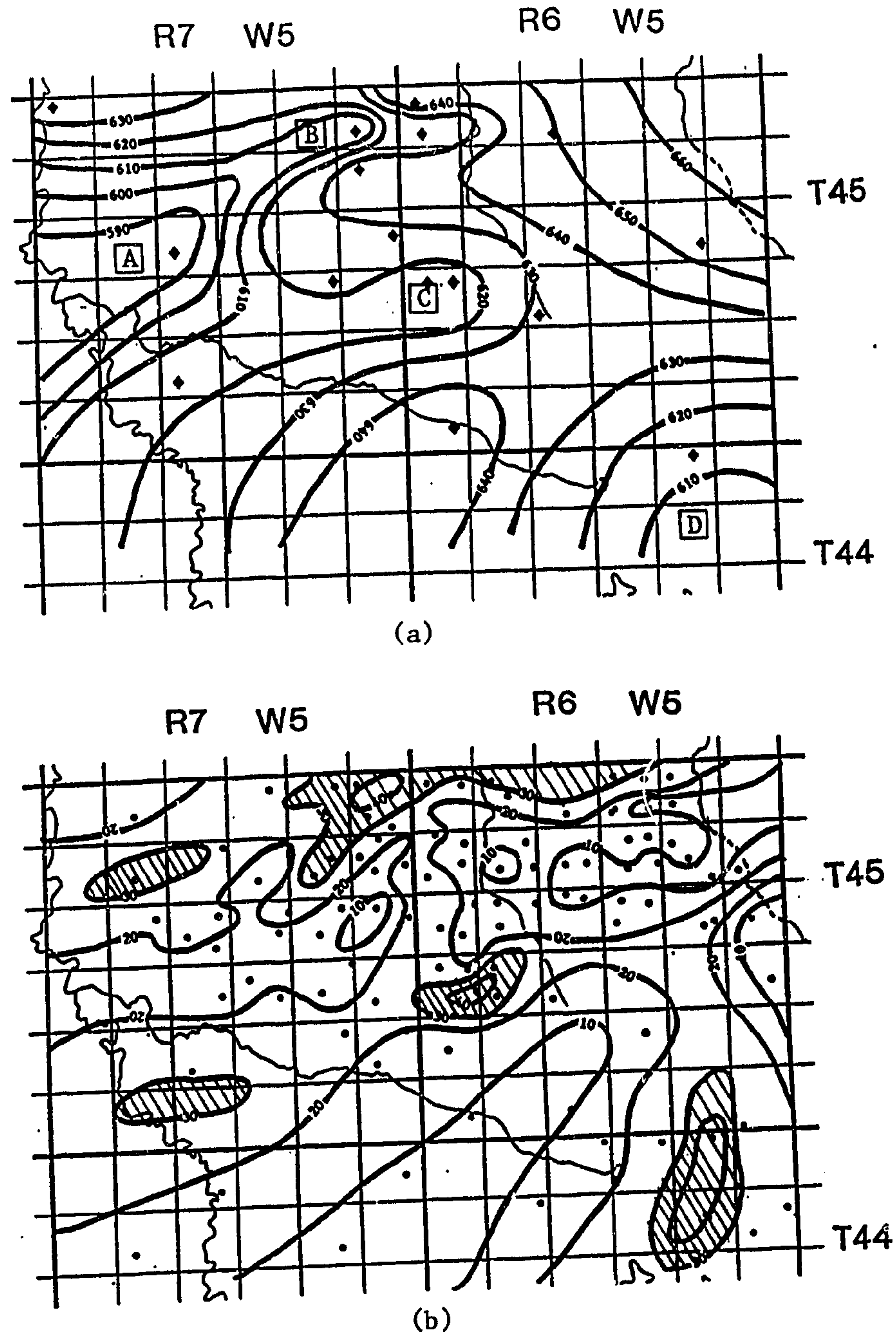


Figure 3.15: Comparison of water-potentiometric map (a) and sand isopach map (b). Note coincidence of water-potentiometric depressions A, B, C and D and thickest sands (shown cross-hatched).

transmissivity map (see page 64), the anomalous depressions are believed to be the manifestations of the hydraulic effects of the presence of high transmissivity lenses emplaced in the regional groundwater flow-field. The low hydraulic-head anomalies cause flow to converge into the lenses. No corresponding regions of anomalously high hydraulic heads are observed to be paired with the regions of anomalously low hydraulic heads as predicted from Figure 3.1.

Groundwater Flow-System Geometry in the Lower Belly River Sands

The observations that we can make from the p(z) diagram (Figure 3.12) and the water-potentiometric map (Figure 3.14) are that the groundwater is not static but is in motion and the motion has a westward component and an upward component . It was shown in the previous part of this thesis that this flow is controlled by a regional horizontal pore-pressure sink above the Belly River Formation, in the Edmonton Formation. In addition, areas of convergent lateral flow are observed which are coincident with thick sand lenses but no areas of divergent lateral flow appear to correspond to the areas of convergent flow.

The areas of convergent lateral flow seen on the water-potentiometric map can be explained as the manifestation of distortions in the regional fluid -potential field for water which are induced by the presence of thick, highly permeable lenses. The convergent flow is generated by the region of anomalously low hydraulic heads generated around the upstream (or up-gradient) sides of the lenses. The transmissivity contrast needed to generate these distortions is generated by both the thickness of sand lenses (due to the vertically stacked channel deposits, Figure 3.16) and the highly permeable conglomerates associated with the lenses.

The areas of anomalously high hydraulic heads indicative of divergent lateral flow on the downstream side of the lense predicted by the models of Tóth and Rakhit (see Figure 3.1) are not evident on the water-potentiometric map. The reason for this lack of such corresponding areas is not clear. The most likely explanation is that the downstream parts of the lens-associated potentiometric-field distortions are not observed because the relative orientations of the map plane, the sand beds and

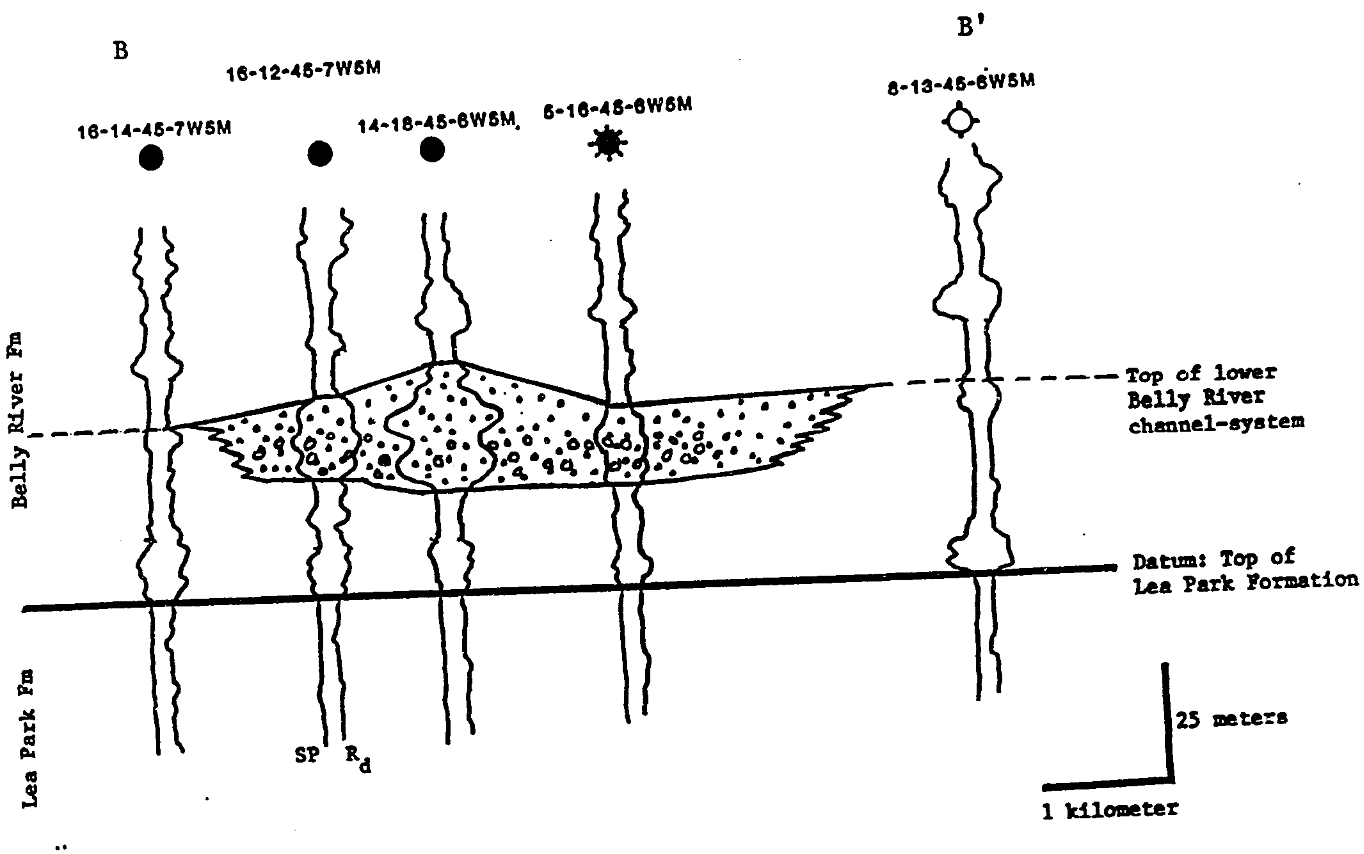


Figure 3.16: Stratigraphic cross-section B-B'showing thick sand lens in lower Belly River Formation. (See Figure 3.8 for location)

the flow field has reduced their expression in the plane of the map to the point where they cannot be detected by the given data distribution. As the regional flow in the study area is upward and westward but the dip of the beds and the map plane (coplanar with the sand beds) is downwards to the southwest, it is possible that the downstream ends of the anomalies (the regions of anomalously high fluid-potential energy) has been shifted upwards above the plane of the map (Figure 3.17). Thus its expression has been reduced in plane of the map and remains undetected.

3.3.4 Analysis of Petroleum Motion and Distribution in the Lower Belly River Formation

UVZ Analysis

An analysis of hypothetical oil migration pathways in the lower Belly River sands was carried out using the UVZ method (Hubbert, 1953). It is a graphical technique of adding the vectors of the buoyant forces and groundwater impelling forces that would act on a hypothetical particle of oil if it were placed within a carrier bed.

The UVZ method is applied in practice by overlaying the structure map of the top of the carrier bed on top of the water-potentiometric map. At the intersections of each water-hydraulic head and carrier-bed structure contour, a value of oil-hydraulic head is calculated by:

$$\frac{\rho_o}{\rho_w-\rho_o}h_o = \frac{\rho_w}{\rho_w-\rho_o}h_w - z \qquad (3.7)$$

where h_o =hydraulic head for oil, h_w=hydraulic head for water, z=elevation of the top of the carrier bed, ρ_o is oil density and ρ_w is water density. Flow paths of the oil are then inferred as being the set of trajectories orthogonal to the contours of

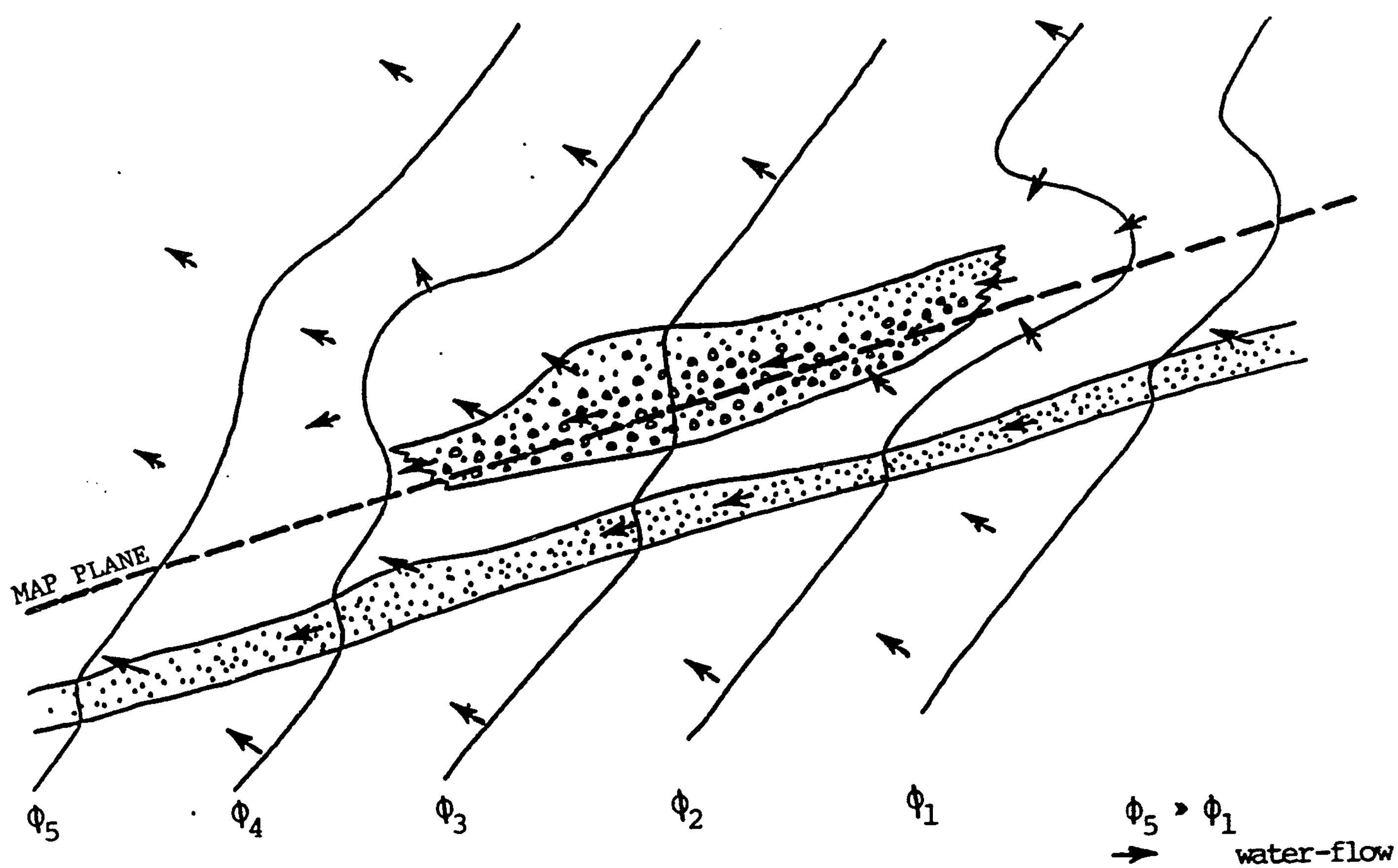


Figure 3.17: Schematic illustration of how downstream water-potential field distortion could be displaced above the plane of the water-potentiometric map by the interactions of the relative spatial orientations of bedding, flow direction and the map plane.

hydraulic head for oil. UVZ maps are limited in that they do not fully account for capillary gradients (Davis, 1987) or for changes the water and oil flow-fields caused by variations in relative permeability which are the product of rising oil saturations in the rock pores (Rostron and Tóth, 1989).

The UVZ-derived map of oil-hydraulic heads in the lower Belly River Formation is illustrated in Figure 3.18. Calculated oil-hydraulic heads assume an oil specific density of 0.85 as was reported measured from a drillstem test fluid recovery in the lower Belly River sands in a well at 8-18-45-6W5M (Energy Resources Conservation Board, 1988b).The water-potentiomteric map used is that in Figure 3.14. The carrier-bed system for this study is assumed to be a thick lower Belly River Formation channel system which runs throughout the study area (see Figure 3.16) and which could be correlated with some confidence between wells to obtain a structure map (Figure 3.19).

The oil-potentiometric map shows hydraulic heads for oil decrease from east to west. This means that if an oil phase were to be introduced into the groundwater flow field observed in the lower Belly River Formation today, it would be carried downdip and westward with the groundwater flow. Two closed oil-hydraulic head depressions exist which are coincident with the water-hydraulic depressions (labelled A and B in Figure 3.15a) and thick sand lenses. It can be inferred that any oil introduced into this system would migrate into these lenses and be trapped within them.

Hydrocarbon Distribution in the Lower Sands

The sand lenses coincident with the oil-hydraulic head depressions are known oil and gas producers. Producing wells within both lenses have been designated as producing from the same pool. This pool is designated (Energy Resources Conservation Board, 1989) as the Pembina Belly River A2A pool (Figure 3.20). Gas was discovered in the pool in 1978 and oil discovered in 1982. The Pembina Belly River A2A pool contained an estimated initial reserves of 332×10^3 m^3 with an average density of 849 kg/m^3; initial reserves of gas were estimated at 22×10^6 m^3

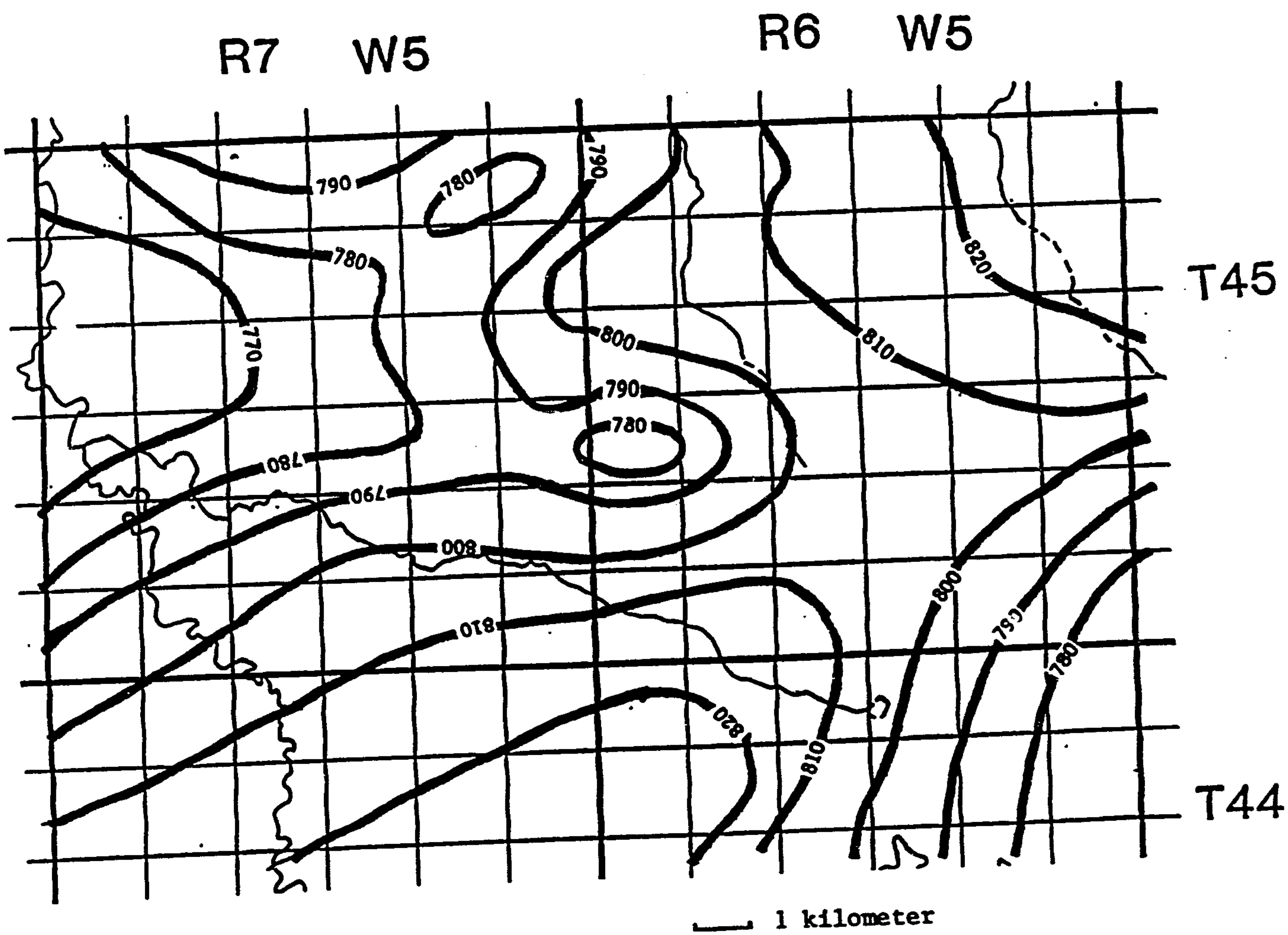


Figure 3.18: UVZ-generated oil-hydraulic head map for an oil phase of S.G = 0.84.
Contour interval = 10m oil hydraulic head.

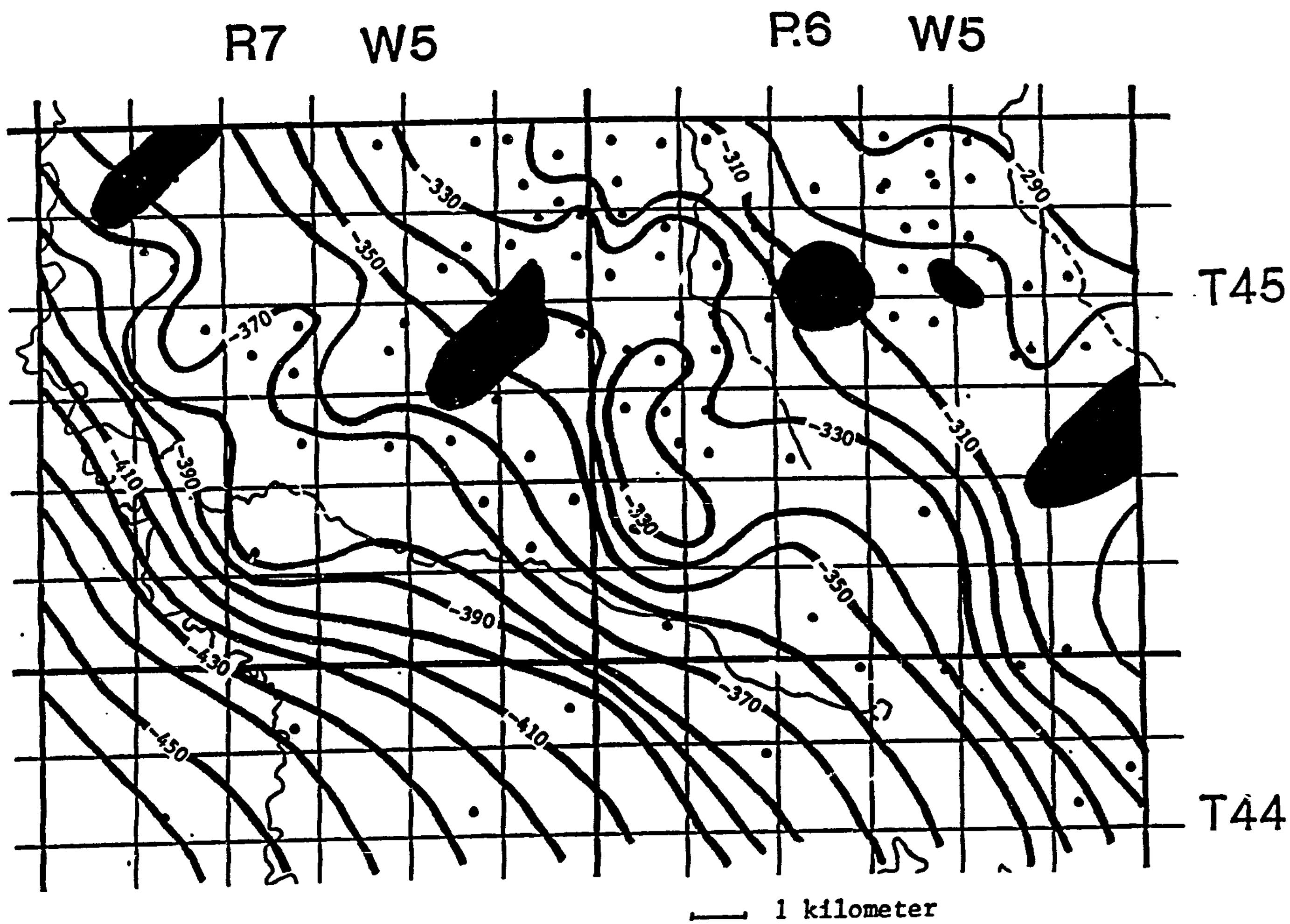


Figure 3.19: Structure on top of lower Belly River Formation fluvial channel system deposit assumed to be the carrier bed for UVZ analysis. Contour interval = 10m. Dark areas indicate regions of zero sand.

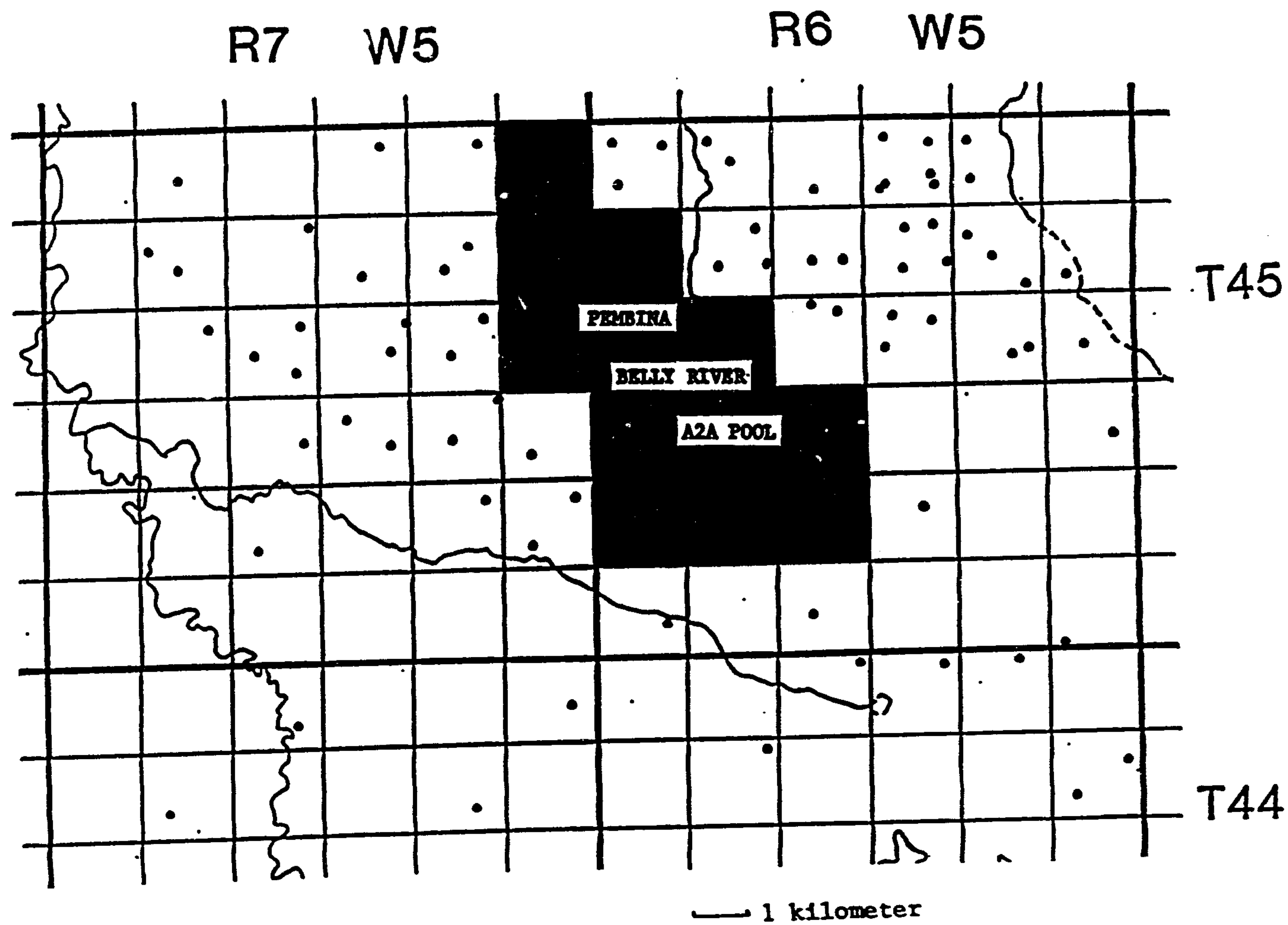


Figure 3.20: Area of Pembina Belly River A2A oil and gas Pool.

solution gas and 975×10^6 m^3 associated gas; average porosity in the reservoir is 0.14 (Energy Resources Conservation Board, 1987).

Figure 3.21 shows the gross thickness of sands where the water saturation, S_w, is less than 0.50, in the Pembina Belly River A2A Pool, assuming $R_W = 0.24$ Ω-m. As no gas or oil-water contact could be recognized (see Figure 3.11), it is postulated that groundwater motion and capillary forces generated by depostional heterogeneities are preventing vertical segregation of the gas, oil and water into distinct layers in the reservoir.

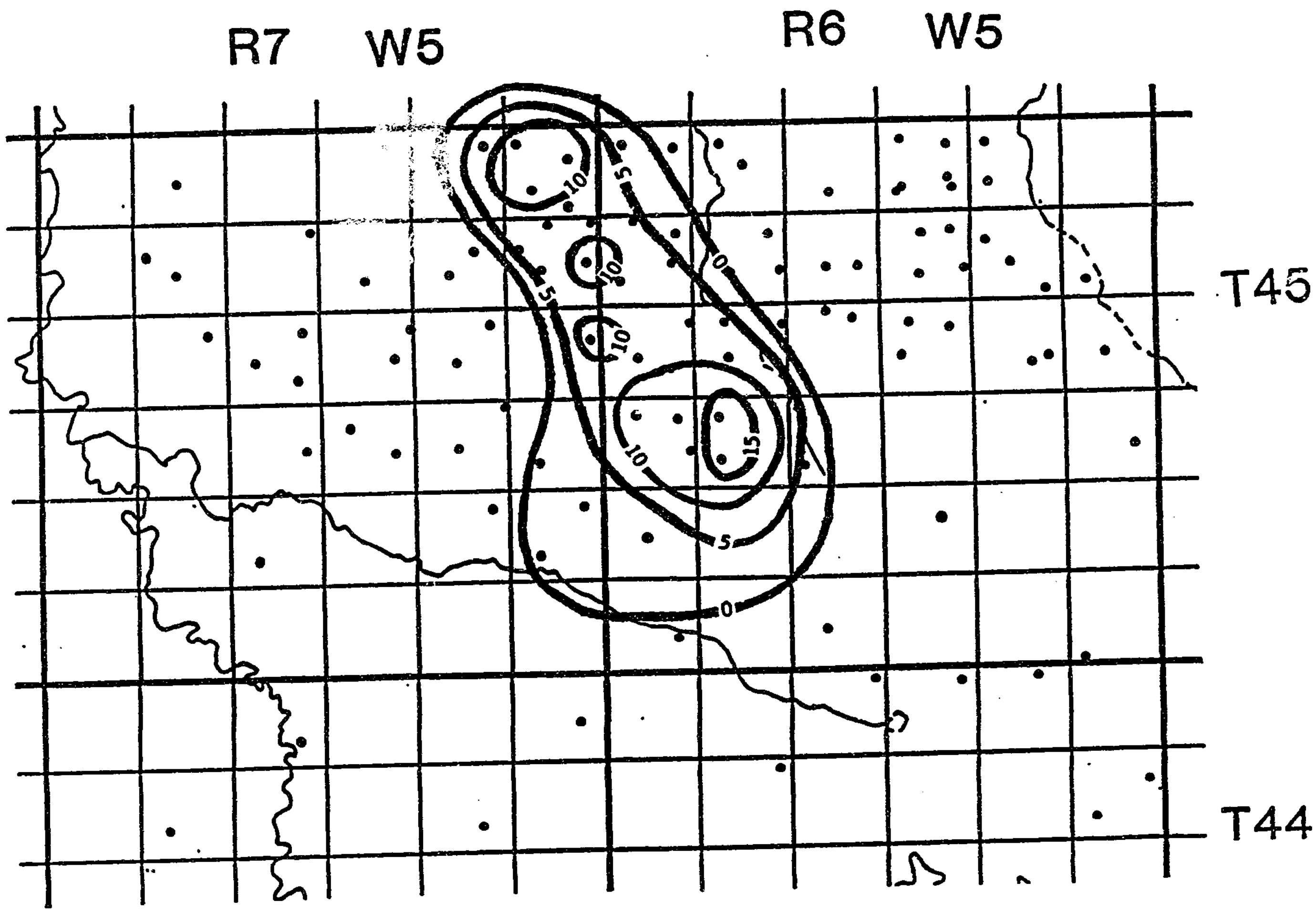


Figure 3.21: Gross hydrocarbon pay, Pembina Belly River A2A Pool, assuming $R_w = 0.24$. Contour interval = 5m of sand where S_w is less than 0.50.

3.4 Discussion

3.4.1 Petroleum Motion and Entrapment in the Lower Belly River Sands

Interpreting the map of oil-hydraulic head (Figure 3.18), one would say that an oil phase introduced into the lower Belly River sands would move downdip from east to west. This mean that the groundwater impelling forces are greater than the buoyancy forces since bouyancy-dominated migration would move the oil updip and to the east. The oil will be carried into the thickest sands because the sands are highly permeable rock lenses which distort the fluid-potential field in such a way as to focus flow into themselves. Once inside, there may be enough structural closure for buoyant forces to become dominant and trap some of the oil beneath the structural closure of the top of the sand lenses.

This interpretation does not, however, consider the effect of capillary barriers and gradients. The geologic analysis of the sands showed that they are fluvial in origin. Facies models put forth by sedimentologists (e.g., Blatt et al., 1980, p.640) would predict that the sands of the lower Belly River interval will possess a very complex internal geometry, characterized by rapid lateral and vertical variations in grain-size and lithology. Channel migration, flood events, etc., would result in juxtaposition of different lithologies with different permeabilities. On the pore scale, these rock heterogeneities will generate capillary gradients. The capillary forces will not affect the water motion, since the Belly River Formation is water-wet, but they will affect oil motion and entrapment. The water will be free to move across the boundaries of these heterogeneities but an oil phase will tend to be driven by the capillary forces into rock of increasing pore size. The capillary gradients therefore also contribute to the entrapment of the oil in the sands vertically beneath the overlying shales and laterally from finer-grained sediments.

According to the present study, the sand lenses of the Pembina Belly River A2A oil and gas pool appear to function as traps not only because of the capillary force gradients that surround them but also because they alter the flow patterns of water and oil so as to be the focal point of migrating fluids.

3.4.2 Regional Migration of Petroleum in the Belly River Formation

The map of oil-hydraulic heads (Figure 3.18) shows the heads to be decreasing from east to west (except in the southeast corner, where edge-effects may be affecting the contour pattern). If the Belly River Formation oils have indeed migrated up faults in the disturbed belt west of the study area and then laterally updip and eastward through the interconnected Belly River sands, then what is the nature of the westward decreasing oil-hydraulic heads? The apparent contradiction between an eastward migration path of Belly River oil and the observed westward-decreasing oil-hydraulic heads can be resolved if the presently observed groundwater flow-field is not the one that existed during the time of oil migration.

The major pulse of oil migration in the Alberta Basin is believed to have been during the early to mid-Tertiary (Deroo et al., 1977). This event coincided with the maximum uplift of the Laramide Orogeny and the maximum depth of burial of source rocks in the basin (Hacquebard, 1977). During this period, a basin-wide gravity-flow system evolved which flowed from the mountains eastward to the basin's easternmost edge, as postulated by Hitchon (1984) and Garven (1989). The flow system penetrated deep within the basin, at least deep enough for meteoric waters to be involved in the diagenesis of Belly River Formation sediments while at their maximum depth of burial (Longstaffe, 1986). This groundwater flow-system carried oil and gas from the west, where it was migrating up the fault systems, to the east (Figure 3.22). Along the way, the groundwater flow was focussed into highly permeable rock lenses, such as those seen in the study area. There, capillary gradients generated across lithologic boundaries helped to filter and retain some of the transported petroleum.

During the mid-Tertiary, the Alberta Basin entered a period dominated by rapid erosion. It has been estimated that since this time at least 2250 meters of sediments

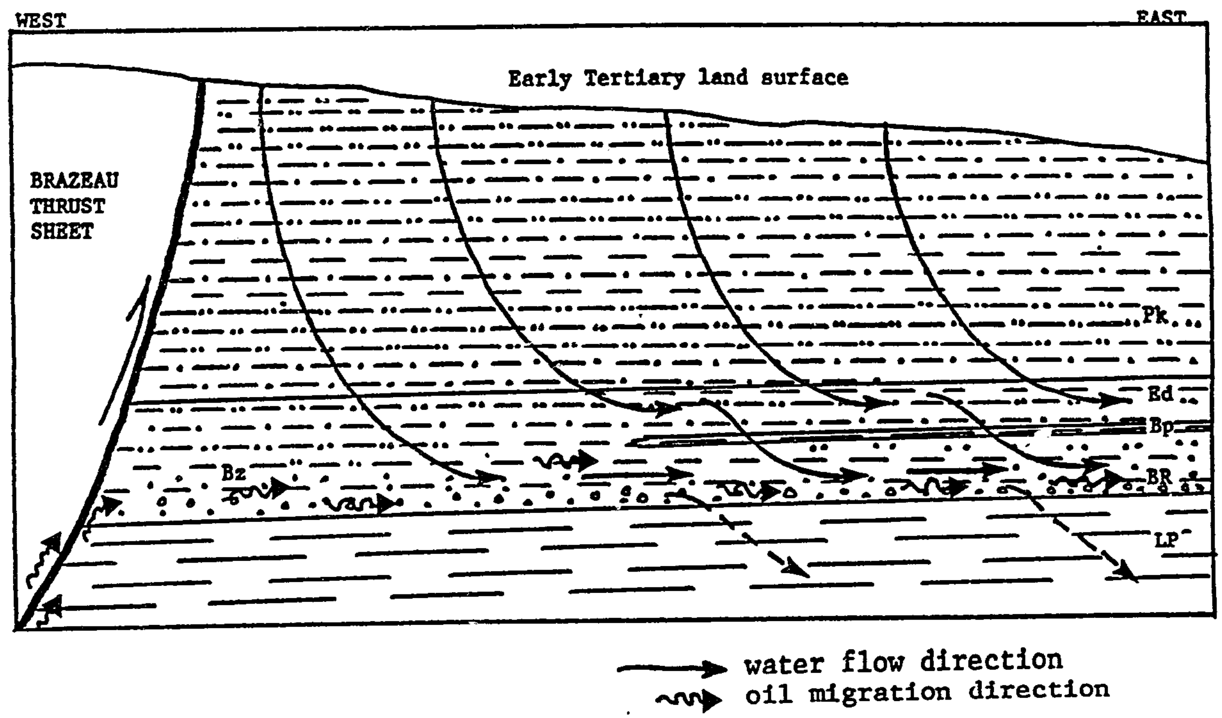


Figure 3.22: Schematic illustration of postulated oil migration pathways in the Belly River Formation of west-central Alberta during the Early Tertiary.

have been removed from the central part of the basin where the study area is located (Hitchon, 1984), with more being removed farther west (Hacquebard, 1977). Because of this reduction in overburden stress, those rocks which are elastic in nature rebounded (Locker, 1973). This caused their pores to dilate. In fine-grained elastic rock of low permeability, the pore-pressures decreased dramatically and created a regional pore-pressure sink that is controlling regional groundwater-flow in the Belly River Formation today.

As the amount of eroded thickness increases towards the mountains, it may be that the magnitude of the pore-pressure sink also increases. The sink has been strong enough to reverse the groundwater flow (Figure 3.23, see also Figure 3.14). Since the oil-hydraulic heads are derived from the water-hydraulic heads and they decrease from east to west (Figure 3.18), it is reasonable to conclude that the modern water flow-system is strong enough to prevent buoyancy-driven, non-aqueous phase oil from moving updip to the east at the present time.

One important implication of the reversal of flow direction is that the oil and gas distribution are probably not in equilibrium with the present regional groundwater-flow. Hydrocarbons may eventually be redistributed by this flow, depending on the strength of the flow versus the capillary forces trapping deposits in traps. This migration can be termed tertiary migration (Tóth, pers. comm, 1988) and may be an important process in the future evolution of the distribution of hydrocarbons in the basin.

The reversal of flow directions does not mean that water-hydraulic head maps cannot be used for exploration for highly permeable lenses. On the contrary, the effects of permeable lenses on groundwater flow fields are independent of the nature of the flow field: all that is required is a permeability contrast and a hydraulic gradient. The rock bodies that focussed the eastward flow of oil and water during the early Tertiary by their effects on the fluid-potential fields will still distort the westward flow of water observed today. For example, mapping of the flow fields in the lower Belly River Formation shows that the trapping mechanism of the Pembina Belly River A2A pool is still functioning.

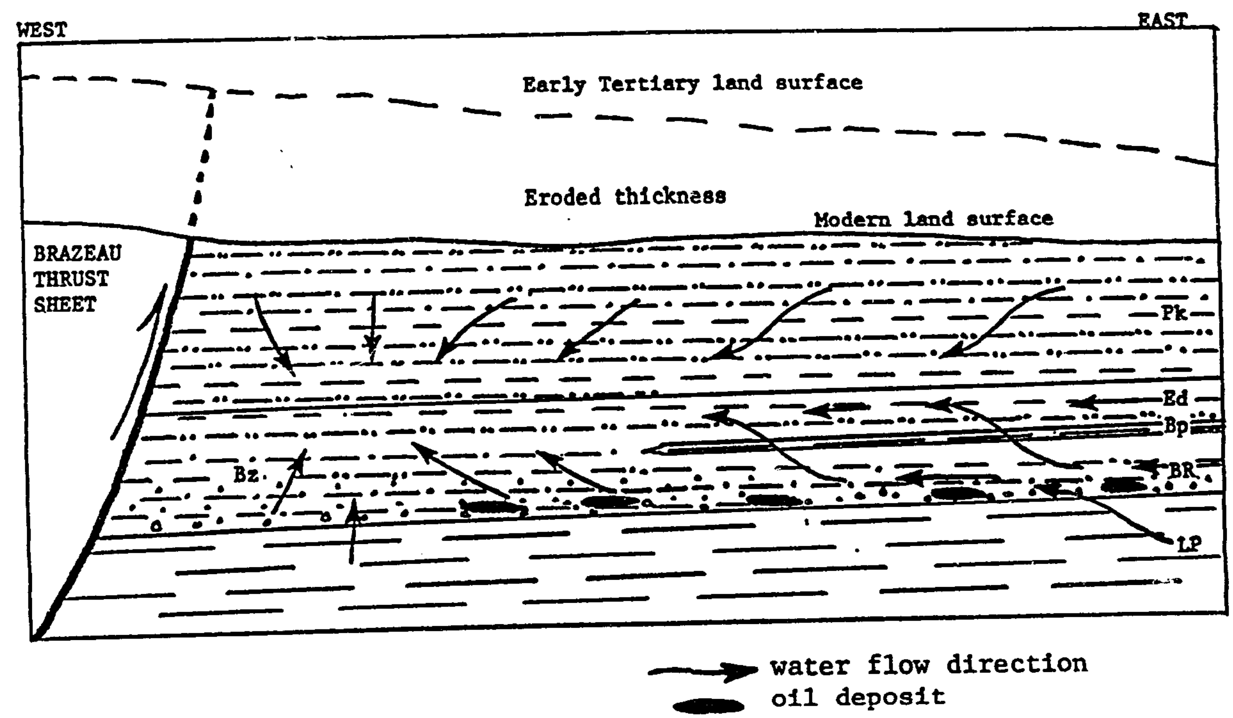


Figure 3.23: Schematic illustration illustrating the relationship between hydrocarbon distribution and modern groundwater flow field in west-central Alberta.

3.5 Summary and Conclusions

Fluids move through rock in response to fluid-potential gradients: they move from positions of high to low potential. Local variations in these gradients are controlled by heterogeneities in the rock framework. Highly permeable rock-lenses distort the fluid-potential field in such a way as to generate anomalously low fluid-potentials around their upstream ends and correspondingly high fluid-potentials around their downstream ends, relative to values expected given the regional potentiometric gradient. These anomalies cause fluids to flow preferentially through the lenses. Mapping these distortions is possible but complicated by factors such as the relative orientations of the lenses, the flow field and map planes in space and the data distribution.

Rock lenses act as petroleum traps that function on two scales. On the regional scale they distort the fluid-potential fields in such a way as to draw moving fluids preferentially into themselves. Once inside the lenses, the oil is trapped by capillary forces which act on the pore scale. The fact that the rock lenses distort fluid-flow fields on a regional scale means that they are amenable to study by hydrogeologic methods.

The field study concentrated on the Belly River Formation in an area of west-central Alberta. The Belly River Formation is known for the difficulty it presents geologists exploring for its considerable petroleum reserves by applying conventional geological techniques. The study area was chosen for its high density of DST data.

The lower Belly River Formation was mapped in terms of sand thickness. The sands are assumed to behave like a confined aquifer and therefore the sand isopach map can be used as a transmissivity map. The lower sands of the Belly River Formation create a complex pattern of ribbon sands generally trending west to east. Superimposed on the ribbon pattern is a lenticular pattern. The lenses are created by the stacking of braided-river channel deposits. The deposits in one lens where core is available show that there are highly permeable conglomerates associated with that lens, and by analogy, all the lenses in the area.

The groundwater flow in the lower sands was analyzed. Formation pressures used in this analysis were derived from drillstem tests. Analysis of the pressures through the use of a pressure-elevation diagram and a production time-line allowed for the screening-out of pressures which may have been affected by fluid production in the lower Belly River Formation.

The pressure data were used to construct a water-potentiometric map for the Lower Belly River Formation sands. It shows westward decreasing hydraulic heads which define a regional hydraulic gradient. In this gradient there are anomalous depressions which are coincident with sand lenses. The depressions are interpreted to be the upstream manifestations of the paired fluid-potential field distortions expected when highly permeable rock lenses are emplaced in a fluid-flow field. The lack of corresponding downstream anomalies is attributed to the vertical offsetting of the downstream anomalies to positions above the plane of the water-potentiometric map by the upward component of groundwater flow.

From the water-potentiometric map and the structure map of the top of the lower Belly River channel sands, an oil-potentiometric map was derived using the UVZ technique. This showed that a hypothetical light oil phase introduced into the system would migrate from east to west, i.e., downdip. It would become entrapped in oil-potentiometric closures coincident with the water-potentiometric map depressions and the sand lenses. Mapping the distribution of petroleum in the sands shows that petroleum is found in the sand lenses. When one considers the capillary forces that must be involved, it is plain to see that these sands are acting as petroleum traps, collecting migrating petroleum through distortions in the fluid-potential energy fields on the regional scale and keeping petroleum trapped within by capillary forces.

The hydraulic heads of both water and oil in the Belly River Formation of the study area decrease to the west. Therefore, water and any free oil will move from east to west. As it is believed that oil and gas migrated from sources in the westernmost part of the Alberta Basin in the early Tertiary with the aid of a basin-wide groundwater flow-system, there is a contradiction between the observed flow system and the one thought to have been in existence to move the oil and gas in the Alberta Basin. This has two important implications.

One is that the regional groundwater flow has reversed in direction since the migration of petroleum in the basin, at least as far as the Belly River Formation is concerned. It is speculated that post-Eocene erosion-induced elastic rebound and pore dilation in the overlying sediments is responsible for this. A pore-pressure sink created in these sediments is drawing the water in the Belly River Formation to the west and upwards, causing the decrease in hydraulic heads to the west. The second implication is that the traps which created the Pembina Belly River A2A Pool are still functioning, since the depressions in the potentiometric surface are still observed.

There are two consequences of these conclusions. The first is that the petroleum distribution in the Belly River Formation in the study area may be out of equilibrium with the regional hydraulic regime and there may be erosion of current petroleum deposits and tertiary migration occurring in this part of the basin. The second consequence, perhaps the most imporant for explorationists, is that since the traps are still functioning, they are detectable by mapping the groundwater flow-field. Therefore this part of the hydrogeological approach to petroleum exploration remains valid and has been shown to be applicable to the sands of the Belly River Formation in west-central Alberta.

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4. General Summary and Conclusions

The primary objective of this thesis is to show that there are field-demonstrable relationships between regional groundwater flow patterns, highly permeable rock bodies and petroleum accumulations in the Upper Cretaceous Belly River Formation of west-central Alberta, Canada. The secondary objective is to explain the presence of subhydrostatic pore-pressures in the same formation. In order to attain the first objective, it was necessary to meet the second.

The regional groundwater flow is controlled by a regionally-extensive zone of dilated rock-pores. The rock-pores have dilated in response to elastic expansion of the rock framework following removal of thousands of meters of sediment by erosion in the western part of the Alberta Basin since the mid-Tertiary. The reduction of overburden stress and dilation of rock-pores in fine-grained rock in the Edmonton Formation is responsible for the subhydrostatic pore-pressures observed in the Belly River Formation in the study area. This conclusion is supported by observation of anomalously high porosities in shales in the Edmonton Formation. Upward cross-formational flow of groundwater into the pore-pressure sink is responsible for the superhydrostatic vertical pore-pressure gradient observed in the Belly River Formation. An increase in the amount of pore-dilation to the west is believed to be responsible for the observed westward-decreasing water-hydraulic heads.

Hydrodynamic study of the lower sands of the Belly River Formation south of Buck Lake, Alberta, reveals that there exists a field-mappable relationship between regional groundwater flow patterns and the occurrence of highly-permeable lenticular sandstone bodies. These bodies cause diagnostic perturbations in the regional groundwater potential field. In the study area, these perturbations manifest themselves as regions of hydraulic head which are anomalously low relative to the values expected given the regional hydraulic gradient. These anomalously low hydraulic heads cause water to converge into and flow through the lenses.

The sandstone lenses are petroleum traps. The oil-hydraulic heads derived using the UVZ method show that the lenses distort the oil-potential field in the same manner as they distort the groundwater-potential field. Regions of anomalously low oil-hydraulic head are coincident with the sand lenses. Any migrating oil phase introduced into the groundwater flow field will converge into the lenses and likely be trapped there by capillary gradients. The lenses are sites of petroleum accumulations.

The westward decreasing water- and oil-hydraulic heads are contrary to what is expected. The regional topography slopes down to the east so regional groundwater flow would normally be expected to be west-to-east. The oil and gas in the Alberta Basin is believed to have formed in the west and migrated updip to the east, which is contrary to the westward and downdip motion of a hypothetical oil phase introduced into the regional groundwater flow field.

These contradictions can be explained if it is recognized that the regional groundwater-flow observed today is not that which existed at the time of petroleum migration. At that time, in the Early Tertiary, the regional groundwater flow was topography-driven and from west to east. The movement of petroleum was abetted by this flow and moved eastward through the Alberta Basin. Since mid-Tertiary, the Alberta Basin has been undergoing a period of net erosion. Removal of over 2000 m of sediment has let the rock framework elastically expand, causing rock-pores to dilate and pore-pressures to decrease. The reduction of pore-pressures has caused hydraulic heads to decrease to the west, reversing the previously existing west-to-east flow of groundwater in this part of the Alberta Basin. The reversed groundwater flow-field is theoretically strong enough to cause any free oil also to migrate east-to-west.

The reversal of the flow directions of water and oil in the study area does not negate the observations that the sandstone lenses are acting as petroleum traps. On the contrary, the observation that the fluid-potential fields for water and oil are distorted by the highly permeable lenses prove that the hydraulics of petroleum traps is independent of flow direction. Once this is realized and understood, then the potential of application of hydrogeologic techniques such as potentiometric maps and pore-pressure gradient analysis can be truly appreciated.

5 Appendix

Well Location W5M	K.B. (meters)	Top Channel (meters)	Sd Isopach (meters)	Depth Lea Park (meters)	m Sw<0.50
9-25-44-6	1015.6	1327	21	1377	
16-33-44-6	992.4	1352	17	1379	
15-35-44-6	990.3	1301	48	1354	
16-36-44-6	1064.9	1504			
7-26-44-7	942.3	1356			
6-29-44-7	926	1377	14	1401	
7-36-44-7	980.4	1375	7	1400	
4-1-45-6	978.8	1287	24	1341	
6-4-45-6	1005.6	1360	10	1397	
6-7-45-6	991.5	1320	17	1383	2
10-10-45-6	1016.2	1350	17	1379	
8-13-45-6	970		9.5	1304	
5-16-45-6	984	1322	13	1356	3
6-17-45-6	981.7	1317	26	1359	16
14-17-45-6	980.8		28	1360	19
8-18-45-6	975.8				12
14-18-45-6	975	1302	23	1365	14
16-18-45-6	956.8	1294	20	1341	14
6-19-45-6		961			8
7-19-45-6	944.2	1265	17	1323	6
16-19-45-6	932.7	1269	19	1307	6
6-20-45-6	942	1275	19	1316	7
14-20-45-6	931	1261	19	1299	3
16-20-45-6	934.2	1262		1299	
14-21-45-6	934.2		3	1300	
15-21-45-6	934		9.5	1290	
6-22-45-6	925	1237	18	1279	
14-22-45-6	922.2	1230	15.5	1274	
7-23-45-6	934.5	1237			
8-23-45-6	923	1219	22	1263	
6-24-45-6	938.5	1244	8	1269	
3-25-45-6	920	1213	16	1247	
1-26-45-6	935.6	1212	9	1267	
6-26-45-6	924.4	1225	11	1256	
12-26-45-6	909.6	1206	13	1243	
16-26-45-6	918.4	1209	6.5	1237	
6-27-45-6	915.8	1248	10	10	
8-27-45-6	921.4		3	1258	
14-27-45-6	913.1	1210	18.5	1258	
16-27-45-6	919.9	1217	17	1260	
6-28-45-6	938		4.5	1297	
8-28-45-6	921		6	1275	

Table A.1: Geological Data

16-28-45-6	912.7	1200	17	1264	
6-29-45-6	923.9	1260	3	1286	
8-29-45-6	927.6	1250	13	1283	
16-29-45-6	931.8	1239	13	1291	
6-30-45-6	933.7	1265	23.5	1306	5
14-30-45-6	931.8	1248	23	1300	
16-30-45-6			13	1285	
6-31-45-6	929.6	1245	20	1288	
14-31-45-6	922	1238	20	1281	
16-31-45-6	913.1	1226	25	1272	
10-32-45-6	921.4	1220	25	1273	
14-32-45-6	915	1226	32	1268	
6-33-45-6	932	1227	29	1281	
3-34-45-6	909.1		15	1261	
8-34-45-6	908.9		5	1243	
10-34-45-6	906.8	1200	29	1242	
14-34-45-6	917	1206	35.5	1256	
12-35-45-6	899.9		17	1204	
6-9-45-7	908.6		28	1350	
6-12-45-7	944.5	1308	19	1351	2
16-12-45-7	958.1	1316	20	1357	2
6-13-45-7	961.2	1320	20.5	1370	3
6-14-45-7	958	1326	16	1370	
16-14-45-7	970	1328	12	1362	
8-15-45-7	946.3	1323	23	1351	
11-15-45-7	937.9	1295	16.5	1356	
16-20-45-7	918.8	1280	21	1339	
6-21-45-7	917.9	1290	23	1331	
7-21-45-7	921.1	1292			
16-21-45-7	930.6	1299	21	1342	
16-22-45-7	972.4	1324	23	1369	
6-23-45-7	971.6		11	1366	
16-23-45-7	982		12	1370	
9-24-45-7	957	1302	20	1340	11
14-24-45-7	967		6	1352	
6-25-45-7					8
8-25-45-7	939.1	1270	29	1312	11
14-25-45-7	968.4	1297	22	1339	6
16-25-45-7	949.2	1280	20	1318	7
6-26-45-7	985.1	1328	37	1370	
10-26-45-7	976.6	1314			
6-27-45-7	978	1340	17	1327	
16-28-45-7	965.6	1338	27	1365	
6-29-45-7	923.8	1305	33	1343	

Table A.1 (continued)

12-29-45-7	911.6	1294	30	1334	
6-32-45-7	926.8		18	1334	
15-34-45-7	943.6	1277	24	1321	
15-35-45-7	937.8	1260	34.5	1308	
2-36-45-7	971.5	1297	25	1340	11
6-36-45-7	972.7	1295	39	1343	
10-36-45-7	951.5	1264	40	1314	11
13-36-45-7	946	1274	38	1315	14

Table A.1 (continued)

6-30- 45-6 W5M		7-7- 46-7 W5M	
Depth (m)	Δt (μs/m)	Depth (m)	Δt(μs/m)
237	288	249	358
274	352	274	342
291	334	298	305
355	305	354	380
381	298	382	308
393	320	422	405
412	298	458	410
427	300	498	360
463	320	535	380
487	327	574	412
509	330	630	330
537	300	688	371
578	295	716	318
640	280	739	315
660	270	775	290
687	300	812	337
720	280	886	306
738	290	913	287
769	280	948	298
793	275	977	320
810	260	1004	320
843	295	1034	280
872	265	1048	290
904	260	1084	302
919	282	1114	280
947	265	1145	287
987	278	1178	276
1021	260	1219	330
1147	280	1285	310
1190	275	1325	275
1277	260	1350	260
1355	265	1375	256
1390	260	1400	262

Table A.2: Sonic travel-times through shales versus depth in selected wells.

4-1- 45-6 W5M			
Depth (m)	Δt (μs/m)	Depth (m)	Δt (μs/m)
256	290	1350	270
296	335	1375	265
320	315	1400	270
342	320	1425	255
357	320	1450	260
391	318	1475	275
425	310		
463	320		
494	440		
507	400		
529	340		
545	430		
551	295		
584	310		
620	280		
650	280		
675	280		
695	275		
727	310		
777	290		
810	260		
841	290		
880	290		
910	285		
975	280		
1000	270		
1054	300		
1100	260		
1136	275		
1205	255		
1235	290		
1275	265		
1315	280		

Table A.2 (continued)

14-14- 45-6 W5M			
Depth (m)	Δt (μs/m)	Depth (m)	Δt (μs/m)
233	325	750	318
260	310	773	280
275	320	777	300
286	350	795	305
297	315	809	275
320	300	820	340
325	300	839	320
338	305	843	279
355	300	862	300
367	332	880	320
380	400	900	320
386	310	950	280
401	362	976	300
425	360	1016	285
427	317	1081	280
450	360	1135	280
463	290	1176	302
476	295	1220	260
490	300	1245	275
508	450	1260	280
525	300	1280	250
529	360	1301	265
543	450	1320	280
560	300	1340	270
580	290	1360	281
582	300	1380	278
640	360	1400	264
622	280	1420	260
625	285	1440	270
662	285		
680	360		
705	300		
725	300		

Table A.2 (continued)

7-19- 45-6 W5M			
Depth (m)	Δt (μs/m)	Depth (m)	Δt (μs/m)
357	295	1250	260
402	355	1280	262
423	323	1305	255
477	410	1325	273
495	340	1350	283
510	372	1375	270
525	340	1400	250
531	368	1425	248
582	312	1450	265
625	290		
653	285		
675	290		
702	296		
724	300		
751	330		
777	285		
800	308		
825	305		
850	270		
874	320		
900	280		
926	280		
950	315		
1010	292		
1024	320		
1047	300		
1073	260		
1100	295		
1124	292		
1149	270		
1180	280		
1199	268		
1225	277		

Table A.2 (continued)

Table A.3: Water-table Elevation Data

Location	Type	Ground Level (ft)	Ground Level (m)	Depth to Water (ft)	Depth to Water (m)	Water Table Elevation (m)
5-1-44-6 W5	flowing shot hole	3233	985	25	8	978
9-7-44-6 W5	flowing shot hole					
15-7-44-6 W5	flowing shot hole	3078	938	25	8	931
7-11-44-6 W5	industrial well					
9-20-44-6 W5	flowing shot hole	3300	1006	25	8	998
16-20-44-6 W5	industrial well	3310	1009	14	4	1005
5-22-44-6 W5	flowing shot hole	3350	1021	35	11	1010
15-28-44-6 W5	flowing shot hole					
16-31-44-6 W5	flowing shot hole					
13-32-44-6 W5	flowing shot hole	3224	983	55	17	967
9-32-44-6 W5	flowing shot hole					
14-32-44-6 W5	flowing shot hole					
16-32-44-6 W5	flowing shot hole					
6-33-44-6W5	flowing shot hole					
7-33-44-6 W5	flowing shot hole					
14-33-44-6 W5	flowing shot hole					
8-34-44-6 W5	flowing shot hole					
12-34-44-6 W5	flowing shot hole	3246	989	35	11	979
13-34-44-6 W5	flowing shot hole	3246	989	30	9	980
16-34-44-6 W5	industrial well	3248	990	6	2	986
1-35-44-6 W5	flowing shot hole	3300	1006	40	12	992
6-35-44-8 W5	flowing shot hole					
8-35-44-6 W5	flowing shot hole	3248	990	45	14	976
9-35-44-6 W5	flowing shot hole					
13-35-44-6 W5	flowing shot hole					
16-35-44-6 W5	flowing shot hole					
13-36-44-6 W5	flowing shot hole					
4-1-44-7 W5	flowing shot hole					
13-10-44-7 W5	domestic well	3150	960	13	4	956
12-11-44-7 W5	flowing shot hole					

Table A.3 (continued)

6-15-44-7 W5	industrial well	3050	930	20	6	924
4-18-44-7 W5	flowing shot hole					
SE 21-44-7W5	domestic well			11	3	
5-28-44-7 W5	flowing shot hole					
6-28-44-7 W5	flowing shot hole					
6-29-44-7 W5	flowing shot hole					
8-29-44-7 W5	flowing shot hole					
6-30-44-7 W5	flowing shot hole					
8-30-44-7 W5	flowing shot hole					
6-31-44-7 W5	rig well	3040	927	60	18	908
NE 31-44-7 W5	flowing shot hole					
13-33-44-7 W5	flowing well			flowing		
12-1-45-6 W5	flowing shot hole					
16-2-45-6 W5	flowing shot hole					
1-4-45-6 W5	flowing shot hole					
1-6-45-6 W5	stock well	3230	985	24	7	977
NW 6-45-6 W5	domestic well			15	5	
3-8-45-6 W5	stock well	3340	1018	54	16	1002
7-8-45-6 W5	stock well	3325	1013	70	21	1013
9-11-45-6 W5	flowing shot hole					
1-13-45-6 W5	stock well	3200	975	55	17	959
9-13-45-6 W5	flowing shot hole					
9-13-45-6 W5	domestic well	3100	945	11	3	942
1-14-45-6 W5	flowing shot hole					
8-16-45-6 W5	flowing shot hole					
9-16-45-6 W5	flowing shot hole					
8-18-45-6 W5	flowing shot hole					
NW 18-45-6 W5	stock well			30	9	
6-19-45-6 W5	industrial well	3160	963	67	20	943
8-19-45-6 W5	flowing shot hole					
9-19-45-6 W5	flowing shot hole					
8-20-45-6 W5	stock well	3150	960	24	7	953

Table A.3 (continued)

15-20-45-6 W5	stock well	3065	934	10	3	931
16-20-45-6 W5	flowing shot hole					
14-22-45-6 W5	flowing shot hole	2995	913	35	11	902
1-23-45-6 W5	flowing shot hole					
4-23-45-6 W5	domestic well	3120	951	90	27	939
8-23-46-6 W5	domestic well			flowing		
3-25-45-6 W5	domestic well			50	15	
1-24-45-6 W5	flowing shot hole					
SW 24-45-6 W5	domestic well	3100	945	35	11	
5-24-45-6 W5	stock well	3050	930	66	20	910
8-24-45-6 W5	flowing shot hole					
10-24-45-6 W5	stock well	3030	924	43	13	910
14-24-45-6 W5	domestic well	3025	922	30	9	913
SE 25-45-6 W5	domestic well	3000	914	50	15	899
5-25-45-6 W5	domestic well	3000	914	52	16	899
13-25-45-6 W5	domestic well	3000	914	37	11	903
16-25-45-6 W5	stock well	3070	936	68	21	915
1-26-45-6 W5	domestic well	3040	927	51	16	911
NE 26-45-6 W5	stock well			35	11	
3-28-45-6 W5	stock well	3060	933	18	5	927
NW 28-45-6 W5	domestic well			100		
8-29-45-6 W5	flowing shot hole					
9-29-45-6 W5	flowing shot hole					
13-30-45-6 W5	domestic well	3075	937	64	20	918
4-31-45-6 W5	flowing shot hole					
5-31-45-6 W5	flowing shot hole					
13-31-45-6 W5	stock well	3025	922	21	6	916
NW 31-45-6 W5	domestic well			50		
8-32-45-6 W5	domestic well	3050	930	5	2	928
13-32-45-6 W5	flowing shot hole	3251	991	40	12	979
6-33-45-6 W5	industrial well	3075	937	73	22	915
SE 33-45-6 W5	domestic well			40		
NW 33-45-6 W5	domestic well			74		

Table A.3 (continued)

15-33-45-6 W5	stock well	3090	942	15	5	937
13-34-45-6 W5	stock well	3050	930	70	21	908
NW 35-45-6 W5	domestic well	2948	899	30		
14-35-45-6 W5	domestic well			flowing		
16-35-45-6 W5	flowing shot hole					
NE 35-45-6 W5	domestic well			flowing		
13-36-45-6 W5	flowing shot hole					
NE 1-45-7 W5	stock well	3140	957	35	11	946
1-2-45-7 W5	domestic well	3100	945	18	5	940
SW 2-45-7 W5	domestic well			165		
4-3-45-7 W5	domestic well	3125	953	35	11	942
SW 4-45-7 W5	domestic well	3010	917	220	67	850
1-5-45-7 W5	domestic well	2950	899	100	30	869
SW 5-45-7 W5	stock well	2950	899	12	4	896
3-5-45-7 W4	stock well	2950	899	50	15	884
13-6-45-7 W4	flowing shot hole					
SW 7-45-7 W5	stock well			108		
5-7-45-7 W5	domestic well	2990	911	45	14	898
6-7-45-7 W5	flowing shot hole					
13-7-45-7 W5	stock well	2950	899	5	2	898
8-8-45-7 W5	domestic well	2930	893	50	15	878
9-8-45-7 W5	flowing shot hole					
10-8-45-7 W5	flowing shot hole					
5-9-45-7 W5	stock well	2975	907	35	11	896
12-9-45-7 W5	stock well	2950	899	60	18	881
12-9-45-7 W5	flowing shot hole					
4-10-45-7 W5	stock well	3140	957	15	5	953
14-10-45-7 W5	stock well	3020	920	8	2	918
16-11-45-7 W5	industrial well	3100	945	65	20	925
6-12-45-7 W5	industrial well	3090	942	45	14	928
7-12-45-7 W5	flowing shot hole	3103	946	40	12	934
15-12-45-7 W5	stock well	3115	949	52	16	934

Table A.3 (continued)

8-13-45-7 W5	domestic well	3200	975	29	9	967
14-15-45-7 W5	stock well	3100	945	36	11	934
4-16-45-7 W5	stock well	2930	893	61	19	874
NW 17-45-7 W5	stock well			69		
16-17-45-7 W5	stock well	2945	898	90	27	870
9-18-45-7 W5	stock well	2870	875	34	10	864
1-19-45-7 W5	stock well	2880	878	60	18	859
SW 19-45-7 W5	stock well			17		
5-19-45-7 W5	domestic well	2950	899	5	2	898
13-19-45-7 W5	flowing shot hole					
NW 19-45-7 W5	stock well			22		
13-20-45-7 W5	domestic well	2920	890	96	29	861
16-20-45-7 W5	stock well	3010	917	170	52	866
SW 21-45-7 W5	stock well			130		
5-21-45-7 W5	domestic well	2975	907	130	40	867
13-21-45-7 W5	stock well	3000	914	170	52	862
NE 21-45-7 W5	domestic well			80		
8-22-45-7 W5	industrial well	3170	966	130	40	927
15-22-45-7 W5	domestic well	3185	971	102	31	940
SE 24-45-7 W5	domestic well			25		
1-24-45-7 W5	stock well	3250	991	30	9	981
13-25-45-7 W5	domestic well	3160	963	12	4	960
NW 25-45-7 W5	stock well			30		
NE 26-45-7 W5	domestic well			60		
NE 26-45-7 W5	stock well	3150	960	45	14	945
SE 27-45-7 W5	domestic well			21		
6-27-45-7 W5	industrial well	3190	972	92	28	944
14-27-45-7 W5	stock well	3210	978	18	5	973
NE 27-45-7 W5	domestic well			12		
16-27-45-7 W5	domestic well	3175	968	18	5	962
5-28-45-7 W5	stock well	3050	930	210	64	866
6-28-45-7 W5	domestic well	3070	936	35	11	925
9-28-45-7 W5	stock well	3150	960	143	44	917

Table A.3 (continued)

12-28-45-7	W5	stock well	3080	939	251	77	862
8-29-45-7	W5	stock well	3070	936	110	34	902
14-29-45-7	W5	domestic well	3000	914	130	40	875
16-30-45-7	W5	stock well	2950	899	120	37	862
16-31-45-7	W5	stock well	2920	890	79	24	866
8-32-45-7	W5	domestic well	3100	945	174	53	892
13-32-45-7	W5	domestic well	2930	893	15	5	888
14-32-45-7	W5	stock well	2975	907	150	46	861
16-32-45-7	W5	stock well	3060	933	156	48	885
8-33-45-7	W5	domestic well	3230	985	15	5	980
14-33-45-7	W5	domestic well	3135	956	190	58	898
NW 33-45-7	W5	domestic well			190		
NW 33-45-7	W5	domestic well			200		
2-34-45-7	W5	domestic well	3200	975	60	18	957
15-34-45-7	W5	domestic well	3070	936	45	14	922
4-35-45-7	W5	domestic well	3170	966	65	20	946
13-35-45-7	W5	domestic well	3050	930	45	14	916
13-35-45-7	W5	flowing shot hole					
1-36-45-7	W5	flowing shot hole					
5-36-45-7	W5	stock well	3095	943	143	44	900
8-36-45-7	W5	flowing shot hole					
16-36-45-7	W5	stock well	3040	927	85	26	901

Z (m)	hw (m)= 580	590	600	610	620	630	640	650	660
-460	763.53	775.29	787.06	798.82	810.59	822.35	834.12	845.88	857.65
-450	761.76	773.53	785.29	797.06	808.82	820.59	832.35	844.12	855.88
-440	760.00	771.76	783.53	795.29	807.06	818.82	830.59	842.35	854.12
-430	758.23	770.00	781.76	793.53	805.29	817.06	828.82	840.59	852.35
-420	756.47	768.23	780.00	791.76	803.53	815.29	827.06	838.82	850.59
-410	754.70	766.47	778.23	790.00	801.76	813.53	825.29	837.06	848.82
-400	752.94	764.70	776.47	788.23	800.00	811.76	823.53	835.29	847.06
-390	751.18	762.94	774.70	786.47	798.23	810.00	821.76	833.53	845.29
-380	749.41	761.18	772.94	784.70	796.47	808.23	820.00	831.76	843.53
-370	747.65	759.41	771.18	782.94	794.70	806.47	818.23	830.00	841.76
-360	745.88	757.65	769.41	781.18	792.94	804.70	816.47	828.23	840.00
-350	744.12	755.88	767.65	779.41	791.18	802.94	814.70	826.47	838.23
-340	742.35	754.12	765.88	777.65	789.41	801.18	812.94	824.70	836.47
-330	740.59	752.35	764.12	775.88	787.65	799.41	811.18	822.94	834.70
-320	738.82	750.59	762.35	774.12	785.88	797.65	809.41	821.18	832.94
-310	737.06	748.82	760.59	772.35	784.12	795.88	807.65	819.41	831.18
-300	735.29	747.06	758.82	770.59	782.35	794.12	805.88	817.65	829.41
-290	733.53	745.29	757.06	768.82	780.59	792.35	804.12	815.88	827.65

Table A.4: Table for calculating values of oil-hydraulic head given the hydraulic head for water (hw) and the structural elevation (Z).

Well Location	Dates on Production	ERCB Designated Pool
15-35-44-6 W5M	Feb. 1988	unassigned
6-7-45-6 W5M	Feb. 1986- March 1988	BR A2A
14-8-45-6 W5M	Jan.1988-March 1988	BR A2A
6-17-45-6 W5M	May 1985-Oct. 1985	BR A2A
8-18-45-6 W5M	Oct. 1983-Jan.1984	BR A2A
14-18-45-6 W5M	Dec. 1982-March 1988	BR A2A
7-19-45-6 W5M	May 1985-March 1988	BR A2A
14-20-45-6 W5M	Dec. 1984-March 1988	BR A2A
8-23-45-6 W5M	July. 1984	unassigned
3-25-45-6 W5M	Nov. 1982-Jan.1983	unassigned
6-30-45-6 W5M	Jan. 1987-March 1988	unassigned
14-31-45-6 W5M	March 1980-March 1988	BR JJ
7-34-45-6 W5M	July 1978-March 1988	BR A
6-9-45-7 W5M	Jan. 1987-March 1988	unassigned
16-11-45-7 W5M	Dec. 1986-March 1988	unassigned
6-25-45-7 W5M	July. 1983	unassigned
16-25-45-7 W5M	Feb. 1987-March 1988	BR A2A
10-36-45-7 W5M	Jan. 1987-March 1988	BR A2A

Table A.5: Lower Belly River Formation Production Data.

VITA

Kevin Preston Parks was born on August 15, 1963, at the University of Alberta Hospital in Edmonton, Alberta. This was the same day that his future graduate advisor, Dr. Tóth, had a landmark paper published which indirectly contributed to the subject matter of this thesis. Dr.Tóth was working for the Alberta Research Council which, at that time, was headquartered on the same city block as the U. of A. Hospital. Coincidence?

The young Kevin was always interested in rocks and dinosaurs and, in high school, the oil industry. This interest led him to pursue his B.Sc. in Geology at the University of Alberta which he recieved in 1985. A brief time in the oil-patch with Dome Petroleum convinced him that the life of an oil-company geologist was not for him and so he returned to the University of Alberta to tackle a research project under Dr. Tóth.

Kevin currently resides in Edmonton and plans to follow a career-path in hydrogeology. He hopes to do his best to help clean up the environment so his kids will have the chance to lead a life as good as he has.