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Subsurface Characterization of Acid-Gas Injection Operations in the Provost Area

Energy Resources Conservation Board

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Executive Summary

Injection of acid gas in the Provost area in southeastern Alberta takes place at six sites into four different stratigraphic intervals. Acid gas mixed with water is or was injected into Lower Mannville hydrocarbon reservoirs at Bellshill Lake and Hansman Lake. At Kelsey, Galahad, Thompson Lake and Provost-Keg River, dry acid gas is injected into aquifers of the Upper Devonian Wabamun and Leduc formations and into the Middle Devonian Keg River Formation, respectively. The oldest acid-gas injection site in the study area is Galahad, where injection commenced in 1994. The Hansman Lake operation was rescinded in 1996 after 15 months of sour water injection. By the end of 2004, approximately 350 kt of acid gas had been injected into deep geological formations in the Provost area.

If only the natural setting is considered, including geology and flow of formation waters, the basin- and local-scale hydrogeological analyses indicate that injecting acid gas into these deep geological units in the Provost area is basically a safe operation with no potential for acid gas migration to shallower strata, potable groundwater and the surface. At Bellshill Lake and Hansman Lake, where sour water is or was injected into currently producing Lower Mannville reservoirs, the injected water will remain within the respective pool outlines and will partly be recycled in the injection/production cycle. In the cases of dry acid-gas injection, the acid gas plume will likely be reduced by dissolution, dispersion, residual gas saturation and trapping along the migration pathway and therefore not reach the overlying aquifers. In the unlikely event of further migration, it would take in the order of 5000 years before acid gas could be detected in the overlying Lower Mannville aquifer at Galahad and Thompson Lake, where acid gas is injected into the Leduc Formation. Once in the Lower Mannville aquifer, the acid gas theoretically would have to move farther updip along the top of the aquifer for another 150 km (~ 15,000 years), before it would reach the ground surface in the outcrop area of the Lower Mannville aquifer. Although migration of acid-gas from the Wabamun into the Lower Mannville aquifer at Kelsey is very likely, the acid gas would have to complete an even longer migration path before it reaches the area of Lower Mannville Group outcrop. Ultimately, it is not realistic that this long migration path will ever be completed because of dissolution, dispersion, residual gas saturation and trapping of the acid gas along the migration path. At Provost-Keg River, vertical migration will be prevented by the effective aquitard characteristics of the Prairie Formation. In addition, low-permeability sediments of the Beaverhill Lake Group, the Ireton Formation and the Colorado Group provide additional vertical barriers to flow to shallow aquifers.

The entire stratigraphic interval from the Keg River Formation to the Lower Mannville Group is overlain by at least one thick shale sequence, the Colorado Group. There are many barriers to acid gas migration from an injection zone into other strata, and the flow process, if it will ever happen, would take an extremely long time, on a geological time scale. Any acid gas plume would disperse and dissolve in formation water during flow on such large time and spatial scales.

Based on available data, it is unlikely that there is potential for acid gas leakage through fractures. However, the possibility for upward leakage of acid gas exists along wells that were improperly completed and/or abandoned, or along wells whose cement and/or tubing has degraded or may degrade in the future as a result of chemical reactions with formation brine and/or acid gas. The Provost area has a very high well density with the majority of the wells penetrating hydrocarbon-bearing strata in the Lower Mannville Group. Wells in the Provost area were drilled, and successively abandoned, as early as the late 1940s and, considering the old age, damage to or improper well completion is a likely. No leakage has been detected and reported to date, however,

the potential for this occurring in the future should be considered by both operators and regulatory agencies.

These conclusions are based on a qualitative hydrogeological analysis in the sense that the geological and hydrogeological data were interpreted within the framework of the most current knowledge about the Alberta Basin and its contained fluids. No quantitative analysis based on numerical modeling was performed because, to the best knowledge of the authors, no such models are available. Predictive numerical models of acid gas injection and flow, if not already in existence, should be developed and used to validate the qualitative hydrogeological analysis presented in this report. The effects of fluid-rock interactions and of the natural stress regime as well as stress induced by injection processes on reservoir rock and caprock should be assessed to confirm integrity. The potential for and risk of leakage through existing wells should be better assessed by sampling and analyzing cements and completions of abandoned wells. In addition, a monitoring program including fluid sampling in wells in the vicinity of existing injection wells would support and provide feedback to the analysis and modelling, and greatly enhance the confidence in the safety of the operations.

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1 Introduction

Over the past decade, oil and gas producers in western Canada (Alberta and British Columbia) have been faced with a growing challenge to reduce atmospheric emissions of hydrogen sulphide (H_2S), which is produced from "sour" hydrocarbon pools. Sour oil and gas are hydrocarbons that contain H_2S and carbon dioxide (CO_2), which have to be removed before the produced oil or gas is sent to markets. Since surface desulphurization through the Claus process is uneconomic, and the surface storage of the produced sulphur constitutes a liability, increasingly more operators are turning to acid gas disposal by injection into deep geological formations. Acid gas is a mixture of H_2S and CO_2, with minor traces of hydrocarbons, that is the by-product of "sweetening" sour hydrocarbons. In addition to providing a cost-effective alternative to sulphur recovery, the deep injection of acid gas reduces emissions of noxious substances into the atmosphere and alleviates the public concern resulting from sour gas production and flaring.

The first acid-gas injection operation was approved in 1989 and started in 1990 in Alberta. To date, 51 injection operations have been approved in Alberta and British Columbia; their locations are shown in Figure 1. In Alberta, the Oil and Gas Conservation Act requires that operators apply for and obtain approval from the Alberta Energy and Utilities Board (EUB), the provincial regulatory agency, to dispose of acid gas. Before approving any operation, the EUB reviews the application to maximize conservation of hydrocarbon resources, minimize environmental impact and ensure public safety. To adequately address these matters, the EUB requires that the applicants submit information regarding surface facilities, injection well configurations, geological characteristics of the injection reservoir or aquifer, and operations. After approval for acid gas injection is granted, the operators have to submit to the regulatory agencies biannual progress reports on the operations.

Although the purpose of the acid-gas injection operations is to dispose of H_2S, significant quantities of CO_2 are being injected at the same time because it is costly to separate the two gases. To date, more CO_2 than H_2S has been injected into deep geological formations in western Canada. In the context of current efforts to reduce anthropogenic emissions of CO_2, these acid-gas injection operations represent an analogue to geological storage of CO_2. The latter is an immediately-available and technologically-feasible way of reducing CO_2 emissions into the atmosphere that is particularly suited for land-locked regions located on sedimentary basins, such as the Alberta Basin in western Canada. Large-scale injection of CO_2 into depleted oil and gas reservoirs and into deep saline aquifers is one of the most promising methods of geological storage of CO_2, and in this respect, it is no different from acid-gas injection operations. However, before implementation of greenhouse gas geological storage, a series of questions needs addressing, the most important ones relate to the short- and long-term fate of the injected CO_2. Thus, the study of the acid-gas injection operations in western Canada provides the opportunity to learn about the safety of these operations and about the fate of the injected gases, and represents a unique opportunity to investigate the feasibility of CO_2 geological storage.

Geographically, most of the acid-gas injection operations in western Canada can be grouped in several clusters (Figure 1). The six operations that are the subject of this report (Kelsey-Wabamun, Galahad-Leduc, Bellshill Lake-Blairmore, Provost-Leduc, Provost-Keg River, and Hansman Lake-Cummings) form the cluster in the Provost area and inject acid gas into Devonian to Lower Cretaceous strata. An acid-gas injection operation usually is associated with a single gas plant that is the source of the acid gas stream. However, if the acid gas from one plant is injected into different stratigraphic units, or has different compositions (i.e., dry gas, acid gas mixed with

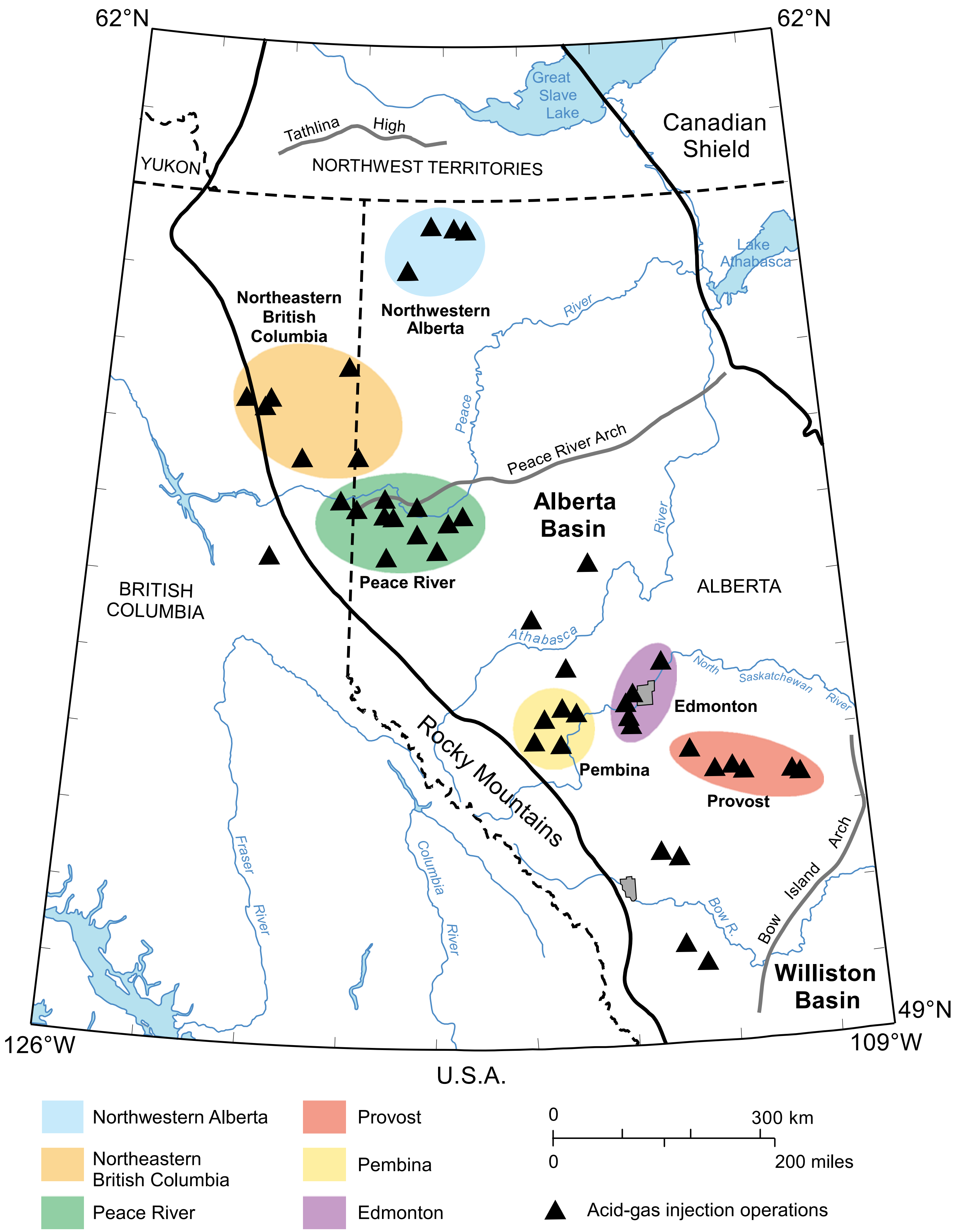


Figure 1. Location of acid-gas injection operation clusters and isolated acid-gas injection operations in western Canada at the end of 2004.

water), separate applications have to be submitted for each case. Hence, an acid gas operation may have more than one injection site.

Previous work characterized the subsurface at the injection sites in the Pembina area of west-central Alberta, the Edmonton area of central Alberta, and in northeastern British Columbia (Bachu *et al*., 2003a, b, 2004a, Buschkuehle and Michael, 2005). Future reports are planned for the Peace River and northwestern Alberta areas (Figure 1). The subsurface characterization of the acid-gas injection operations in the Provost area will help to address various issues that relate to the disposal and/or sequestration of acid and greenhouse gases, specifically into Devonian to Lower Cretaceous strata in southeastern Alberta. The characterization is based on reservoir-scale data and information submitted by the operators to the EUB, on basin-scale work performed at the Alberta Geological Survey (AGS) during the last 15 years, and on local and reservoir-scale work performed by the AGS specifically for this report.

2 Selection of an Acid-Gas Injection Site

In Alberta, applications for acid gas disposal must conform to the specific requirements listed in Chapter 4.2 of Guide 65 that deals with applications for conventional oil and gas reservoirs (EUB, 2000). The selection of an acid-gas injection site needs to address various considerations that relate to: proximity to sour oil and gas production that is the source of acid gas; confinement of the injected gas; effect of acid gas on the rock matrix; protection of energy, mineral and groundwater resources; equity interests; wellbore integrity and public safety (Keushnig, 1995; Longworth *et al*., 1996). The surface operations and the subsurface aspects of acid gas injection depend on the properties of the H_2S and CO_2 mixture, which include, but are not limited to non-aqueous phase behaviour, water content, hydrate formation and the density and viscosity of the acid gas (Carroll and Lui, 1997; Ng *et al*., 1999).

2.1 Acid Gas Properties

The acid gas obtained after the removal of H_2S and CO_2 from the sour gas may also contain 1%-3% hydrocarbon gases, and is saturated with water vapour in the range of 2-6%. In their pure state, CO_2 and H_2S have similar phase equilibria, but at different pressures and temperatures (Carroll, 1998a). They exhibit the normal vapour/liquid behaviour with pressure and temperature (Figure 2), with CO_2 condensing at lower temperatures than H_2S. Methane (CH_4) also exhibits this behaviour, but at much lower temperatures. The phase behaviour of the acid-gas binary system is represented by a continuous series of two-phase envelopes (separating the liquid and gas phases) located between the unary bounding systems in the pressure-temperature space (Figure 2).

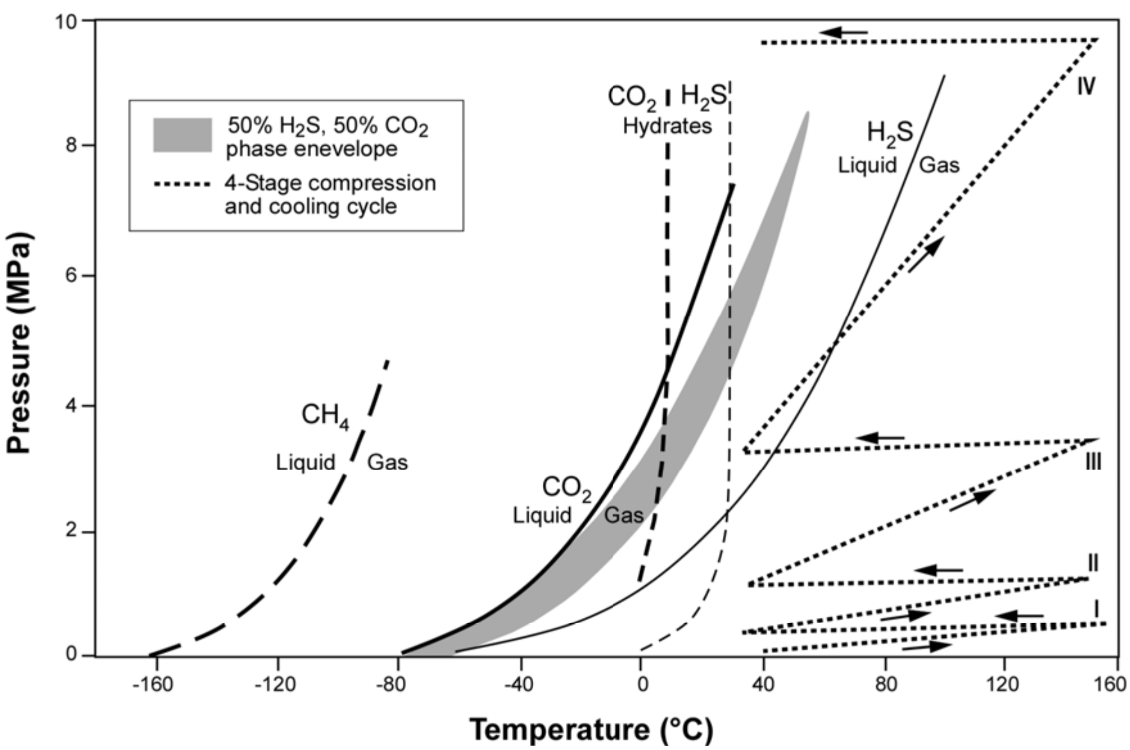


Figure 2. Phase diagrams for methane (CH_4), carbon dioxide (CO_2), hydrogen sulphide (H_2S) and a 50%-50% acid gas mixture; hydrate conditions for CO_2 and H_2S (after Wichert and Royan, 1996, 1997). A four-stage compression and cooling cycle is also shown.

If water is present, both CO_2 and H_2S form hydrates at temperatures up to 10°C for CO_2 and more than 30°C for H_2S (Carroll and Lui, 1997). If there is too little water, the water is dissolved in the acid gas and hydrates will generally not form. However, phase diagrams show that hydrates can form without free water being present (Carroll, 1998a, b), thus, operating above the hydrate-forming temperature is desirable. Unlike the case of hydrocarbon gases, the solubility of water in both H_2S and CO_2, hence in acid gas, decreases as pressure increases up to 3-8 MPa, depending on temperature, after which it dramatically increases (Figure 3). The solubility minimum reflects the pressure at which the acid gas mixture passes into the dense liquid phase, where the solubility of water can increase substantially with increasing pressure due to the molecular attraction between these polar compounds (Wichert and Royan, 1996, 1997).

The properties of the acid gas mixture are important in facility design and operation because, to optimize storage and minimize risk, the acid gas needs to be injected: (1) in a dense-fluid phase, to increase storage capacity and decrease buoyancy; (2) at bottom-hole pressures greater than the formation pressure, for injectivity; (3) at temperatures generally greater than 35°C to avoid hydrate formation, which could plug the pipelines and injection wells; and (4) with water content lower than the saturation limit, to avoid corrosion.

After separation, the water-saturated acid-gas stream leaves the regeneration unit at 35 to 70 kPa and must be cooled and then compressed for injection to pressures in excess of the subsurface storage formation pressure. Typically, four stages of compression are required to provide the required discharge pressure. By the fourth stage in a cycle, compression up to a maximum pressure between 3 and 5 MPa will tend to dewater the acid gas (Figure 3), if there are no hydrocarbon impurities present. Further compressing the acid gas to higher pressures increases the solubility of water in the acid gas, such that any residual excess water dissolves into the acid gas, and more than counteracts the decrease in solubility due to inter-stage cooling. To avoid pump cavitation, the acid gas must not enter the two-phase region during compression. Once the acid gas is compressed, it is transported through a pipeline to the injection wellhead located usually a short distance from the gas plant. The high pressures after the fourth compression stage stabilize, upon cooling, the high-density liquid-phase of the acid gas.

A number of subsequent safety valves are installed; both in the well and in the surface facilities, to isolate the containment lines for the acid-gas injection system into small volumes. However, the release of even small volumes of acid gas can be harmful. Consequently, the operators are required to have a detailed emergency response plan (ERP) in case a leak occurs that may impact humans. An emergency planning zone, the EPZ (i.e., area of land which may be impacted by the release of H_2S), is defined around the sour gas facility.

2.2 Criteria for Site Selection

The general location of an acid-gas injection well is often influenced by the proximity to sour oil or gas production facilities that are the source of acid gas. The specific location is based on a general assessment of the regional geology and hydrogeology, which is designed to evaluate the potential for containment and avoidance of leakage (Longworth *et al*., 1996) and which includes

1. Size of the injection zone, to confirm that it is large enough to volumetrically hold all of the injected acid gas over the lifetime of the project;
2. Thickness and extent of the overlying confining layer (caprock), and any stratigraphic traps or fractures that may affect its ability to contain the acid gas;
3. Location and extent of the underlying or lateral bounding formations;
4. Folding or faulting in the area, and an assessment of seismic (neotectonic) risk;

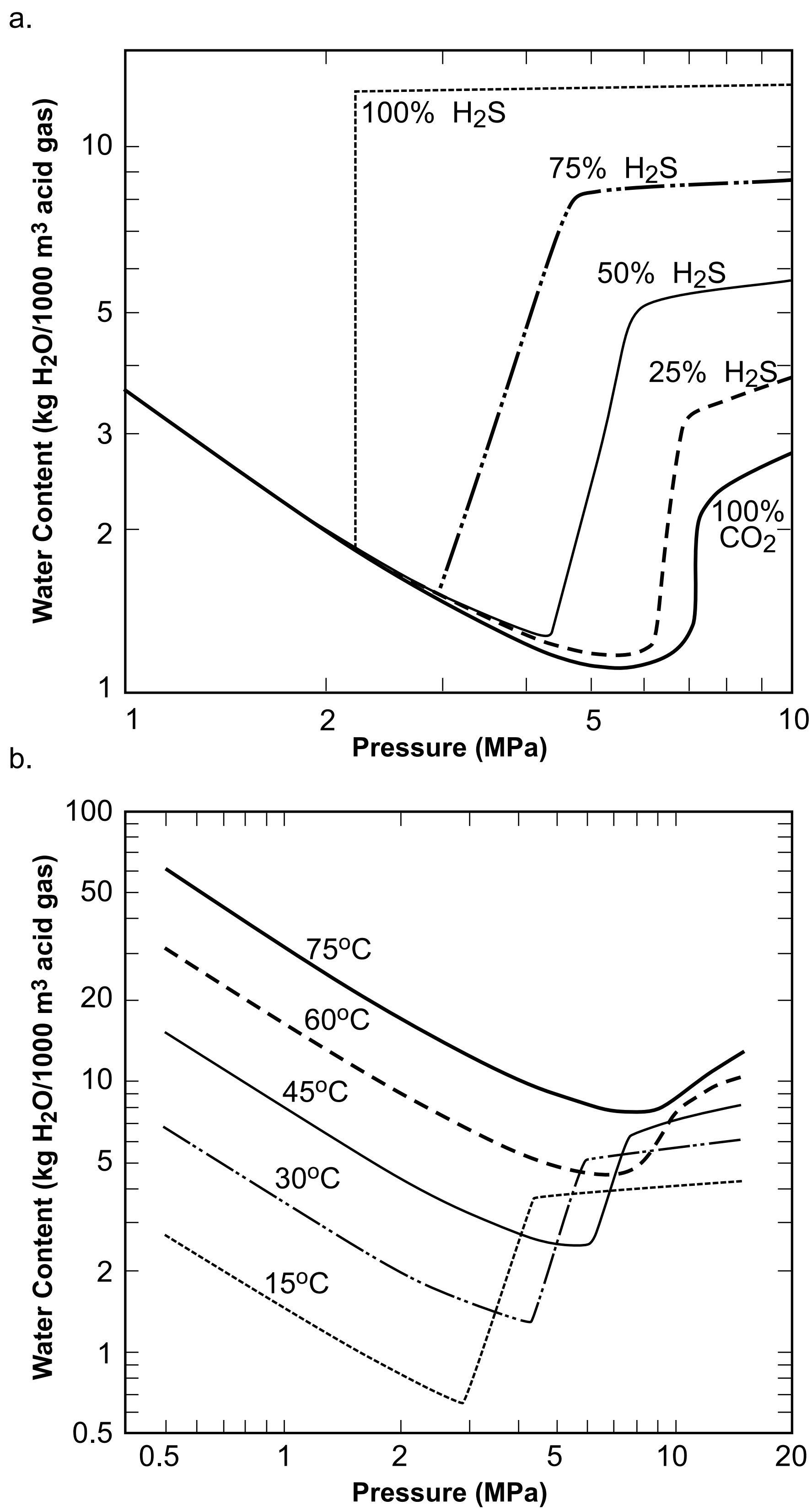


Figure 3. Solubility of water in acid gas as a function of pressure for: a) different acid-gas compositions (CO_2 and H_2S) at 30 C and b) different temperatures for an acid gas with a composition of 49% CO_2, 49% H_2S and 2% CH_4 (see also Lock, 1997; Wichert & Royan, 1996, 1997).

5. Rate and direction of the natural flow system, to assess the potential for migration of the injected acid gas;
6. Permeability and heterogeneity of the injection zone;
7. Chemical composition of the formation fluids (water for aquifers, oil or gas for reservoirs);
8. Formation temperature and pressure;
9. Analyses of formation and caprock drill core (if available); and, finally,
10. A complete and accurate drilling history of offsetting wells within several kilometres of the injection well, to identify any wells or zones that may be impacted by the injected acid gas.

Knowledge of the geological setting and characteristics is critical to assess the integrity of the host formation or reservoir, and the short- and long-term fate of the injected acid gas. Of particular importance are potential migration pathways from the injection zone to other formations, shallow groundwater and/or the surface. These potential pathways are of three types: the caprock pore space ("membrane" type), natural and/or induced fractures ("cracks") through the confining strata, and improperly completed and/or abandoned wells ("punctures"). To avoid diffuse gas migration through the caprock pore space, the difference between the pressure at the top of the injection aquifer or reservoir and the pressure in the confining layer must be less than the caprock threshold displacement pressure, which is the pressure needed for the acid gas to overcome the capillarity barrier and displace the water that saturates the caprock pore space. To avoid acid gas migration through fractures, the injection zone must be free of natural fractures, and the injection pressure must be below a certain threshold to ensure that fracturing is not induced. The maximum bottomhole injection pressure is set by regulatory agencies at less than 90% of the fracturing pressure of the reservoir rock. If injection takes place into a depleted oil or gas reservoir, the maximum bottom-hole injection pressure is usually set at no more than the initial reservoir pressure. From this point of view, injection into a depleted oil or gas reservoir has the advantages of injection pressures being low and of wells and pipelines being already in place (Keushnig, 1995). In the absence of site-specific tests, the pressures are limited by pressure-depth correlations, based on basin-wide statistical data for the Alberta Basin. An evaluation of the stress regime at the acid-gas injection sites in western Canada was performed to assess the relationship between the maximum allowed wellhead injection pressures and the rock fracturing threshold pressures (Bachu *et al*., 2004b). This study showed that maximum bottom hole injection pressures are well below the minimum horizontal stress, hence lower than the fracture pressure. Thus, there is no danger of opening existing fractures or of inducing new ones.

2.3 Issues

Critical issues are, for the most part, environmental and safety-related and they directly affect the economics of acid gas injection. Acid gas leaks can result in loss of life or contamination of the bio- and atmosphere. Surface safety is addressed through engineering, installation of safety valves and monitoring systems, and emergency procedures for the case of H_2S leaks. Subsurface issues are of two inter-related categories: the effect of the acid gas on the rock matrix and well cements, and plume containment.

When the acid gas contacts the subsurface formation, it will readily dissolve in the formation water in an aquifer, or connate water in a reservoir, and create weak carbonic and sulphuric acids. This leads to a significant reduction in pH that accelerates water-rock reactions. Depending on mineralogy, mineral dissolution or precipitation may occur, affecting the porosity and permeability of the host rock. The fact that both CO_2 and H_2S are dissolving in the formation water leads to some complex reaction paths where carbonates precipitate and dissolve, and pyrite/pyrrhotite precipitates (Gunter *et al*., 2000; Hitchon *et al*., 2001). Dissolution of some of the rock matrix in carbonate strata, or of the carbonates surrounding the sand grains in sandstone units results in lower injection pressures in the short term as a result of increased permeability. A major concern with the injection process is the potential for formation damage and reduced injectivity in the vicinity of the acid gas scheme. The reduction in injectivity could possibly be the result of fines migration, precipitation and scale potential, oil or condensate banking and plugging, asphaltene and elemental sulphur deposition, and hydrate plugging (Bennion *et al*., 1996).

Cement compatibility with the acid gas, primarily in the injection well, but also in neighbouring wells, is crucial for safety and containment. For example, a non-carbonate and calcium cement blend shattered when tested in an acid gas and in a CO_2 stream for several weeks (Whatley, 2000; Scherer *et al*., 2004). Thus, the compatibility of the acid gas with the cement that bonds the casing to the formation must be tested at a minimum. While the cement for the newly implemented acid-gas operation can be tested and properly selected prior to drilling, the cements in nearby wells are already in place and their condition is largely unknown. Some of these wells could be quite old (several decades), with the cement already in some stage of degradation as a result of brine composition. The acid gas, when reaching these wells, may enhance and speed up the cement degradation, leading to possible leaks through the well annulus and/or along casing.

If the acid gas is injected into the originating or other oil or gas pool, the main concern is the impact on further hydrocarbon recovery from the pool and acid gas production at the wellhead, although the injection operation and enhanced oil recovery may prove successful, like in the case of the Zama X2X pool (Davison *et al*., 1999). In fact, this operation has been proven so successful, that Apache Canada Ltd. applied in 2004 for acid-gas miscible flooding of the Zama Z3Z pool for enhanced oil recovery and intends to use acid-gas enhanced oil recovery at several other pools over the coming years. If the gas mixture is injected into an aquifer, the degree to which it forms a plume and migrates from the injection well depends on various factors, including pressure and temperature, solubility, interplay between driving forces like buoyancy and aquifer hydrodynamics, and aquifer heterogeneity, which controls gravity override and viscous fingering.

The fate of the injected acid gas in the subsurface is not known, because subsurface monitoring is not currently required and is difficult and expensive. Only the wellhead gas composition, pressure, temperature and rate have to be reported to the regulatory agency, EUB. Thus, a proper understanding of the geology and hydrogeology of the acid-gas injection unit (reservoir or aquifer) is critical in assessing the fate of the injected acid gas and the potential for migration and/or leakage into other units.

3 Basin-Scale Setting of Acid-Gas Injection Sites in the Provost Area

The six acid-gas injection operations, which are the subject of this report, are located in the southeastern part of the Alberta Basin (Figure 1). The Phanerozoic rock record consists of a southwestward thickening sedimentary wedge that reaches a thickness of over 6 km close to the limit of the disturbed belt of the Rocky Mountains (Wright *et al*., 1994). Towards the northeast, the sedimentary wedge laps onto the Canadian Shield, where it is terminated by erosion or non-deposition. The geology, stratigraphy and hydrostratigraphy of the sedimentary succession in the northern part of the Alberta Basin (north of the Peace River Arch) are different from those in the area south of the Peace River Arch, because of differences in the tectonostratigraphic evolution, with corresponding effects on the flow of formation waters (Bachu, 1999). In the following, the geology and hydrostratigraphy of the Alberta Basin will be presented, putting emphasis on central and southern Alberta (Figure 4). The geology described herein is based on Porter *et al*. (1982), Ricketts (1989) and Mossop and Shetsen (1994) (and references cited therein), and the hydrogeology follows work by Bachu (1997, 1999).

Of the six acid-gas injection operations in the Provost area, one injects into the Devonian Elk Point Group (Keg River Formation), two into the Devonian Woodbend Group (Leduc Formation), one into the Devonian Wabamun Group, and two into the Lower Cretaceous Mannville Group (Figure 4). Therefore, the Elk Point, Woodbend, Wabamun and Mannville groups will be discussed in more detail within the basin-scale framework.

3.1 Basin Geology and Hydrostratigraphy

The Alberta Basin sits on a stable Precambrian platform and is bound by the Rocky Mountain Trench to the west and southwest, the Tathlina High to the north and the Canadian Precambrian Shield to the northeast (Figure 1). The Bow Island Arch separates the Alberta Basin from the Williston Basin to the southeast. The basin was initiated during the late Proterozoic by rifting of the North American craton. It consists at the base of a Middle Cambrian to Middle Jurassic passive-margin succession dominated by shallow-water carbonates and evaporites with some intervening shales (Porter *et al*., 1982). From the Late Jurassic to Early Tertiary, accretion of allochthonous terranes to the western margin of the proto North American continent during the Columbian and Laramide orogenies pushed sedimentary strata eastward, resulting in the Rocky Mountains thrust and fold belt, and creating conditions for foreland-basin development east of the deformation front. Because of lithospheric loading and isostatic flexure, the Precambrian basement tilted westward, with a gentle slope of <4 m/km in the east near the Canadian Shield, becoming steeper westward, up to >20 m/km near the deformation front. As a result of this tilting and significant pre-Cretaceous erosion, progressively older Jurassic to Middle Devonian strata subcrop from west to east at the sub-Cretaceous unconformity. Deposition during the foreland stage of basin development was dominated by synorogenic clastics, mainly muds and silts, derived from the evolving Cordillera. The basin fill attained maximum thickness and burial during the Laramide orogeny in the Paleocene. Tertiary-to-Recent erosion since then has removed an estimated 2000 to 3800 m of sediments in the southwest (Nurkowski, 1984, Bustin, 1991). As a result of these depositional and erosional processes, the undeformed part of the Alberta Basin comprises a wedge of sedimentary rocks that increases in thickness from zero at the Canadian Shield in the northeast to close to 6000 m in the southwest at the thrust and fold belt. The present-day topography of the undeformed part of the basin has a basin-scale trend of decreasing elevations from highs in the 1200 m range in the southwest to lows around 200 m in the north-northeast at Great Slave Lake, which is the lowest topographic point in the basin. The

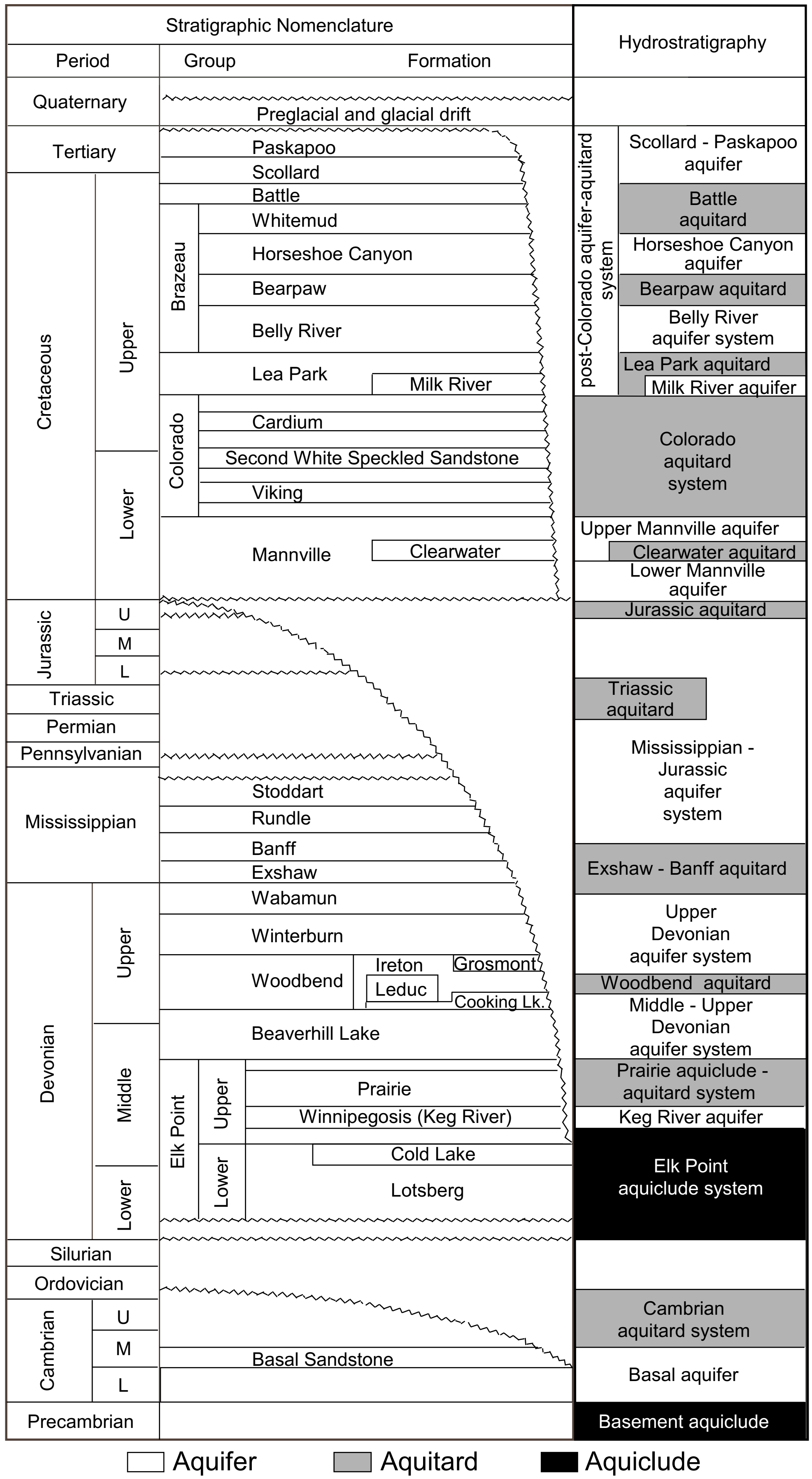


Figure 4. Basin-scale stratigraphic and hydrostratigraphic delineation and nomenclature for the southern and central parts of the Alberta Basin (after Bachu, 1999).

stratigraphic and hydrostratigraphic nomenclature and delineation for the entire sedimentary succession in the Alberta Basin south of the Peace River Arch are shown in Figure 4.

Hydrostratigraphically, the Precambrian crystalline basement constitutes an aquiclude, except possibly for fault and shear zones that may have served as conduits for fluid flow and may still be active today. Thin, diachronous basal sandstone units (Basal Sandstone in the south and Granite Wash in the area of the Peace River Arch) cover the Precambrian basement. As a result of pre-Middle Ordovician erosional bevelling and of major pre-Middle Devonian erosion, Cambrian strata are eroded near the Peace River Arch. Ordovician strata are present only in the southeast along a narrow band along the basin edge, and Silurian strata are completely absent. The Cambrian Basal Sandstone unit forms the Basal Cambrian aquifer, while the shale-dominated Cambrian and Ordovician strata form the Cambrian aquitard system.

Lower to Middle Devonian strata of the Elk Point Group unconformably overlie the Cambrian and Ordovician units or Granite Wash detritus. Sandstones, redbeds and evaporites that were deposited in a stable, continental environment form the base of the Elk Point Group. Three marine transgressions and regressions during the early Middle Devonian led to the deposition of interbedded carbonates, evaporites and fine siliciclastics, the last regressive cycle being represented by widespread shallow-marine carbonates of the Keg River Formation and equivalent strata (i.e., Winnipegosis Formation). Although formally there is a distinction between the Keg River Formation in the northwest and the Winnipegosis Formation in the southeast, in this report , the name 'Keg River' will be used for both formations, because this term is commonly used in the petroleum industry in southeastern Alberta. Successive subsidence of the Elk Point Embayment coupled with a decrease in the production of carbonate sediment initiated vertical reef growth, leading to the formation of the Presqu'ile Barrier in the northern part of the Alberta Basin during the late Middle Devonian (Figure 5). The carbonate barrier caused restricted conditions of sedimentation to the south, and a thick succession of anhydrite and salt of the Muskeg and Prairie formations accumulated above the Keg River Formation during periods of low water level and excessive evaporation in the central and southern parts of the basin (Figure 5). During the subsequent rise in sea level, reefal growth represented by the Sulphur Point Formation continued in the north, while nearshore, deltaic and lagoonal siliciclastics were deposited in the central part of the basin (Gilwood and Watt Mountain formations), and fossiliferous carbonates of the Dawson Bay Formation prograded from the east into the southern portion of the embayment.

The platformal and reefal carbonates of the Keg River Formation (Upper Elk Point Group) form the Keg River aquifer, whereas the overlying halite and other evaporites of the Prairie Formation followed by the shales of the Watt Mountain Formation form the Prairie aquitard-aquiclude system (Figure 4). Because of variable lithology (mixed siliciclastics and evaporites) of the Prairie Formation in the western part of the basin, and salt dissolution along the eastern basin edge, this hydrostratigraphic system has aquiclude characteristics where the salt is present and aquitard characteristics where the salt is absent, or present only in minor quantities. In the northern part of the Alberta Basin, the time-equivalent Sulphur Point/Presqu'ile Barrier reef complex forms a carbonate aquifer on top of the Keg River aquifer.

The Elk Point Group is unconformably overlain by the Middle Devonian Beaverhill Lake Group, which has been subdivided into the Fort Vermillion, Slave Point, Swan Hills, and Waterways formations. Reef growth occurred along the margins of the Slave Point platforms (e.g., fringing the Peace River landmass). The platformal and reefal carbonates of the Slave Point and Swan Hills formations together form the main aquifer unit within the Beaverhill Lake Group. The basinal deposits of the overlying Waterways Formation have, depending on location and dominant lithology, either aquifer or aquitard characteristics.

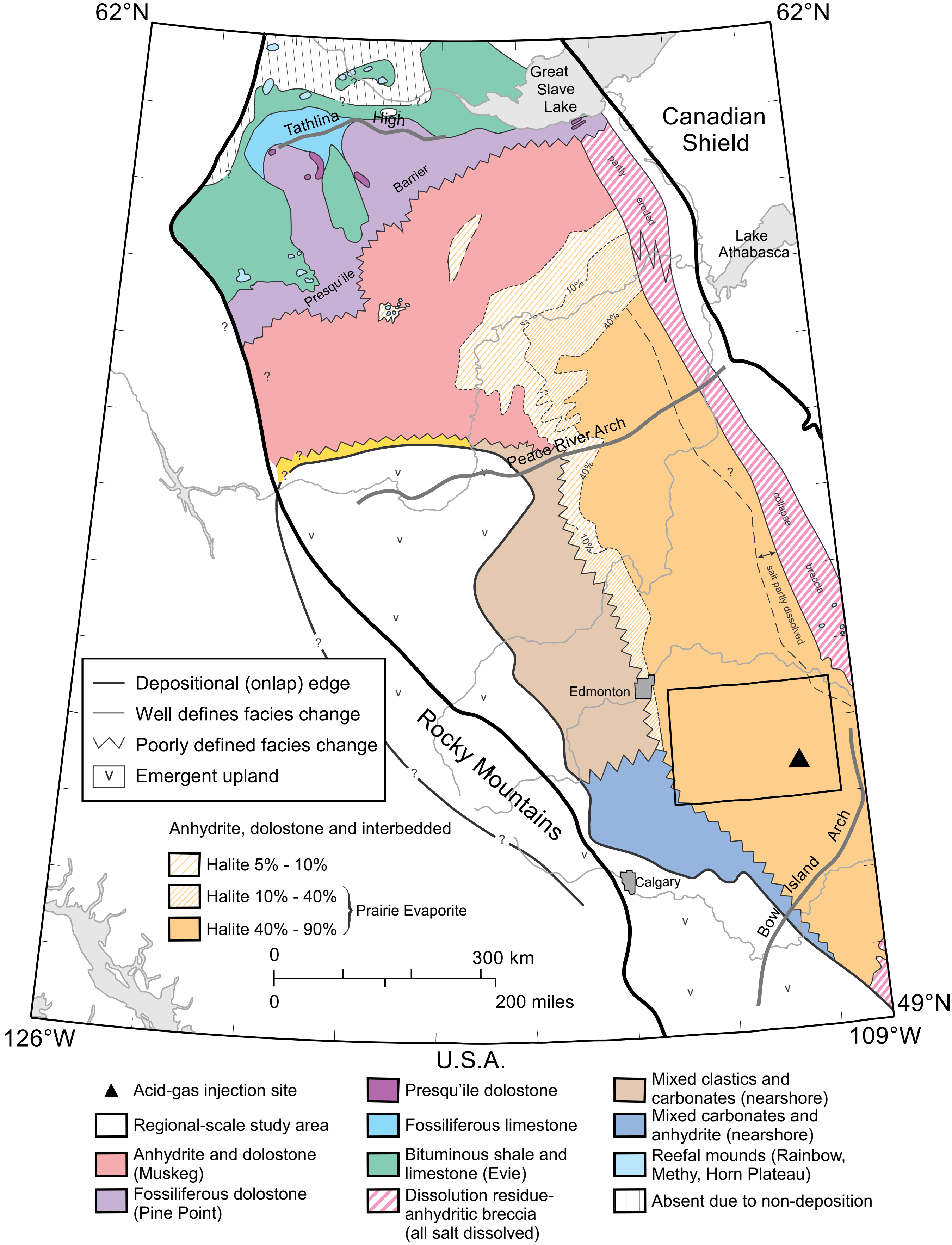


Figure 5. Upper Elk Point Group depositional environment and lithofacies assemblages in the Alberta Basin (after Meijer Drees, 1994). The location of the Provost Keg River injection site and the regional-scale study area is also shown.

The Upper Devonian Woodbend Group conformably overlies the Beaverhill Lake Group. Extensive platform carbonates and associated reefs of the Cooking Lake and Leduc formations developed in shallow water environments (Figure 6), while thick organic rich shales of the Majeau Lake Member (Cooking Lake Formation) and Duvernay Formation were deposited contemporaneously in deeper water settings. Calcareous shales and argillaceous limestones of the Ireton Formation progressively filled the basin from the northeast, thereby terminating Leduc reef growth. In northeastern Alberta, a large carbonate shelf platform, the Grosmont Formation (Figure 6), developed over the prograding Ireton Formation. Except for a small area in west-central Alberta, almost the entire basin had been filled in by the end of Woodbend Group deposition. In central Alberta, the basin-fill succession of the Woodbend Group differs significantly from that of the underlying Beaverhill Lake Group (Waterways Formation). Instead of being comprised of carbonate muds derived from coeval carbonate banks to the southeast and east, Woodbend Group basin-fill units have considerably higher clay shale content. All the units of the Woodbend Group subcrop at the sub-Cretaceous unconformity. The Grosmont Formation crops out along the Peace River at an elevation of approximately 250 m (Figure 6).

Hydrostratigraphically, the Cooking Lake and Leduc carbonates form the Cooking Lake aquifer, which, together with the aquifers of the underlying Beaverhill Lake Group, form the Middle-Upper Devonian aquifer system (Figure 4). The Ireton, Duvernay and Majeau Lake formations form the Woodbend aquitard. The Grosmont Formation is an aquifer that is included in the overlying Upper Devonian aquifer system as a result of its hydraulic continuity with and influence on the Winterburn and Wabamun aquifers in the area of subcrop in the northeastern part of the Alberta Basin (Anfort *et al.,* 2001).

The Woodbend Group is conformably overlain by the Winterburn Group, which has been subdivided into the Nisku, Calmar and Graminia formations. The Nisku Formation at the base of the Winterburn Group is comprised of fossiliferous shelf and reef carbonates in southern and northeastern Alberta with a transition to more open-marine, deeper-water carbonates and shales in west-central Alberta. It is followed by widespread dolomitic silts and shales of the Calmar Formation. The overlying Graminia Formation consists of the transgressive shallow shelf carbonates of the Blue Ridge Member and a northwestward thickening wedge of “Graminia Silt”, which marks the final infilling of the basin at the end of Winterburn time (Burrowes and Krause, 1987).

The Winterburn Group is conformably overlain by carbonates and evaporites of the Wabamun Group. The Upper Devonian Wabamun Group extends from southern Alberta to northern Alberta and British Columbia (Figure 7) and marks a re-flooding of the Alberta Basin following the Winterburn cycle of basin fill. At the initiation of the cycle, the underlying Winterburn succession had in-filled almost all of the pre-existing topography throughout most of Alberta. Therefore, the Wabamun Group is preserved as a rather monotonous package of low-angle mud-dominated carbonate ramp sediments. The in-filling of the basin took place from the northwest, resulting in the deposition of basinal shales followed by thick limestone sequences in northern Alberta. The Wabamun Group becomes increasingly dolomitic and eventually anhydritic in southeastern Alberta and southwest Saskatchewan (Figure 7; Stoakes, 1992).

The widespread platform carbonates interspersed with minor shales of the Winterburn and Wabamun groups subcrop at the sub-Cretaceous unconformity, and, at the basin scale, form the Upper Devonian aquifer system (Figure 4). Reefs of the Leduc Formation breach the Ireton aquitard in places, thus establishing local hydraulic communication between the Middle-Upper Devonian aquifer system and the overlying Upper Devonian aquifer system, including the

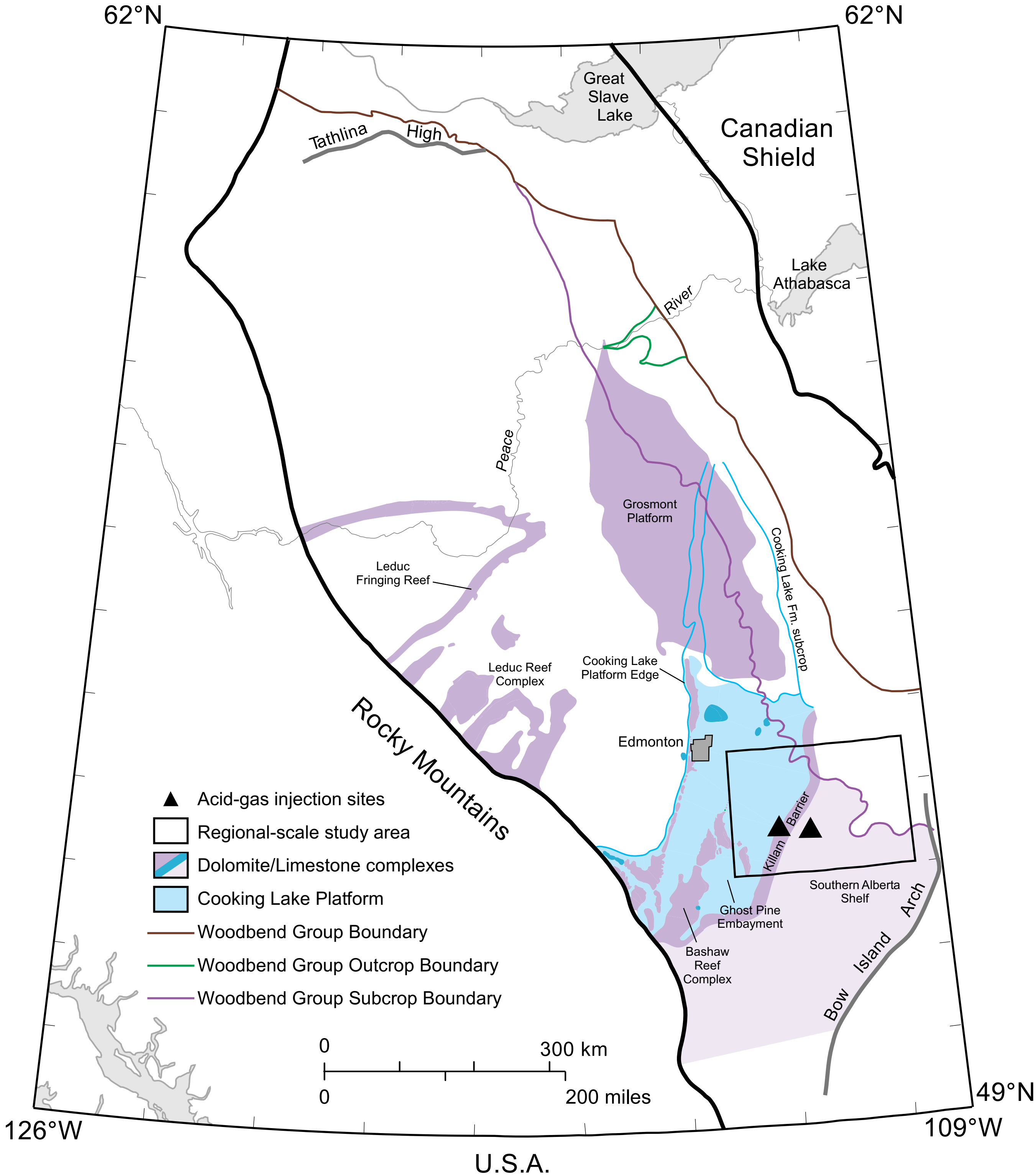


Figure 6. Depositional and erosional boundaries of the Woodbend Group, and outlines of Cooking Lake Formation platform carbonates, Leduc Formation reefs and Grosmont Formation platform carbonates (modified after Switzer *et al*. and Stoakes, 1992). The location of the Provost Leduc and Galahad Leduc injection sites and the regional-scale study area is also shown.

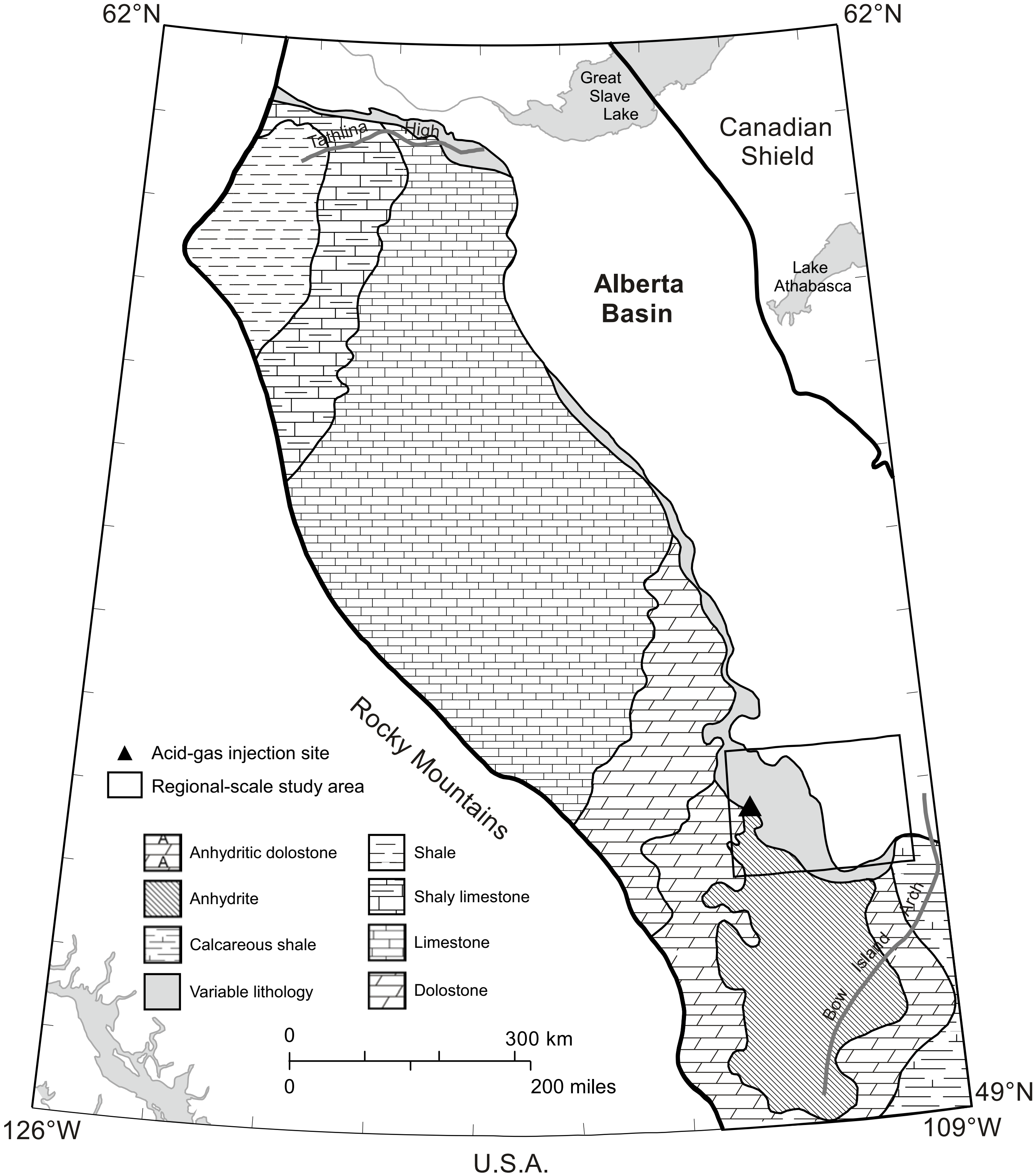


Figure 7. Lithofacies distribution of the Wabamun Group in the Alberta Basin (after Stoakes, 1992). The location of the Kelsey Wabamun injection site and the regional-scale study area is also shown.

Grosmont aquifer (Bachu and Underschultz, 1993; Rostron and Toth, 1996, 1997; Hearn and Rostron, 1997; Anfort *et al*., 2001).

The thin, organic rich, competent shales of the Exshaw Formation were conformably deposited on top of the Wabamun Group during the Late Devonian to Early Mississippian, followed by a succession of interbedded shales and carbonates of the Banff Formation, with an increase in the presence of carbonates toward the top. These are in turn overlain by thick carbonate successions of the Rundle and Stoddart groups. Permian, Triassic and early Jurassic strata are present only in the Peace River Arch area in the northwest near the eastern edge of the thrust and fold belt, and consist of interbedded sandstones, siltstones, carbonates, evaporites and shales. The shales of the Exshaw Formation and the shale-dominated lower part of the Banff Formation form the Exshaw-Banff aquitard (Figure 4). At the basin scale, the entire Upper Banff to Lower Jurassic succession, except for the Triassic, forms the Carboniferous-Jurassic aquifer system in the southern and central parts of the basin. The shales and evaporites that dominate the Triassic succession, including intervening sandstone units form the Triassic aquitard system.

Late Jurassic siliciclastics were deposited along the western edge of the basin at the beginning of the foreland-stage of basin evolution. They are variably dominated by either sandstones or shales, which form aquifers or weak aquitards, depending on location.

The overlying Cretaceous strata are divided into several depositional successions. The Mannville Group and age-equivalent strata are the oldest Cretaceous rocks over most of the Western Canada Sedimentary Basin and represent a major period of subsidence and sedimentation following a long time of uplift, exposure, and erosion of older strata (Figure 4). The Mannville Group strata, the depositional response to the Columbian orogeny (Porter *et al.*, 1982), consist of fluvial and estuarine valley-fill sediments as well as sheet sands and shales deposited by repeated marine transgressive-regressive events (Figure 8). The Lower Mannville Group was deposited over a broad unconformity surface cut by big valley systems. In the eastern part of the basin, northward flowing rivers occupied a network of incised valley systems, including the Spirit River and Edmonton valleys in Alberta and the Assiniboia Valley in Saskatchewan. These rivers drained the remainder of the foreland basin and discharged into the northern sea. The Cummings and Basal Quartz members, which are the injection targets within the Lower Mannville, were accumulated within these valleys, while the intervening highlands remained emergent (Figure 8). The sandstones in the western part of the basin throughout the Mannville interval are rich in quartz and chert and poor in igneous detritus, suggesting that they were derived from older, upthrust sedimentary rocks in the Cordilleran source area or more distant source areas. In the southern part of the basin, the Mannville Group forms at the basin-scale a single sandstone-dominated aquifer, while in the central-to-northern part, the Lower and Upper Mannville aquifers are separated by the intervening shale-dominated Clearwater aquitard (Figure 4). At a local scale, the lithology and therefore the hydrostratigraphy of the Mannville Group are much more complex, with lateral and vertical discontinuities caused by siliciclastic deposition in a fluvio-deltaic environment. The overlying Colorado Group was deposited during a lull in tectonic plate convergence when the basin was subject to a widespread marine transgression. Colorado strata consist predominantly of thick shales that form aquitards, within which there are isolated, thin, sandy units that form aquifers. Some of the sandstones, like those of the Viking and Cardium formations, are laterally extensive. Others are more restricted areally, like the Second White Speckled Sandstone, which is present only in the southern part of the Alberta Basin.

Post-Colorado Cretaceous and Tertiary strata were deposited during the Laramide orogeny and the subsequent period of tectonic relaxation, and consist of eastward-thinning nonmarine clastic wedges intercalated with argillaceous sediments. This cyclicity is developed best in the southern

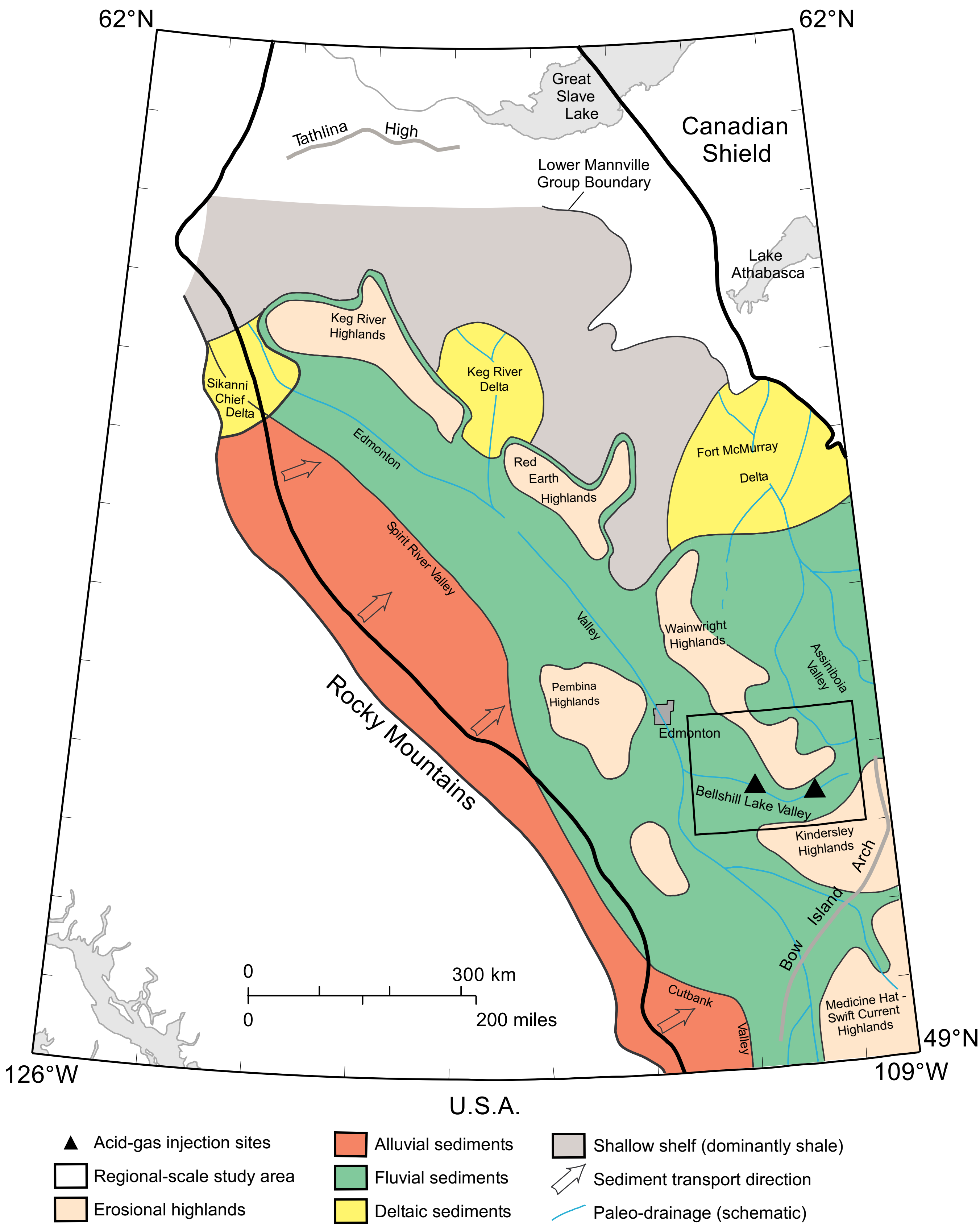


Figure 8. Paleogeography of the Alberta Basin during Cretaceous Lower Mannville time (after Smith, 1994). The location of the Bellshill Lake Blairmore and Hansman Lake Cummings injection sites and the regional-scale study area is also shown.

and southwestern parts of the basin, where the Milk River, Belly River, Horseshoe Canyon and Scollard-Paskapoo formations form the clastic wedges, and the Lea Park, Bearpaw, Whitemud and Battle formations comprise the intervening shales. In the central and northern parts of the basin, many of these cycles are absent due to either non-deposition or erosion. The clastic wedges form aquifers, while the intervening shales form aquitards. A variety of pre-glacial, glacial and post-glacial surficial deposits of Quaternary age overlie the bedrock over the entire basin.

3.2 Basin-Scale Flow of Formation Water

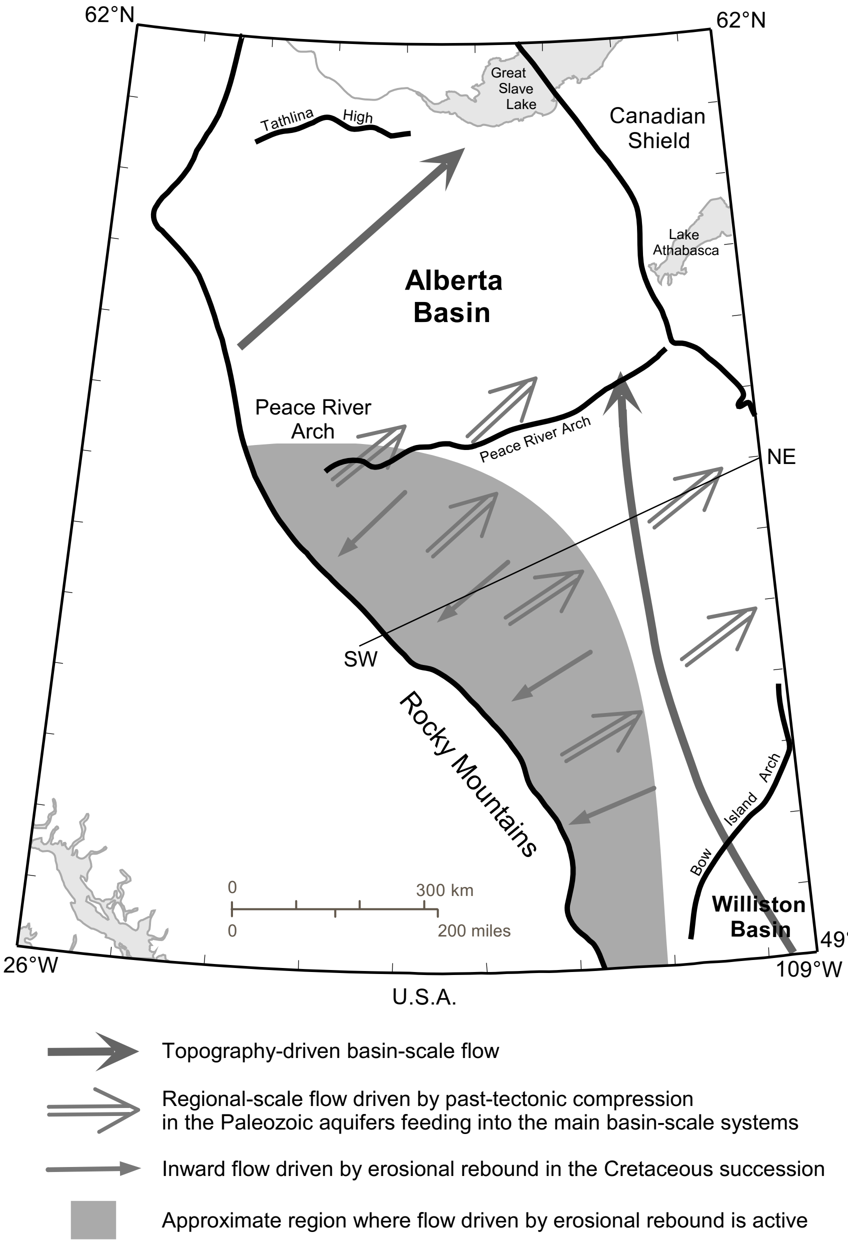
The flow of formation water in the Alberta Basin is quite well understood at the basin scale as a result of work performed over the last three decades by various researchers, starting with the pioneering work of Hitchon (1969a, b) and ending with a comprehensive summary and synthesis of previous work by Bachu (1999). The flow in the deformed part of the basin (the Rocky Mountains and the thrust and fold belt) seems to be driven by topography in local-scale systems. Recharge takes place at the surface throughout the entire system, with discharge as springs, in lakes and along river valleys. In most cases, fresh groundwater of meteoric origin discharges along various faults and thrust sheets, such as the Brazeau, Burnt Timber and McConnell, that separate the flow systems in the Rocky Mountain thrust and fold belt from the flow systems in the undisturbed part of the basin (Wilkinson, 1995; Grasby and Hutcheon, 2001). In the undeformed part of the Alberta Basin (from the eastern edge of the deformation front in the southwest to the edge of the exposed Precambrian Shield in the northeast), the flow regime is relatively complex due to basin evolution, geology, lithology and hydrostratigraphy, resulting in the interaction of various flow-driving mechanisms.

Topography-Driven Flow

The flow of formation water is driven by topography in local, intermediate, regional and basin scale systems, from regions of recharge at high elevations to regions of discharge at low elevations. A basin-scale flow system is recharged with fresh meteoric water in the south where Devonian, Carboniferous and Cretaceous aquifers crop out at high elevation in Montana. Water flows northward and discharges at outcrop of the Grosmont aquifer along the Peace River (Figure 9). The aquifers in this flow system are the Upper Devonian and Carboniferous-Jurassic in the region of respective subcrop at the sub-Cretaceous unconformity, the Grosmont, and the Lower Mannville. They all are in hydraulic contact in southeastern and central Alberta due to the absence of intervening aquitards as a result of pre-Cretaceous erosion (Figures 4 and 9). In this basin-scale flow system, low hydraulic heads corresponding to discharge areas propagate far upstream, inducing widespread sub-hydrostatic pressures, as a result of high aquifer permeability downstream (Anfort *et al*., 2001).

An intermediate-scale flow system driven by topography is present in the Athabasca region, where meteoric water recharges at relatively high elevations in the Birch and Pelican mountains, penetrates down to the Slave Point (Beaverhill Lake Group) aquifer and discharges at low-elevation outcrop along the Athabasca, Peace and Hay rivers (Bachu and Underschultz, 1993; Bachu, 1999). All aquifers and aquitards in the Upper Devonian to Jurassic succession are absent in this area due to pre-Cretaceous erosion (Figures 4 and 8). The Slave Point and Keg River aquifers in northeastern Alberta are in an intermediate position between regional-scale flow in the western part of the basin, and local-scale flow systems close to the basin's eastern edge (Hitchon *et al*., 1990; Bachu and Underschultz, 1993).

a.



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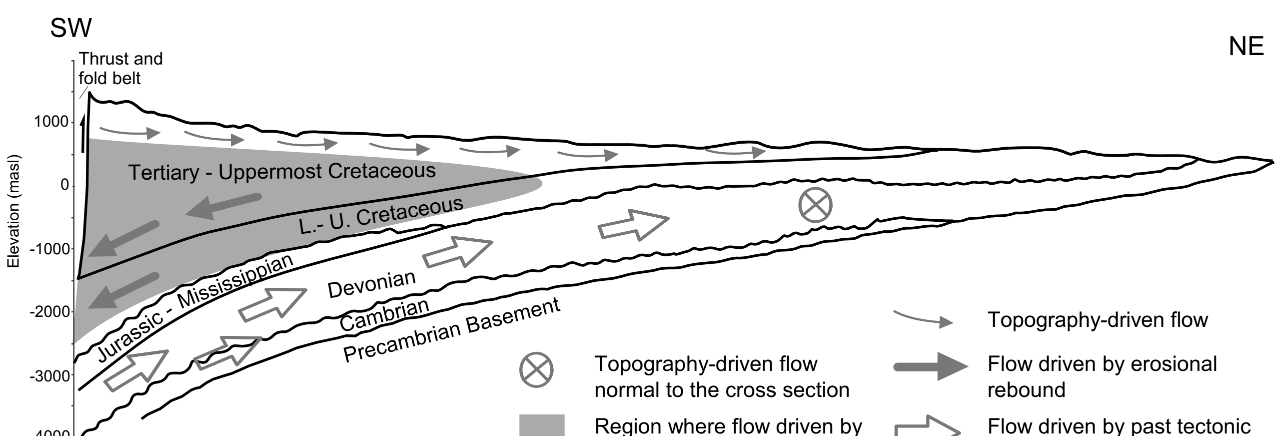


Figure 9. Diagrammatic representation of flow systems and hydrostratigraphy in the Alberta Basin: a) in plan view and b) in cross-section (after Bachu, 1999).

Local-scale flow systems are present throughout the entire basin in the shallower strata. Fresh meteoric water is driven from local topographic highs, such as the Swan Hills, Cypress Hills and Pelican Mountains, to the nearest topographic lows, usually a river valley. Such local flow systems were identified in the Upper Cretaceous - Tertiary strata in the south, southwest and west (Toth and Corbet, 1986; Michael and Bachu, 2001), and in the Red Earth and Athabasca regions (Toth, 1978; Bachu and Underschultz, 1993).

Flow Driven by Erosional and/or Post-Glacial Rebound

During sediment loading, water flows vertically in compacting sand-shale successions, out of overpressured shaly aquitards into the adjacent sandstone aquifers (expulsion), then laterally in the sandstones, outward toward the basin edges. Directions of water movement are reversed during erosional unloading, with transient effects lasting for long periods of time in rocks characterized by very low hydraulic diffusivity. Significant underpressuring in shales drives the flow of formation waters in the intervening aquifers laterally inward from the permeable basin edges, and vertically into the rebounding shaly aquitards ("suction"). This type of flow is present at both local and large scales in the southern and southwestern part of the Alberta Basin in the siliciclastic Mannville, Viking, Second White Speckled Sandstone, Belly River and Horseshoe Canyon aquifers in the Cretaceous succession (Figures 4 and 9) (Toth and Corbet, 1986; Parks and Toth, 1993; Bachu and Underschultz, 1995; Anfort *et al*., 2001; Michael and Bachu, 2001). The flow is driven by erosional and post-glacial rebound in the thick intervening shales of the Colorado Group, and Lea Park, Bearpaw and Battle formations, as a result of up to 3800 m of sediments having been eroded in the area since the peak of the Laramide orogeny some 60 My ago (Nurkowski, 1984; Bustin, 1991), and following the retreat of 2 km thick Laurentide ice sheets since the Pleistocene. The flow in these Cretaceous aquifers is in a transient state, driven inward from the aquifers' eastern boundary to the west-southwest, downdip toward the thrust and fold belt. The aquifers are severely underpressured in places, with corresponding hydraulic heads being less than 200 m close to the thrust and fold belt (Bachu *et al*., 2002; Michael and Bachu, 2001). These hydraulic heads are lower than the lowest topographic elevation in the basin at Great Slave Lake more than 1500 km away in the northeast.

Hydrocarbon-Saturated "Deep Basin"

During the process of hydrocarbon generation, the phase change of solid kerogen that fills the pore space into fluid hydrocarbons leads to volumetric expansion and generation of internal stresses that create overpressures capable of displacing formation water from the pore space and driving flow (Hedberg, 1974; Osborne and Swarbrick, 1997). However, the overpressures caused by active hydrocarbon generation can be maintained only if the respective reservoirs are well sealed by very low permeability rocks. Burial of the basin strata and subsequent hydrocarbon generation during the Laramide orogeny created dominantly hydrocarbon-saturated zones in the deeper parts of the Cretaceous to Triassic strata, the hydrocarbons being located downdip of the water-saturated zones (Masters, 1984; Michael and Bachu, 2001). The water-saturated zone directly updip of the hydrocarbon-saturated zones is generally underpressured, suggesting that the rate of hydrocarbon leakage from the reservoir rocks presently exceeds the rate of hydrocarbon generation, and that formation water can re-imbibe these zones. Therefore, the hydrocarbon-water interface may be characterized as a transient relative permeability barrier that moves downdip towards the deformation front with the uplift of the basin. Overpressures are maintained in the deep parts of those hydrocarbon-saturated zones in which the rate of active thermogenic hydrocarbon generation is sufficiently high. Formation water flow in the Lower Cretaceous aquifers is mostly towards the receding hydrocarbon-saturated regions and towards the sinks created by erosional and post-glacial rebound of the intervening shales. In general, the hydrocarbon-saturated region represents a relative-permeability and pressure barrier with respect to lateral hydraulic communication within each aquifer, and to vertical cross-formational flow from underlying Paleozoic strata.

Tectonic Compression

Unlike compaction and erosion, which create vertical stresses in the fluid-saturated sedimentary succession, tectonic compression during orogenic events creates lateral stresses and pressure pulses that lead to water expulsion from the overridden and thrusted rocks into the foreland basin. These pressure pulses dissipate over several million years, depending on the hydraulic diffusivity of the sedimentary succession (Deming and Nunn, 1991). In the deep part of the Alberta Basin in the southwest, the flow of formation waters in the Devonian and Mississippian-Jurassic aquifer systems is northeastward updip until it reaches the sub-Cretaceous unconformity, where it joins the northward basin-scale gravity-driven flow system (Figure 9) (Hitchon *et al*., 1990; Bachu and Underschultz, 1993, 1995; Rostron and Toth, 1997; Anfort *et al*., 2001). In the deeper Basal Cambrian and Winnipegosis aquifers, the flow of formation waters is also northeastward updip to their respective northeastern boundary (Hitchon *et al*., 1990; Bachu and Underschultz, 1993). The salinity of formation waters in these aquifers generally increases southwestward downdip. (Hitchon *et al*., 1990; Bachu and Underschultz, 1993, 1995; Rostron and Toth, 1997; Anfort *et al*., 2001; Michael and Bachu, 2002; Michael *et al*., 2003). Up to their respective eastern erosional or depositional boundary, all of these aquifers are separated by intervening strong aquitards. Direct freshwater meteoric recharge from the surface of these aquifers in either the deformed or the undeformed parts of the basin in the southwest is not possible or is very unlikely for a variety of reasons (Bachu, 1999; Michael and Bachu, 2001, 2002; Bachu *et al*., 2002; Michael *et al*., 2003). Based on the high salinity of formation waters in the deep Paleozoic aquifers in the southwestern part of the basin, and because of the lack of an identified recharge source and mechanism, Bachu (1995) postulated that the flow in these aquifers is driven by past tectonic compression. This hypothesis is supported by isotopic analyses of formation waters and late-stage cements in both the deformed and undeformed parts of the basin (Nesbitt and Muehlenbachs, 1993; Machel *et al*., 1996; Buschkuehle and Machel, 2002).

Buoyancy

The flow of formation water is driven in the gravitational field by hydraulic gradients and by density differences (buoyancy). Generally, Paleozoic waters are more saline than Mesozoic waters (Hitchon, 1969a, b; Bachu, 1999; Anfort *et al*., 2001; Michael and Bachu, 2001, 2002; Michael *et al*., 2003). The increase in salinity is mild in Cretaceous strata, rather abrupt at the sub-Cretaceous unconformity, and steep in Paleozoic strata, particularly in the vicinity of evaporitic beds (Bachu, 1999). In southern Alberta, water salinity in Upper Devonian and Carboniferous aquifers is lower than in the central and northern parts of the basin and comparable with water salinity in Mesozoic aquifers, as a result of meteoric water recharge at outcrop in Montana (Anfort *et al*., 2001). The existence of high-salinity connate waters in the Paleozoic and Triassic strata shows that the basin has not yet been flushed of the original waters existing in the basin at the time of deposition. Thus, buoyancy, rather than generating or enhancing the flow of formation waters in the Alberta Basin, retards it, to the point of stagnation or sluggishness in some places. A zone of mixing between high-salinity Paleozoic waters and fresher water is present in the Lower Mannville aquifer in the south-central part of the basin, in the region where Devonian aquifers subcrop at the sub-Cretaceous unconformity (Bachu, 1995; Rostron and Toth, 1997; Anfort *et al*., 2001).

Cross-Formational Flow

Generally, there is little cross-formational flow in the Alberta Basin because of its “layer-cake” structure, where strong aquitards separate the major aquifers and aquifer systems in the sedimentary succession. Cross-formational flow takes place over large areas only where aquitards are weak. Such cases are the Clearwater and Watt Mountain aquitards in the northeast in the Athabasca area (Bachu and Underschultz, 1993), and the Calmar aquitard in the Upper Devonian aquifer system (Rostron and Toth, 1997; Anfort *et al*., 2001). Localized, direct cross-formational “pipe” flow between aquifers takes place across Devonian aquitards and aquicludes only in places where Keg River and Leduc reefs breach through the intervening shaly aquitards. Such “pipes” were identified between the carbonate platforms of the Woodbend Group and the Winterburn Group in the Cheddarville and Bashaw areas, and along the Rimbey-Meadowbrook reef trend (Bachu and Underschultz, 1993; Wilkinson, 1995; Rostron and Toth, 1996, 1997; Anfort *et al.*, 2001). Reefs of the Leduc Formation create a path for direct hydraulic communication across the Ireton aquitard between the underlying Leduc-Cooking Lake and overlying Upper Devonian aquifer systems. Otherwise, mixing of formation waters from different aquifers, and consequently of fresh meteoric and connate waters, takes place at the sub-Cretaceous unconformity in the area where various Devonian strata subcrop (Figure 9) (Hitchon *et al*., 1990; Bachu and Underschultz, 1993, 1995; Rostron and Toth, 1997; Anfort *et al*., 2001).

4 Regional-Scale Setting of the Provost Cluster of Acid-Gas Injection Sites

To better understand the geology, hydrogeology, formation water flow at the acid-gas injection sites in the Provost area, and the containment of the injected acid gas, a regional-scale study area was defined between 52.0°N, 109.5°W and 53.5°N, 113.0°W (approximately Township 37 to 52 and Range 2 to 16W4)(Figure 10). The study area is located southeast of Edmonton and straddles the Alberta-Saskatchewan border. The ground surface elevation decreases from approximately 915 m above sea level (a.s.l.) in the southwest in the area of the Cooking Lake Uplands to 520 m a.s.l. in the northeast (Figure 11). The main surface water drainage is towards the Battle River, which runs eastward through the center of the study area. The Red Deer River cuts through the very southwest corner of the study area.

Acid gas injection occurs in the Devonian Elk Point, Woodbend and Wabamun groups, and the Cretaceous Mannville Group (Figure 12), which will be the focus of this chapter. A major erosional event during Jurassic times resulted in the pre-Cretaceous unconformity along which Carboniferous to Upper Devonian formations subcrop below the Cretaceous Lower Mannville Group (Figure 13). The stratigraphic and structural relationships between various injection units are shown along an updip cross-section in Figure 14.

4.1 Geology of the Elk Point to Lower Mannville Groups

The Devonian carbonates of the Elk Point Group, the overlying Cooking Lake and Leduc formations of the Woodbend Group, and the carbonates of the Wabamun Group constitute the main Paleozoic acid-gas injection intervals in the Provost area.

4.1.1 Devonian Elk Point Group

The Middle Devonian Elk Point succession in the regional-scale study area is characterized by a sequence of siliciclastic rocks (Ashern Formation), platform and reef carbonates (Keg River Formation), as well as evaporites (Prairie Formation). Deposition took place in the Elk Point Basin, which formed behind the Presqu'ile barrier (Figure 5) and had its depocentre in south central Saskatchewan.

The Keg River Formation, the injection unit, was deposited during three depositional episodes. In the first episode a broad, uniform, normal marine environment was established following a hiatus. In the second episode, the Elk Point Basin differentiated into shallow carbonate platform and deeper basinal areas. The third episode was regressive and deposition was characteristic of high intertidal to supratidal environments (Perrin, 1982).

The Lower and Upper members of the Keg River Formation are platform and reef/inter-reef deposits, respectively (Figure 15). The Upper Keg River Member contains two main facies types: an inter-reef facies that consists of thin bituminous, laminated, inter-reef carbonate deposits and that, where well developed, can be subdivided into a lower bituminous carbonate unit and an upper finely laminated unit; and, a reefal facies forming thick mounds or reef complexes that grew in response to relative sea-level rise (Reinson and Wardlaw, 1972).

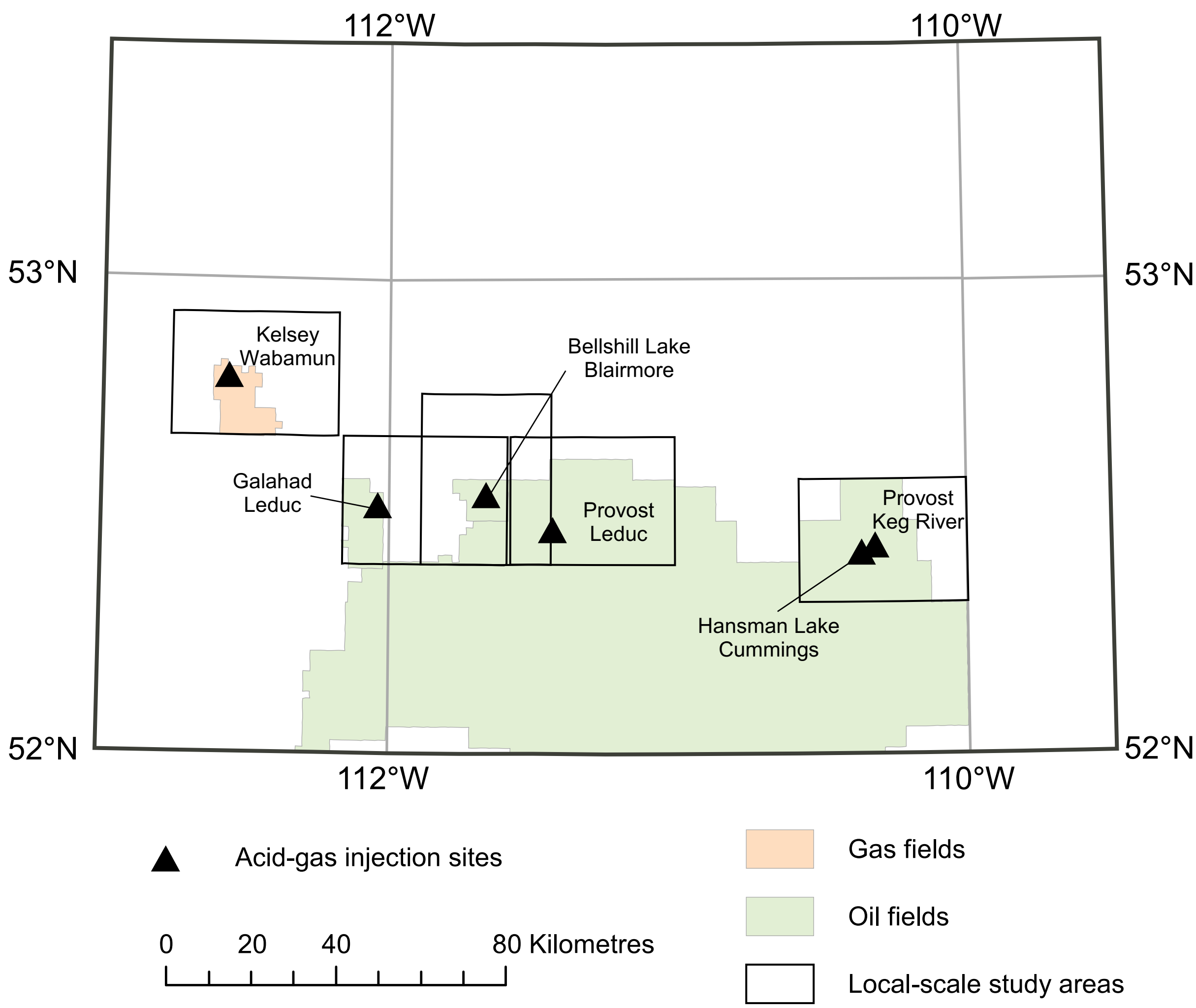


Figure 10. Location of acid-gas injection sites, major oil and gas fields, and local-scale study areas in the Provost regional-scale study area.

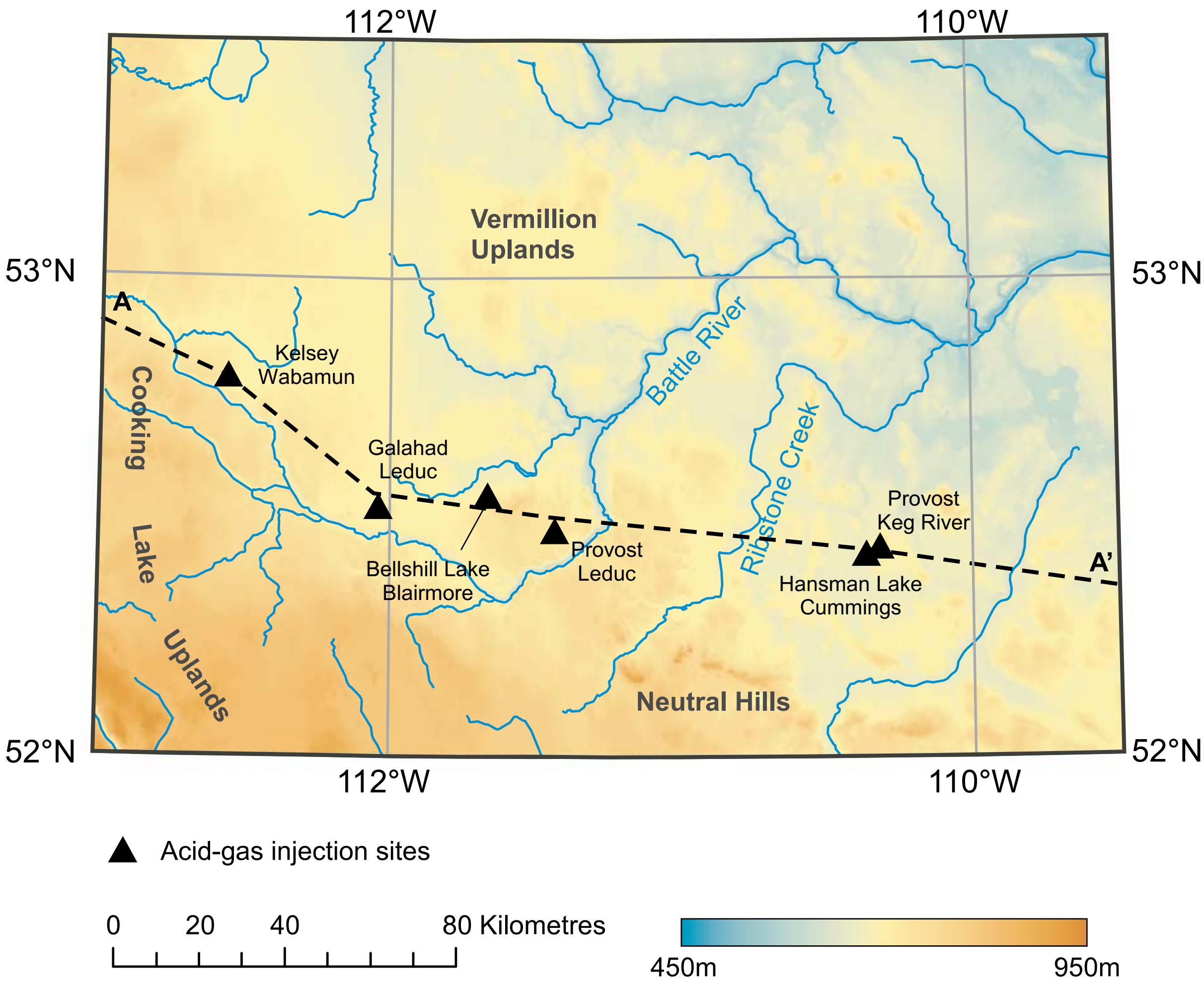


Figure 11. Topographic map of the regional-scale study area showing the location of the acid-gas injection sites. The line of cross-section A-A' is shown in Figure 14.

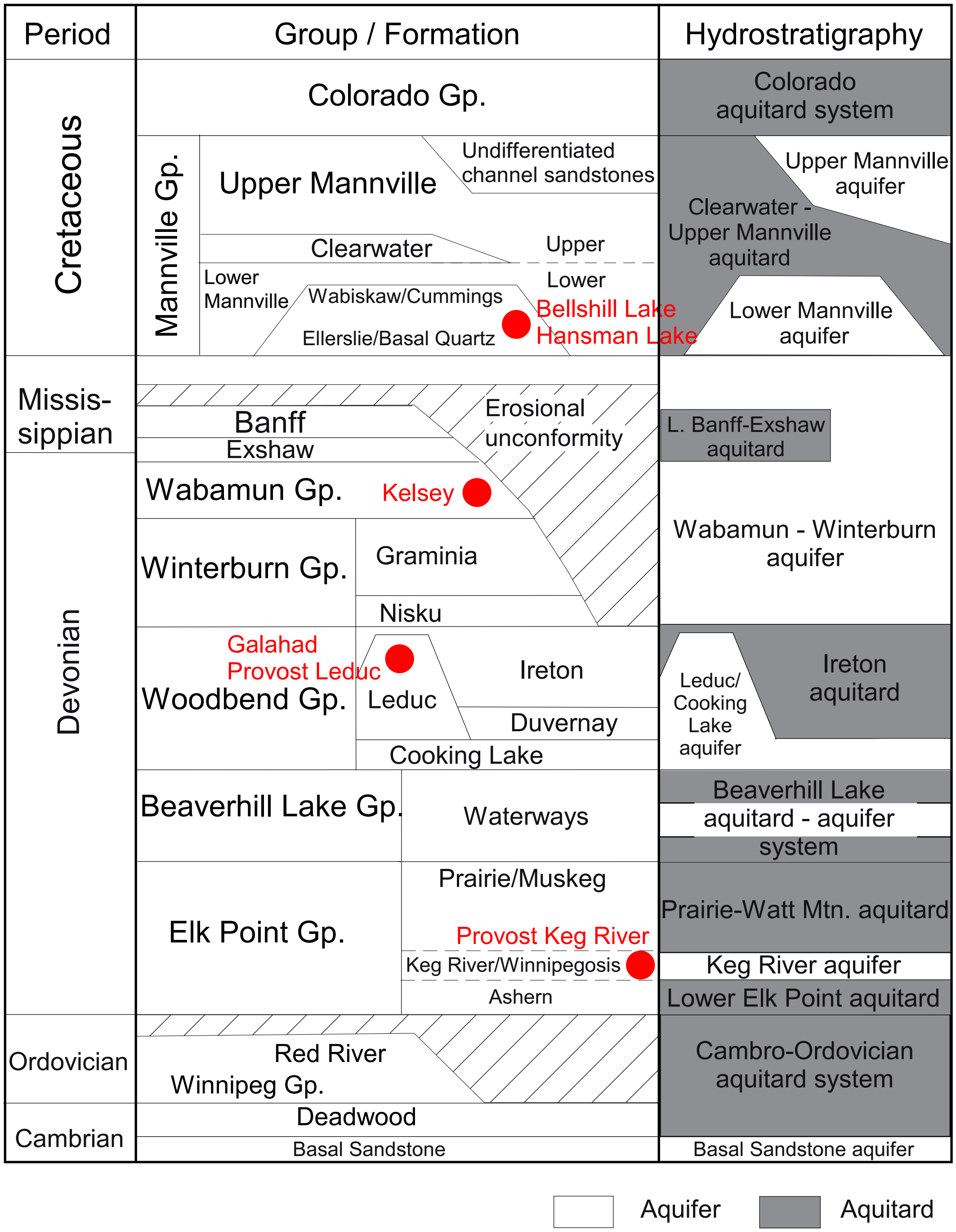


Figure 12. Stratigraphic and hydrostratigraphic delineation and nomenclature for the strata in the Cambrian - Upper Cretaceous succession in the regional-scale study area. Acid-gas injection horizons are indicated by red circles.

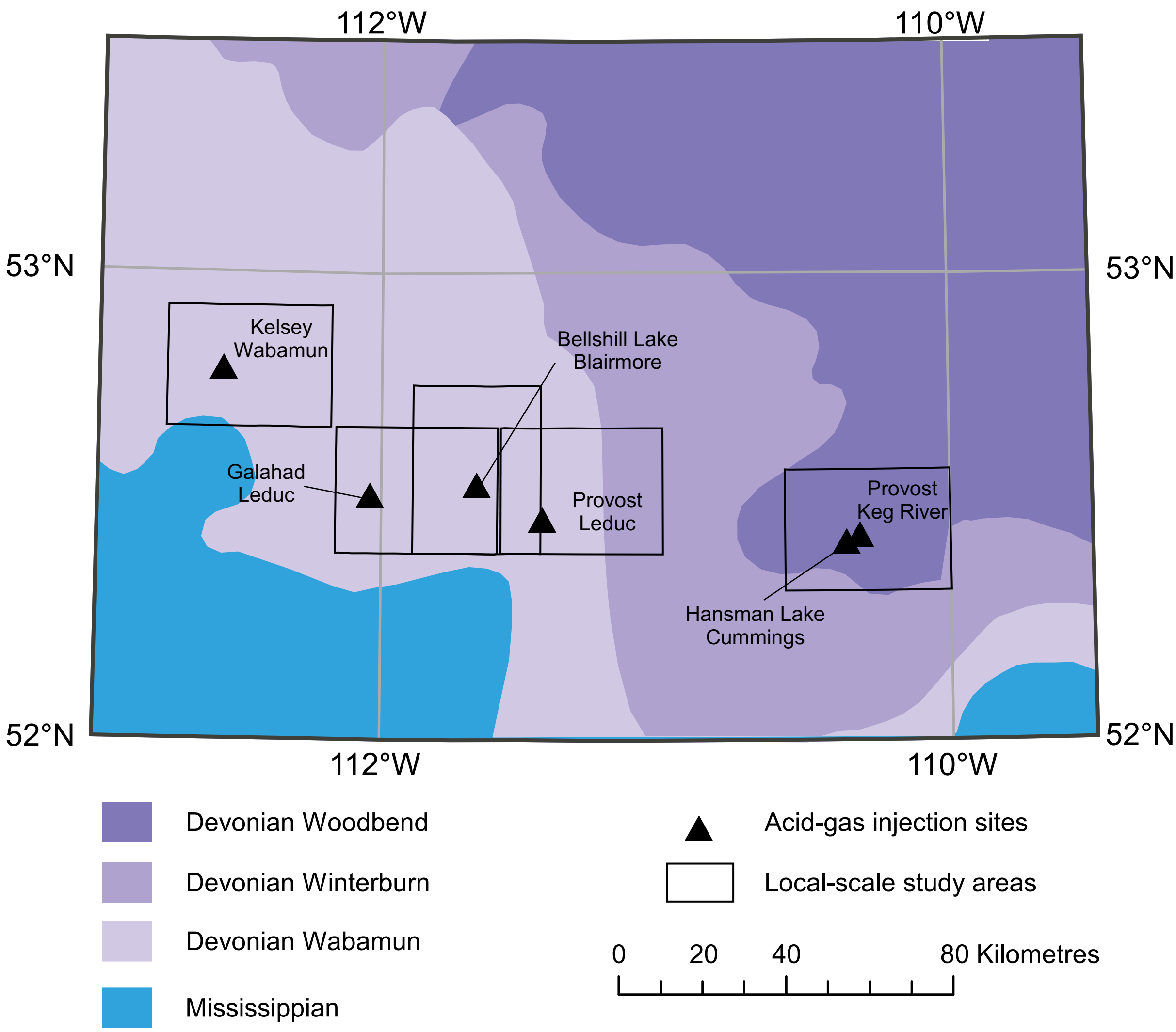


Figure 13. Subcrop of the Paleozoic strata along the sub-Cretaceous unconformity in the regional-scale study area (after Hayes *et al.*, 1994). The location of the injection sites and the local-scale study areas is also shown.

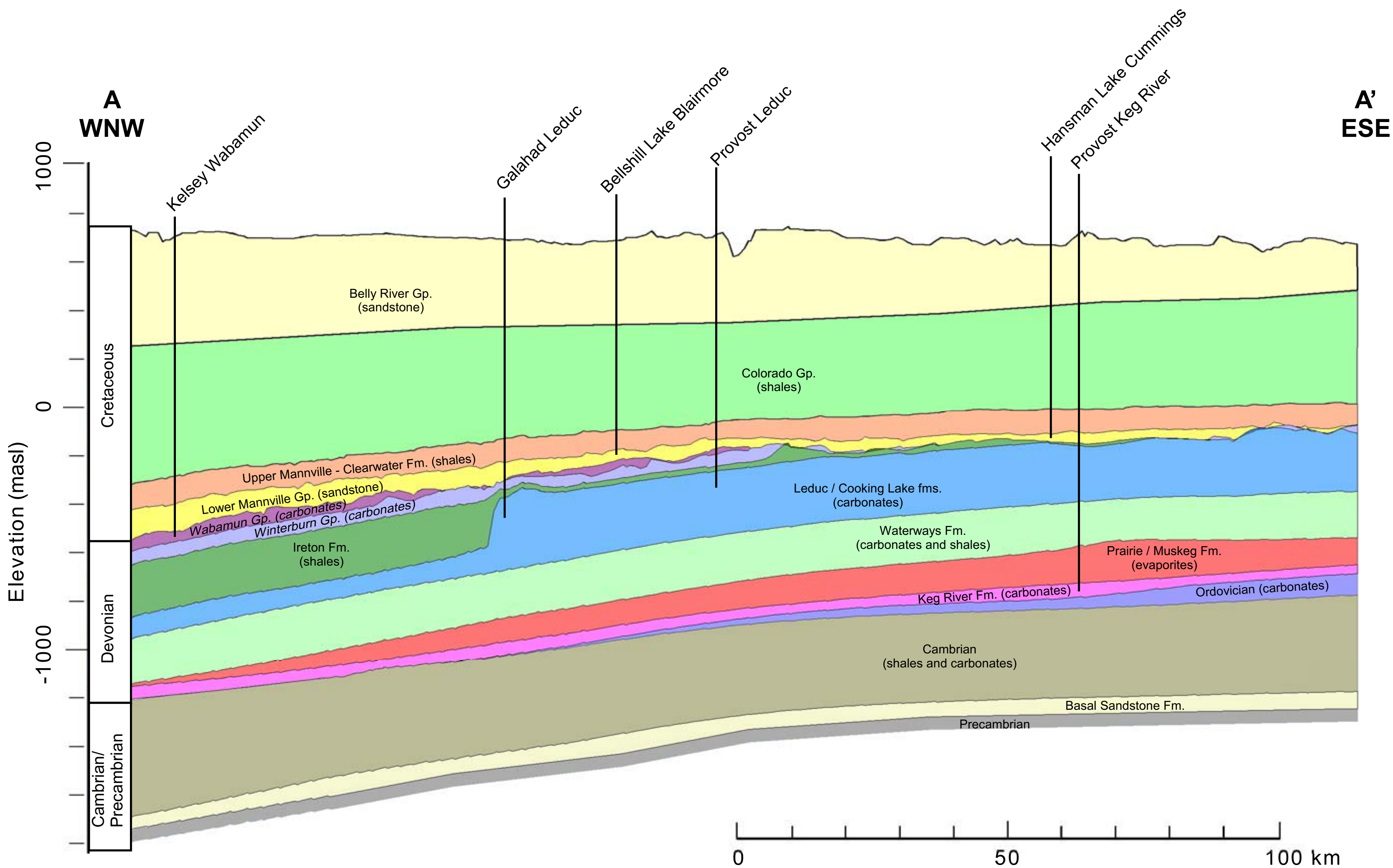


Figure 14. Stratigraphic cross-section through the regional-scale study area showing the relative position of the various target horizons in the Devonian to Cretaceous succession for acid gas injection in the Provost area. The location of the cross-section is shown in Figure 11.

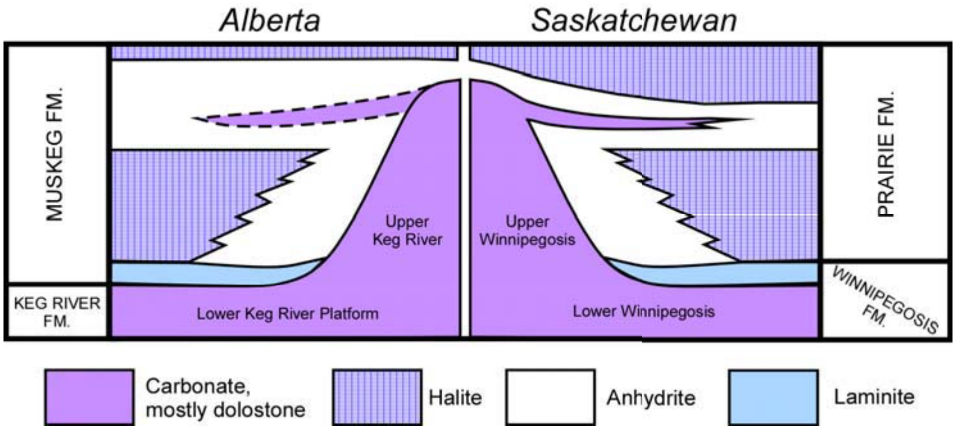


Figure 15. Stratigraphic correlations and equivalencies across the Alberta/Saskatchewan border within the Keg River/Muskeg depositional succession (modified after Moore, 1989).

The depth to the top of the Keg River Formation in the regional-scale study area ranges between more than 2200 m in the southwest, to less than 1000 m in the northeast (Figure 16a). The Keg River Formation has an average thickness of 20 m in most of the area. The top surface of the Keg River Formation dips southwestward from elevations of -400 m in the northeast to -1300 m in the southwest with a slope of about 4.3 m/km (Figure 16b).

Within the regional-scale study area, the Keg River Formation is conformably overlain by carbonates and evaporites of the Prairie Formation (Figure 14), which can reach thicknesses of up to 200 m and act as seal on top of the injection horizon. The Keg River Formation is underlain by greyish orange, unfossiliferous, slightly silty, argillaceous dolomite to dolomitic shale of the Ashern Formation, Ordovician dolostones and limestones or carbonates of the Cambrian System.

4.1.2 Devonian Woodbend Group

The Upper Devonian Woodbend Group consists of shallow-water carbonates of the Cooking Lake and Leduc formations (Figure 12), as well as deeper-water carbonates and shales of the Duvernay and Ireton formations.

The Cooking Lake Formation is present in the entire regional-scale study area (Figure 17) and, consists predominantly of shallow-water limestones, except for a dolomitized area along the north/south-trending Killam Barrier Reef edge. Areas where platform carbonates of the Cooking Lake Formation attain their greatest thickness (predominantly, but not exclusively, along the platform edge) often coincide with the location of overlying reefs of the Leduc Formation.

The depth to the top of the Cooking Lake Formation in the regional-scale study area ranges from more than 2000 m in the southwest to less than 700 m in the northeast. The top of the Cooking Lake Formation dips southwestward with a slope of about 4 m/km in the regional scale study area, from above -100 m in the northeast to -1100 m in the southwest. The average thickness of the Cooking Lake Formation is about 80 m. However, in places where the Cooking Lake Formation it is directly overlain by reefal and platform carbonates of the Leduc Formation, the boundary between the two formations is often indistinguishable, making it difficult to determine the individual thicknesses.

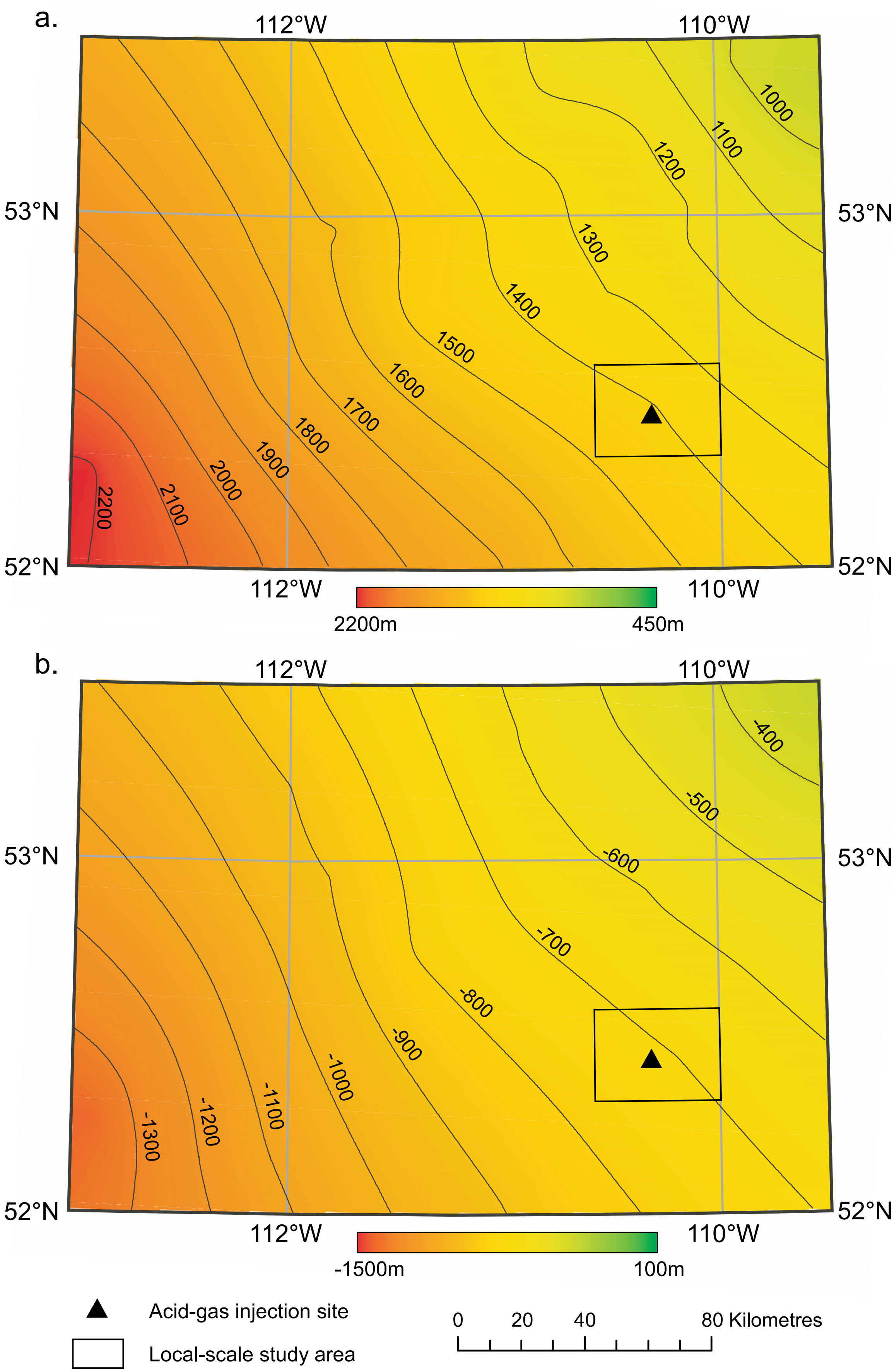


Figure 16. Main geological features of the Keg River Formation in the regional-scale study area: a) depth to top and b) top structure elevation. The location of the Provost Keg River injection site and the local-scale study area is also shown. Contour interval = 100 metres.

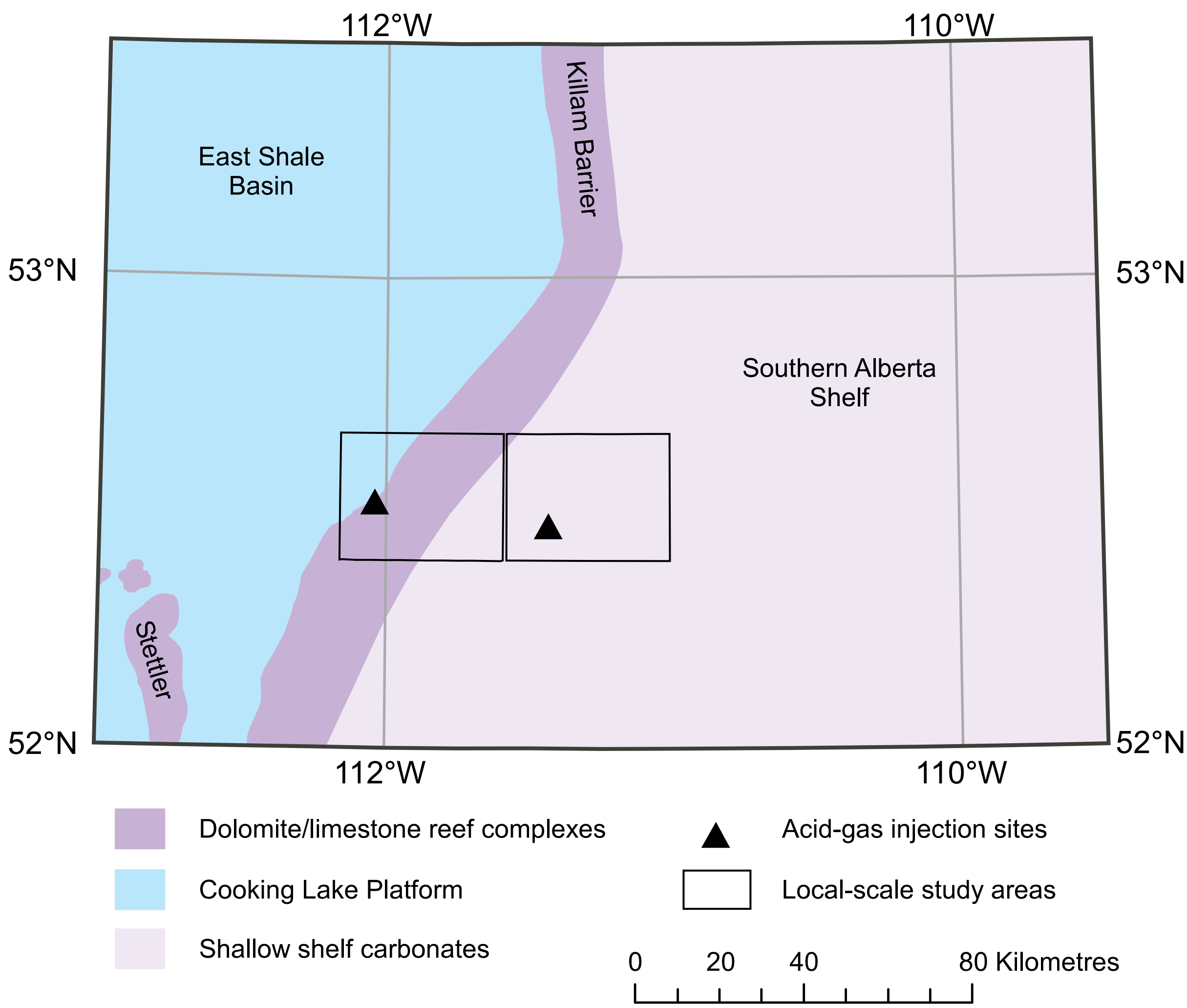


Figure 17. Generalized lithofacies of the Woodbend Group in the regional-scale study area (after Switzer *et al*., 1994). The location of the Galahad Leduc and Provost Leduc injection sites and their respective local-scale study areas is also shown.

The lithology of the Leduc Formation is highly variable as a result of facies variations inherent to shallow-water reef systems (see also Whalen *et al.,* 2000) and of post-sedimentary (diagenetic) processes, such as dolomitization. Most of the reefs in the regional-scale study area are pervasively dolomitized, and the original facies patterns are largely destroyed. Although the reefs are commonly dolomitized, some undolomitized occurrences are known. The reefs may reach thicknesses of up to 250 m. Leduc reef growth within the regional-scale study area preferentially took place along the shelf-platform edge of the underlying Cooking Lake Formation, resulting in a chain of reefs that is commonly known as the Killam Barrier Reef Trend (Figure 13). The depth to the top of the Leduc Formation in the regional-scale study area ranges between more than 1700 m in the southwest to less than 600 m in the northeast (Figure 18a). The top of the Leduc Formation dips southwestward with a slope of about 4.2 m/km, from above 0 m in the northeast to -800 m in the southwest (Figure 18b).

Areas of deeper-water conditions to the west of this reef trend were the site of deposition of basinal limestones and shales of the Duvernay and Ireton formations and have been aptly named the East Shale Basin (Figure 17). In the East Shale Basin, the shales have an average thickness of 150 m, thickening westwards as the underlying Duvernay Formation thins. The Ireton Formation thins to about 3 m on top of the reefal carbonates of the Leduc Formation.

The Woodbend Group conformably overlies the calcareous shales and argillaceous limestones of the Beaverhill Lake Group (Waterways Formation) and is conformably overlain by carbonates of the Winterburn Group (Switzer *et al.,* 1994).

4.1.3 Devonian Wabamun Group

The Wabamun Group in the regional-scale study area consists of dolomitic limestones and calcareous dolomites (Figure 19), with the limestones predominating in the upper part of the formation and dolomites in the middle and lower parts. Appreciable interbedded anhydrite occurs, forming a prominent zone near the base of the formation in some areas. In the southeastern part of the study area, halite may be interbedded with these anhydrites. In the northern and eastern part of the study area, the Wabamun is of variable lithology. Brecciation, secondary anhydrite and calcite veining are common. At the upper contact with the Exshaw Formation, the limestone may be highly pyritic.

The depth to the top of the Wabamun Group in the regional-study area ranges between more than 1600 m in the southwest along the deformation front to less than 800 m in the northeast (Figure 20a) with an average thickness of 200 m in the western part of the area, whereas it thins towards the east where it approaches the sub-Cretaceous unconformity and has been eroded to around 0 m. The top of the Wabamun Group dips southwestward with a slope of 4.6 m/km, from above -100 m in the northeast to less than -700 m in the southwest (Figure 20b).

The Wabamun Group is underlain by siliciclastics and carbonates of the Graminia-Blueridge succession of the Winterburn Group, which reach a thickness of about 30 m in the study area. The injection zone is overlain by several metres of tight shales of the Exshaw Formation and 0 to 120 m of shaly carbonates of the Mississippian Banff Formation. In the northeastern part of the study area, beyond the Mississippian subcrop edge, the Wabamun Group is overlain by sandstones of the Lower Mannville Group that are 10 to 100 m thick.

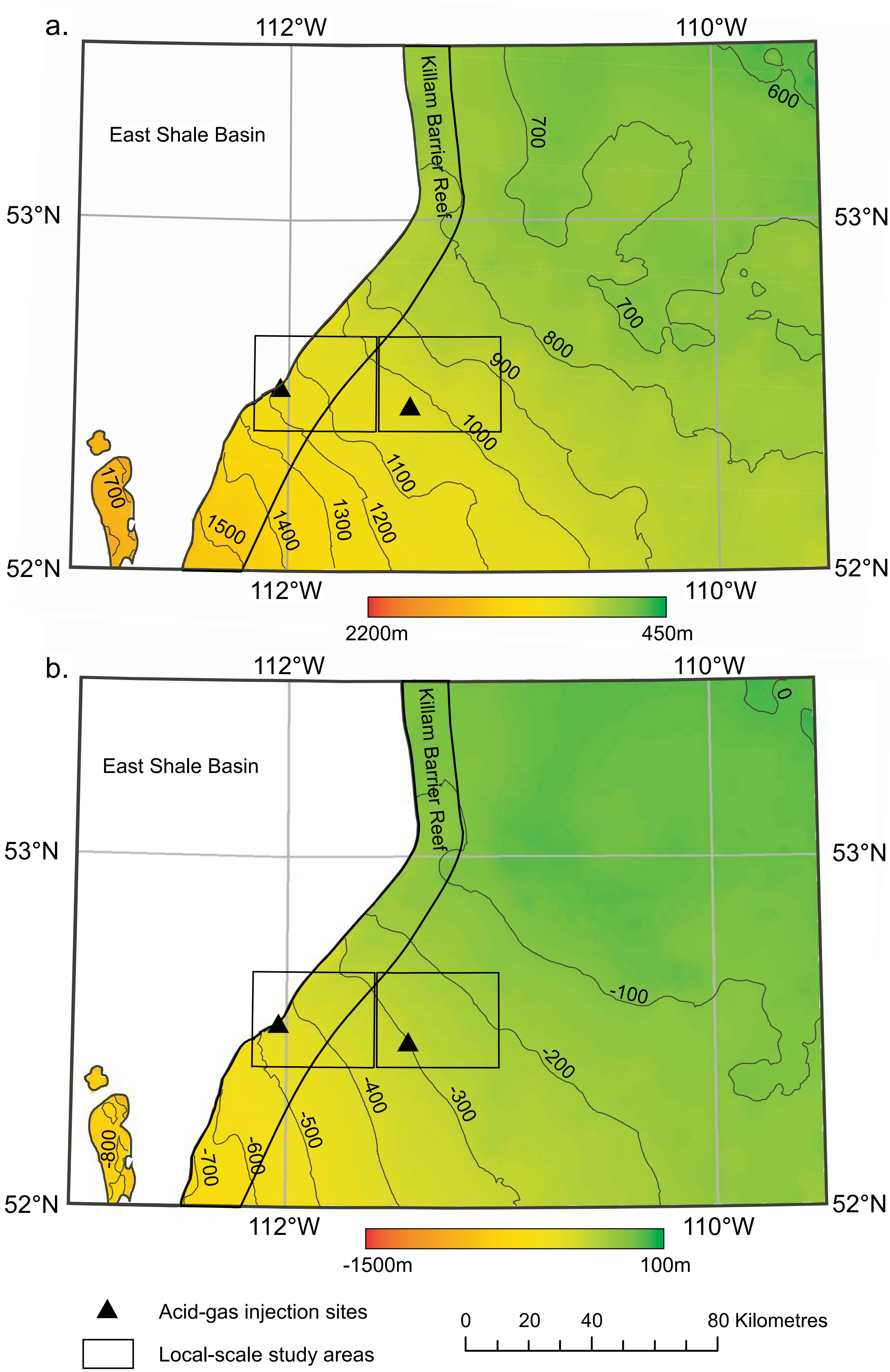


Figure 18. Main geological features of the Leduc-Cooking Lake carbonates in the regional-scale study area: a) depth to top and b) top structure elevation. The location of the Galahad Leduc and Provost Leduc injection sites and their respective local-scale study areas is also shown. Contour interval = 100 metres.

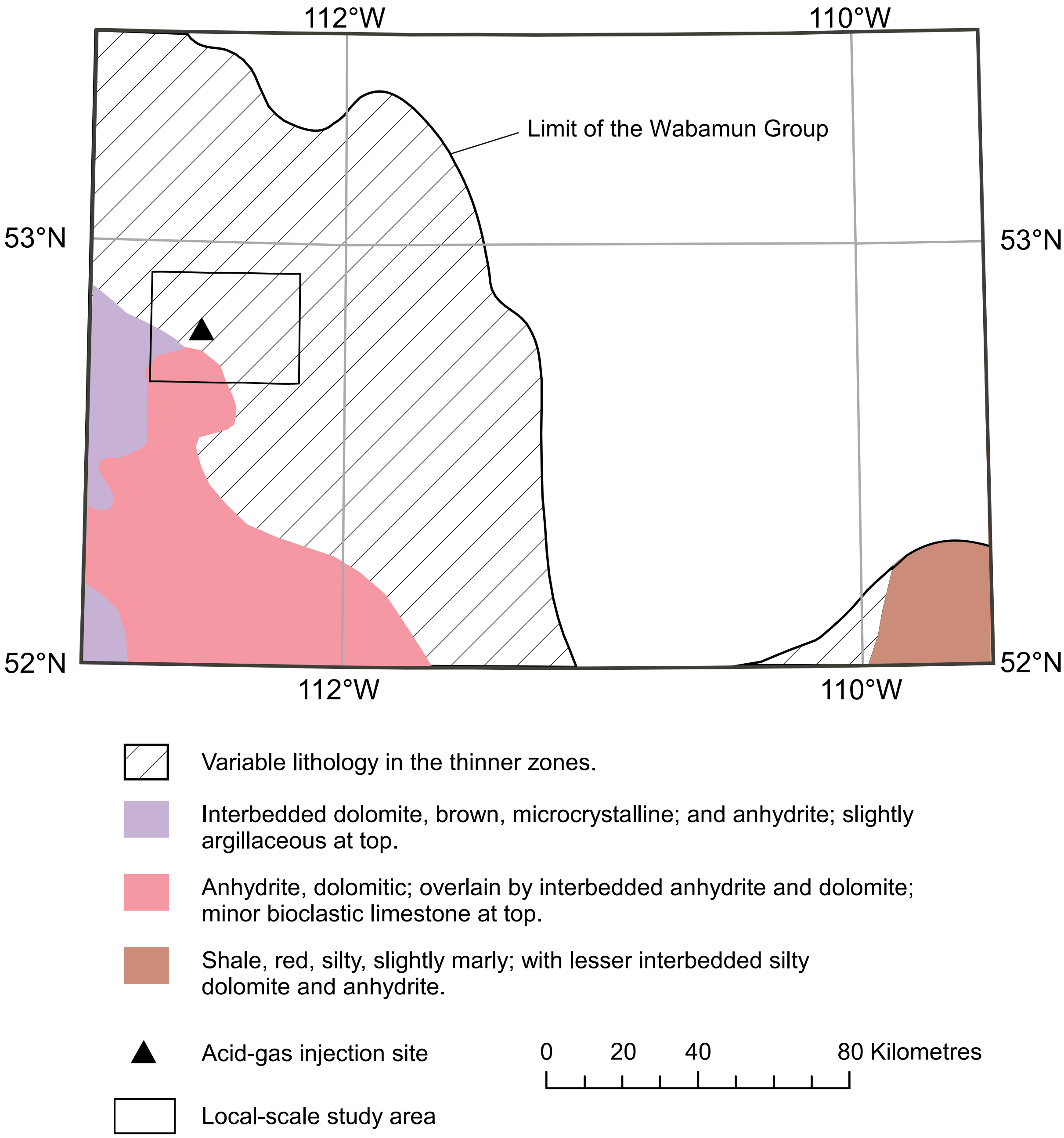


Figure 19. Generalized lithofacies of the Wabamun Group in the regional-scale study area (after Halbertsma, 1994). The location of the Kelsey Wabamun injection site and the local-scale study area is also shown.

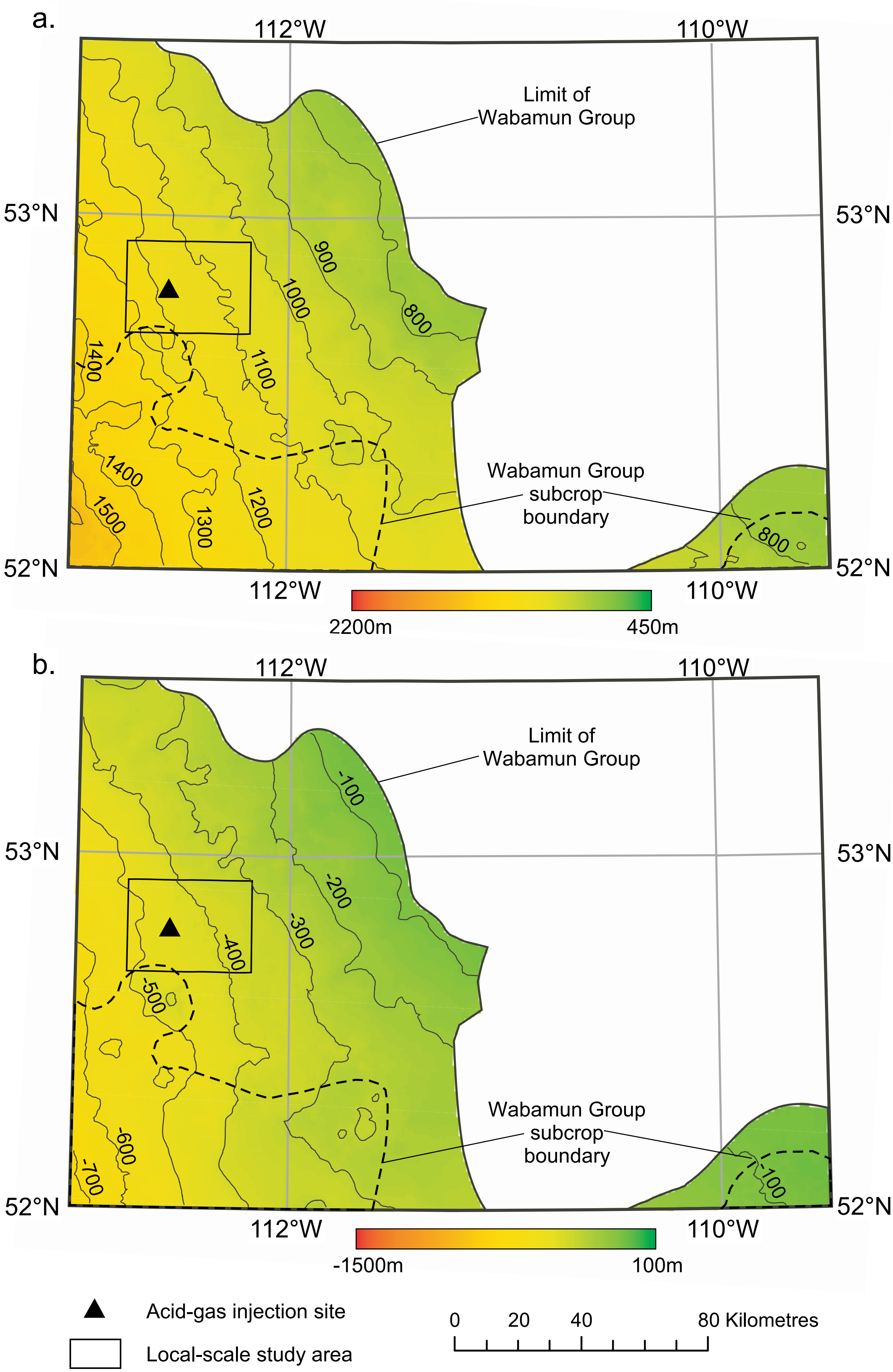


Figure 20. Main geological features of the Wabamun Group in the regional-scale study area: a) depth to top and b) top structure elevation. The location of the Kelsey Wabamun injection site and the local-scale study area is also shown. Contour interval = 100 metres.

4.1.4 Cretaceous Mannville Group

Sandstones of the Cretaceous Mannville Group are the shallowest acid-gas injection target in the Provost area. The Mannville Group was deposited over a broad unconformity surface that truncates strata ranging from lowermost Cretaceous in the foothills to lower Paleozoic at the eastern margin of the basin. In the regional-scale study area the Mannville sandstones are successively underlain from west to east by Mississippian carbonates and shales of the Banff and Exshaw formations, and Upper Devonian carbonates of the Wabamun, Winterburn, and Woodbend groups (Figures 13 and 14). In addition to tectonic factors, differential erosion of dipping Paleozoic carbonates likely influenced the development of relief on the unconformity surface (Hayes *et al.,* 1994).

The Mannville Group is subdivided into a Lower and an Upper Mannville succession (Figure 12). The Ellerslie Member (Basal Quartz) and the Cummings Member injection intervals lie within the Lower Mannville Group. The following description emphasizes their origin and development within the regional-scale study area.

Deposition of the Lower Mannville Group sediments in the regional-scale study area was limited to the Edmonton Valley, which was bordered by the Pembina Highlands to the west of the study area, the Wainwright Highlands to the east and the Kindersley Highlands to the southeast (Figures 8 and 21). Predominantly fluvial sandstones and conglomerates of the Ellerslie Member grade upwards into brackish sandstones, siltstones, shales and limestones of the Ostracod Beds (Cant and Stockmal, 1989). The deposition of the Ostracod Beds was linked to the early stages of transgression of the Clearwater Sea from the north. Brackish bays advanced southward along the Edmonton valley system (Figure 8), but the major highlands still remained emergent. Deltaic and shoreline sandstones of the Glauconitic Sandstone Formation interfinger with the Clearwater equivalent shales and siltstones and incise into the Ellerslie Member, the bottom of the Glauconitic Sandstone formation defining the boundary between the Lower and the Upper Mannville groups. The remainder of Upper Mannville Group strata in the regional-scale study area consists mainly of undifferentiated non-marine to marginal marine sandstone to shale units (Cant and Stockmal, 1989).

The depth to the top of the Ellerslie Member in the regional-study area ranges between more than 1500 m in the southwest to less than 600 m in the northeast (Figure 22a). The average thickness is 40 m in most of the area. The top of the Ellerslie Member dips southwestward from elevations of above 0 m in the northeast to -500 m in the southwest with a slope of approximately 4 m/km in the southwest and 1.5 m/km in the northeast of the regional study area (Figure 22b). The structural dip of the Ostracod Zone (Cummings Member) is in the same order as the Ellerslie Member, since its general thickness in the regional-scale study area is rarely more than 7 m.

The generalized lithofacies distribution of the Lower Mannville Group shows sandstones in the central part of the regional study area (approximately Bellshill Lake channel), which change laterally to interbedded shales and siltstones (Figure 23). In contrast, the lithofacies distribution in the Upper Mannville is dominated by shales and siltstones (Figure 24). The Mannville Group is unconformably overlain by the thick, shale-dominated Late Cretaceous Colorado Group.

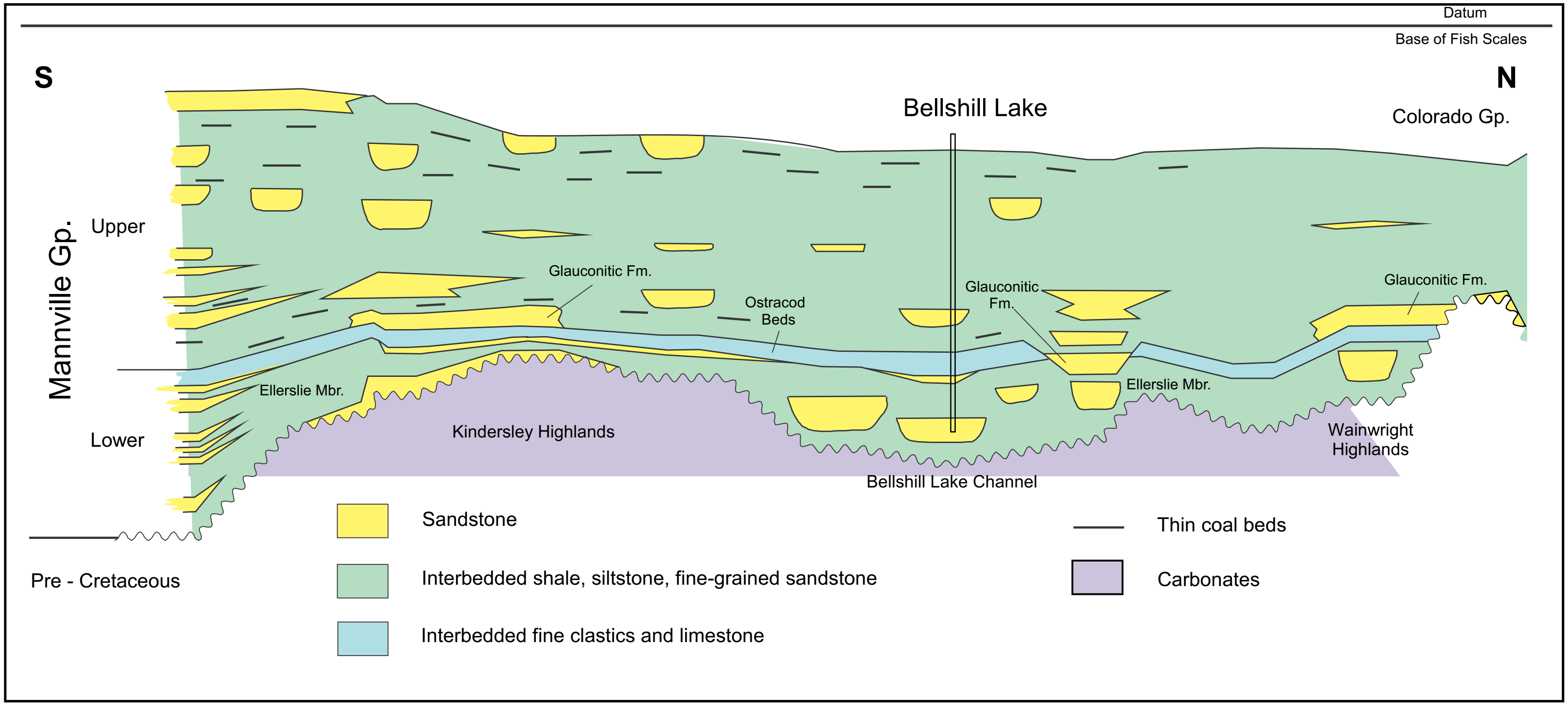


Figure 21. Schematic cross-section through the Bellshill Lake Channel showing the distribution of channel sands versus surrounding shales. Acid gas injection takes place into the channel sands of the Ellerslie/Basal Quartz Member in the Bellshill Channel, which are surrounded and sealed by shales and siltstones (modified after Hayes *et al.*, 1994).

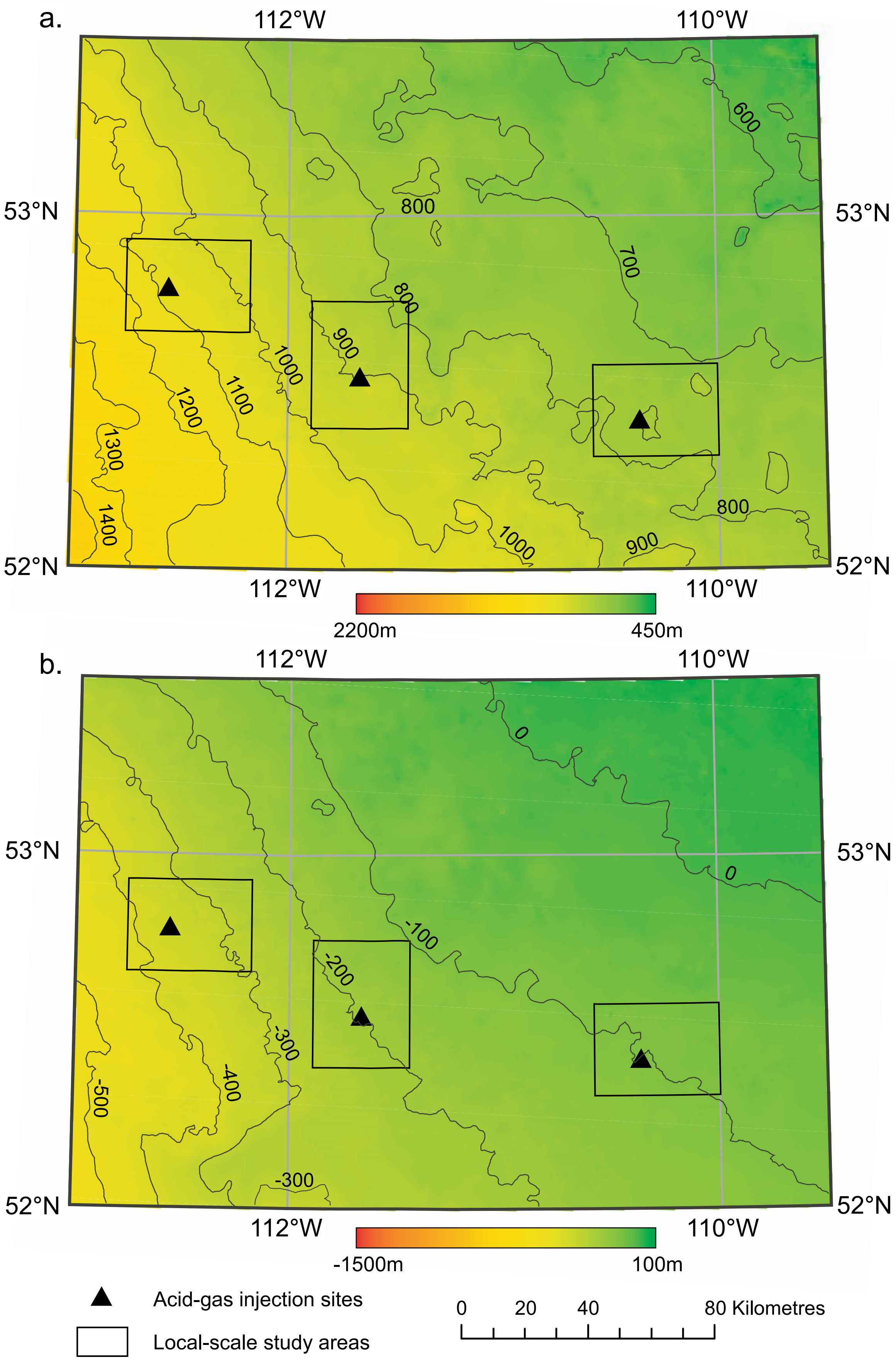


Figure 22. Main geological features of the Ellerslie/Basal Quartz Member in the regional-scale study area: a) depth to top and b) top structure elevation. The location of the Kelsey Wabamun, Bellshill Lake Blairmore and Hansman Lake Cummings injection sites and their respective local-scale study areas is also shown. Contour interval = 100 metres.

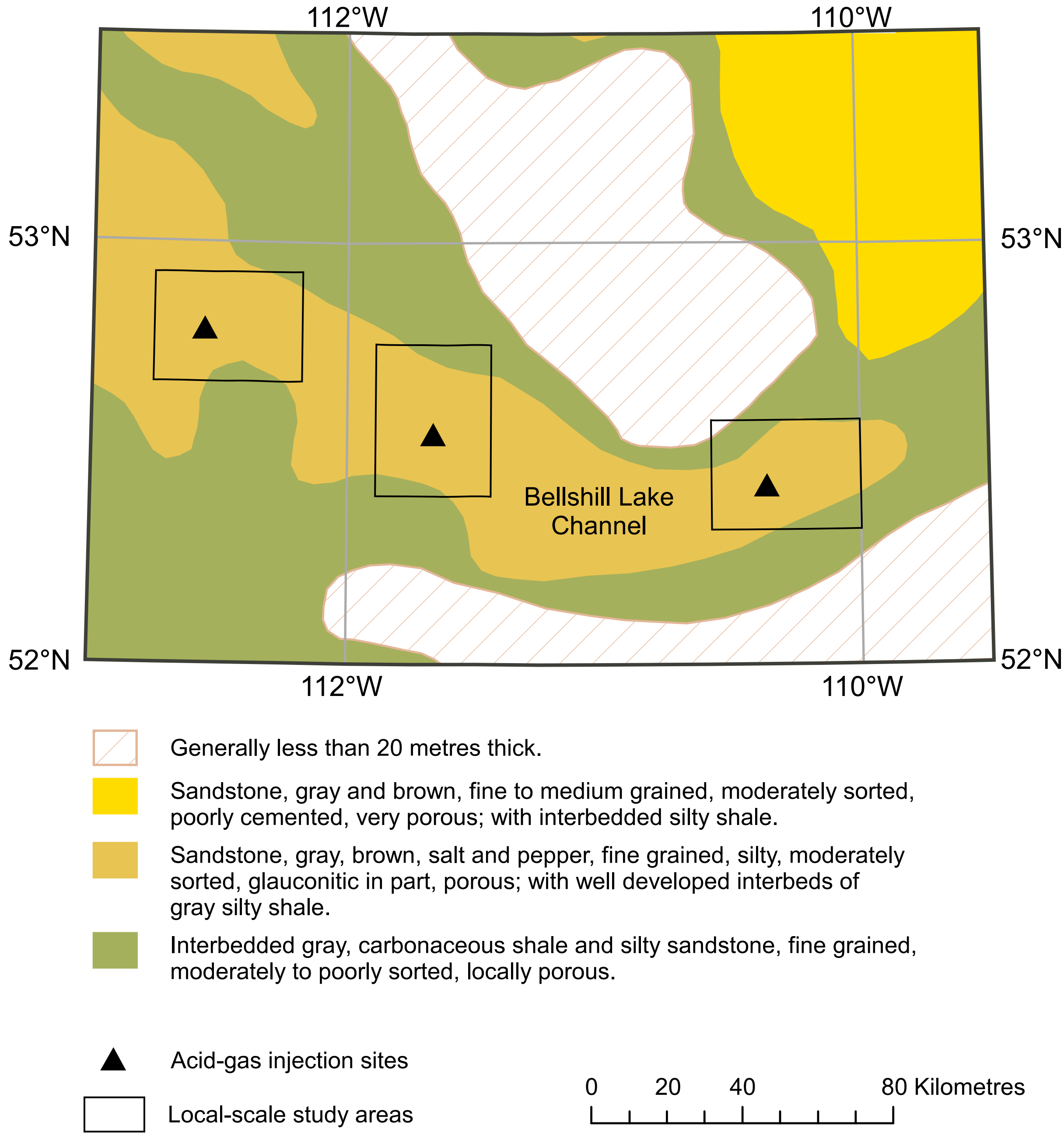


Figure 23. Facies distribution and lithology of the Lower Mannville Group strata in the regional-scale study area (after Hayes *et al.*, 1994). The location of the Kelsey Wabamun, Bellshill Lake Blairmore and Hansman Lake Cummings injection sites and their respective local-scale study areas is also shown.

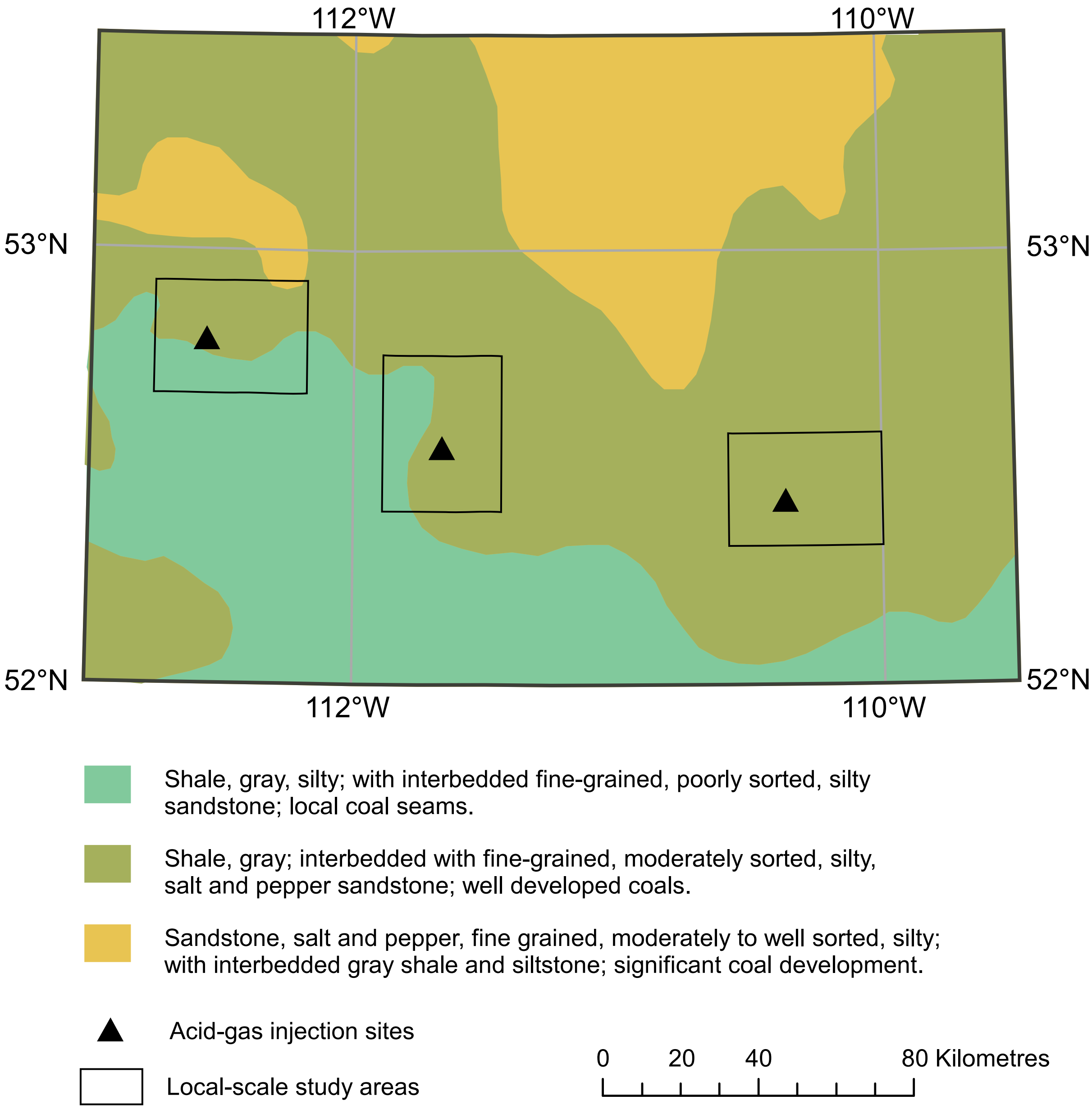


Figure 24. Facies distribution and lithology of the Upper Mannville Group strata in the regional-scale study area (after Hayes *et al*., 1994). The location of the Kelsey Wabamun, Bellshill Lake Blairmore and Hansman Lake Cummings injection sites and their respective local-scale study areas is also shown.

4.2 Hydrogeology of the Elk Point to Lower Mannville Groups

The Devonian Elk Point, Woodbend, and Wabamun groups, as well as the Cretaceous Lower Mannville Group are the focus of the regional hydrogeological assessment because these stratigraphic units contain the targets for the five acid-gas injection operations in the Provost area. Also, a short discussion is included on the hydrogeology of the intervening Devonian Beaverhill Lake and Winterburn groups, because they lie above the Woodbend Group and successively subcrop underneath the Lower Mannville Group along the sub-Cretaceous unconformity (Figures 12 and 14).

4.2.1 Hydrostratigraphy

The Elk Point Group in the regional-scale study area is underlain by the Cambro-Ordovician aquifer-aquitard system (Bachu, 1999) and can be subdivided into three hydrostratigraphic units: a) the Lower Elk Point aquitard, mainly consisting of evaporites, b) the Keg River (Winnipegosis) carbonate aquifer, and c) the Prairie-Watt Mountain aquitard, consisting of shales, anhydrite and salt (Figure 12). The overlying shaly carbonates of the Waterways Formation (Beaverhill Lake Group) generally form an aquitard, with the exception of discontinuous limestones (Calmut, Moberly and Mildred members). The platform carbonates (Cooking Lake Formation) and associated reef complexes (Leduc Formation) of the Woodbend Group that overlie the Waterways Formation form a regional aquifer (Figure 14). These carbonates are encased in and capped by the shales of the Duvernay and Ireton formations, which generally form a thick aquitard at the top of the Woodbend Group west of the Killam Barrier Reef, except where local Leduc reefs are present (e.g., Stettler reef). In the east of the regional-scale study area (i.e., Southern Alberta Shelf), the shales of the Ireton Formation are relatively thin and subcrop beneath the Cretaceous Lower Mannville Group. In these cases, direct hydraulic communication is possible between Leduc reefs and the Nisku Formation in the overlying Winterburn Group, and between the carbonate Leduc-Cooking Lake aquifer and the Lower Mannville sandstone aquifer, respectively. Hydraulic communication between Leduc reefs and the Nisku Formation has been documented in the Bashaw area (Rostron and Toth, 1997) and in the Cooking Lake area (Bachu and Underschultz, 1995) to the west and to the north of the study area, respectively.

Other intervening regional-scale carbonate aquifers that are in contact with the Lower Mannville aquifer along the unconformity are, from west to east and with increasing stratigraphic age, the Mississippian, Wabamun, and Winterburn aquifers (Figures 12 and 14). The Wabamun Group has aquifer characteristics where it consists of carbonates (northwest and central parts of the study area) and is an aquitard in the southwest and southeast where it consists of anhydrite and calcareous shales, respectively. In the study area, Mississippian strata is restricted to thin carbonates of the Mississippian Banff Formation, which are in contact with and, for the purpose of this study, will be considered as part of the Lower Mannville aquifer. The sandstones of the Lower Mannville aquifer are restricted largely to the west-east trending arm of the Edmonton Valley, which takes up the central part of the regional study area (Figure 23). These sandstones are encased in and overlain by Lower and Upper Mannville shales and siltstones, which form the Clearwater-Upper Mannville aquitard (Figure 14). Major sandstone bodies exist in the Upper Mannville Group generally in the northeastern half of the study area, while the remainder of the strata, consisting of siltstones and shales (Figure 24), have aquitard characteristics. The heterogeneous distribution of sandstones versus siltstones and shales throughout the Mannville Group makes it difficult to delineate aquifers and to identify areas of hydraulic interconnection or lack thereof on a regional scale. A "deep basin" type, dominantly gas-saturated region is present in the downdip portion of the Lower Mannville Group in the southwest corner of the study area.

The Mannville Group is overlain by the thick, basin-scale Colorado aquitard system (Bachu, 1999).

4.2.2 Hydrogeological Observations

Hydrochemical analyses of formation waters and drillstem tests were used to interpret the flow of formation waters in the various aquifers in the regional study area. The data used in this study (Table 1) are in the public domain and are available from the Alberta Energy and Utilities Board (EUB). The data were culled for erroneous analyses and tests, including production influence, and processed according to the methods presented by Hitchon and Brulotte (1994), Hitchon (1996) and Michael and Bachu (2002). Sparse data distribution in the Cambrian to Middle Devonian Beaverhill Lake aquifers limits the regional characterization of these hydrogeological units to a general representation in Piper plots (chemistry) and pressure-elevation plots (DST data). In addition, maps showing the distribution of salinity and hydraulic heads were used in the regional hydrogeological characterization of each of the Upper Devonian and Mannville Group aquifers.

Table 1. Ranges of salinity (TDS) and hydraulic-head values in the various aquifers in the Provost area. Also shown are the number of chemical analyses of formation water and drillstem test (DST) data that were used in the regional assessment of formation water flow, and estimates of average formation water density.

	Formation Water Chemistry				Hydraulic Head		
	TDS range	Avg TDS	#	Avg density	Range	Avg	#
Cambrian - Keg River	226 - 327 g/l	286 g/l	10	1192 kg/m^3	517 - 602 m	548 m	5
Beaverhill Lake	179 - 356 g/l	287 g/l	5	1196 kg/m^3	462 - 649 m	576 m	16
Woodbend	33 - 220 g/l	111 g/l	105	1072 kg/m^3	383 - 616 m	426 m	92
Winterburn	18 - 211 g/l	98 g/l	167	1064 kg/m^3	395 - 490 m	390 m	123
Wabamun	65 - 121 g/l	84 g/l	47	1054 kg/m^3	346 - 573 m	400 m	33
Lower Mannville	13 - 138 g/l	75 g/l	586	1052 kg/m^3	337 - 570 m	421 m	345
Upper Mannville	17- 99 g/l	68 g/l	600	1047kg/m^3	403 - 580 m	491 m	133

Chemistry of Formation Waters

Generally, formation waters in the Provost area are of a Na-Cl type, with the exception of some Upper Devonian Na-Ca-Cl waters from areas that are not in direct hydraulic communication with the overlying Lower Mannville aquifer (Figure 25). On average, the salinity of formation waters increases with depth and stratigraphic age from 68 g/l in the Upper Mannville aquifer to 287 g/l in the Cambrian to Middle Devonian aquifers (Table 1). Noticeably, the average salinity in the vertically isolated Cambrian to Middle Devonian aquifers is more than double the salinity in the Upper Devonian and Mannville aquifers. Differences in distribution patterns of salinity in the latter aquifers are associated with the respective subcrop areas of the Upper Devonian aquifers where they come in contact and mix with Lower Mannville formation waters (see also Anfort *et al.,* 2001).

Formation waters in aquifers that underlie the Keg River aquifer have salinity values between 226 g/l in the Cambrian and approximately 300 g/l in the Ordovician (Table 1). Due to the sparse data, it is impossible to establish a regional distribution pattern of salinity in these aquifers. Likewise, only three analyses of formation water chemistry exist for the Keg River aquifer in the Provost area, salinity values ranging between approximately 247 and 327 g/l. In the overlying

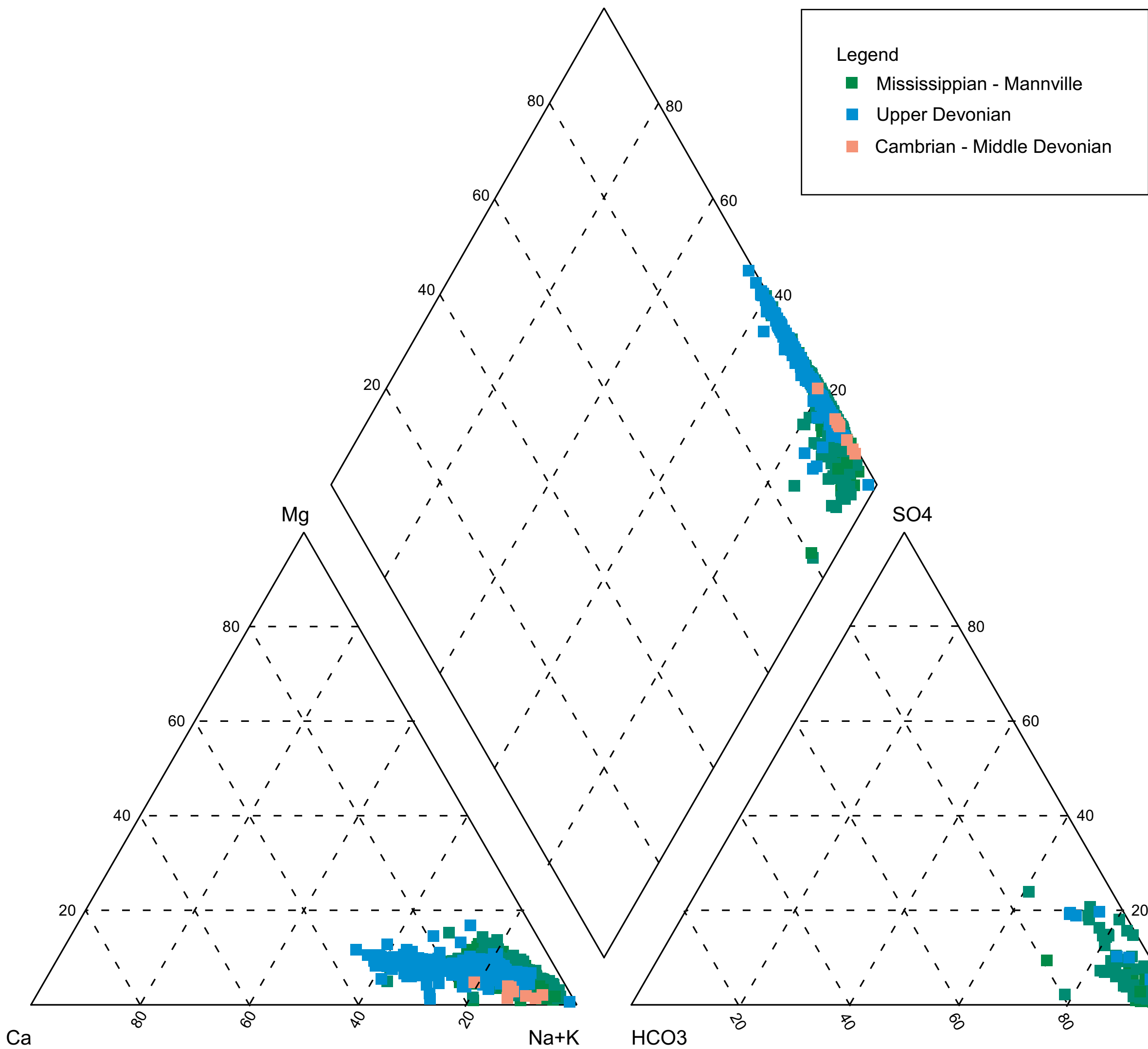


Figure 25. Piper plot of Cambrian to Lower Cretaceous (Mannville Group) formation waters in the regional-scale study area.

Beaverhill Lake aquifer, salinity values measured at four locations range between 179 and 358 g/l. Generally, the range of salinity in the Cambrian to Middle Devonian aquifers is very similar, and the salinity appears to increase from less than 200 g/l in the northwest to more than 300 g/l in the east and south of the Provost area (Figure 26).

In the overlying Upper Devonian Leduc-Cooking Lake aquifer, salinity values are significantly lower, decreasing from 220 g/l in the southwest to less than 75 g/l in the north- and southeast of the Provost area and reaching a minimum of less than 40 g/l in the southeast (Figure 27). Similarly, in the Winterburn aquifer salinity decreases from 210 g/l in the southwest to less than 30 g/l in the southeast (Figure 28a). Formation water salinity in the overlying Wabamun aquifer decreases in the same east southeastward direction as in the Leduc-Cooking Lake and Winterburn aquifers. The maximum salinity value is only 120 g/l, but no formation water analyses exist in the southeast corner of the study area where the Wabamun has aquitard characteristics (Figure 28b).

The salinity of formation water in the Lower Mannville aquifer ranges from less than 20 g/l along the southern boundary of the regional study area to more than 100 g/l in the west (Figure 29a). A sharp increase in salinity from 60 to 80 g/l can be observed along an eastward trending line in the lower third of the study area. In the Upper Mannville aquifer, the salinity distribution is very similar to that in the Lower Mannville aquifer. However, salinity values are slightly lower on average in the Upper Mannville and there is no sharp salinity increase to be observed (Figure 29b).

The formation water density, which is mainly dependent on salinity (Table 1), was calculated using regression expressions from measured data in the Alberta Basin and scaling to in-situ conditions after Rowe and Chou (1970) (Adams and Bachu, 2002). Accordingly, formation water density increases from 1047 kg/m^3 in the Upper Mannville aquifer to 1196 kg/m^3 in the Middle Devonian and Cambrian aquifers.

Flow of Formation Waters

The analysis of the flow of formation waters is based on pressure data from drillstem tests in the Cambrian to Mannville groups. Contour maps showing the distribution of hydraulic-head values could only be created for the Beaverhill Lake, the Upper Devonian and Mannville aquifers because of the poor data coverage in the Cambrian to Elk Point Group succession. Still, general conclusions with respect to the pressure conditions in the Cambrian, Ordovician, and Keg River aquifers, and an assessment of vertical hydraulic communication with overlying aquifers could be made using pressure-elevation and pressure-depth relationships.

For the Beaverhill Lake to Mannville groups, hydraulic heads were calculated with a reference density of 1060 kg/m^3 in order to minimize the errors in representing and interpreting the flow of variable density water in the vicinity of the acid-gas injection sites (Bachu and Michael, 2002). The reference density corresponds to the average brine density at conditions characteristic for the Woodbend-Mannville succession in the regional study area (Table 1). The formation water density in the Beaverhill Lake aquifer is significantly higher. Still, the same reference density of 1060 kg/m^3 was used in calculating equivalent hydraulic-head values, so that the respective contour maps in the various aquifers could be compared to each other. Hydraulic heads were calculated according to:

$$H = \frac{p}{\rho_o g} + z \qquad (1)$$

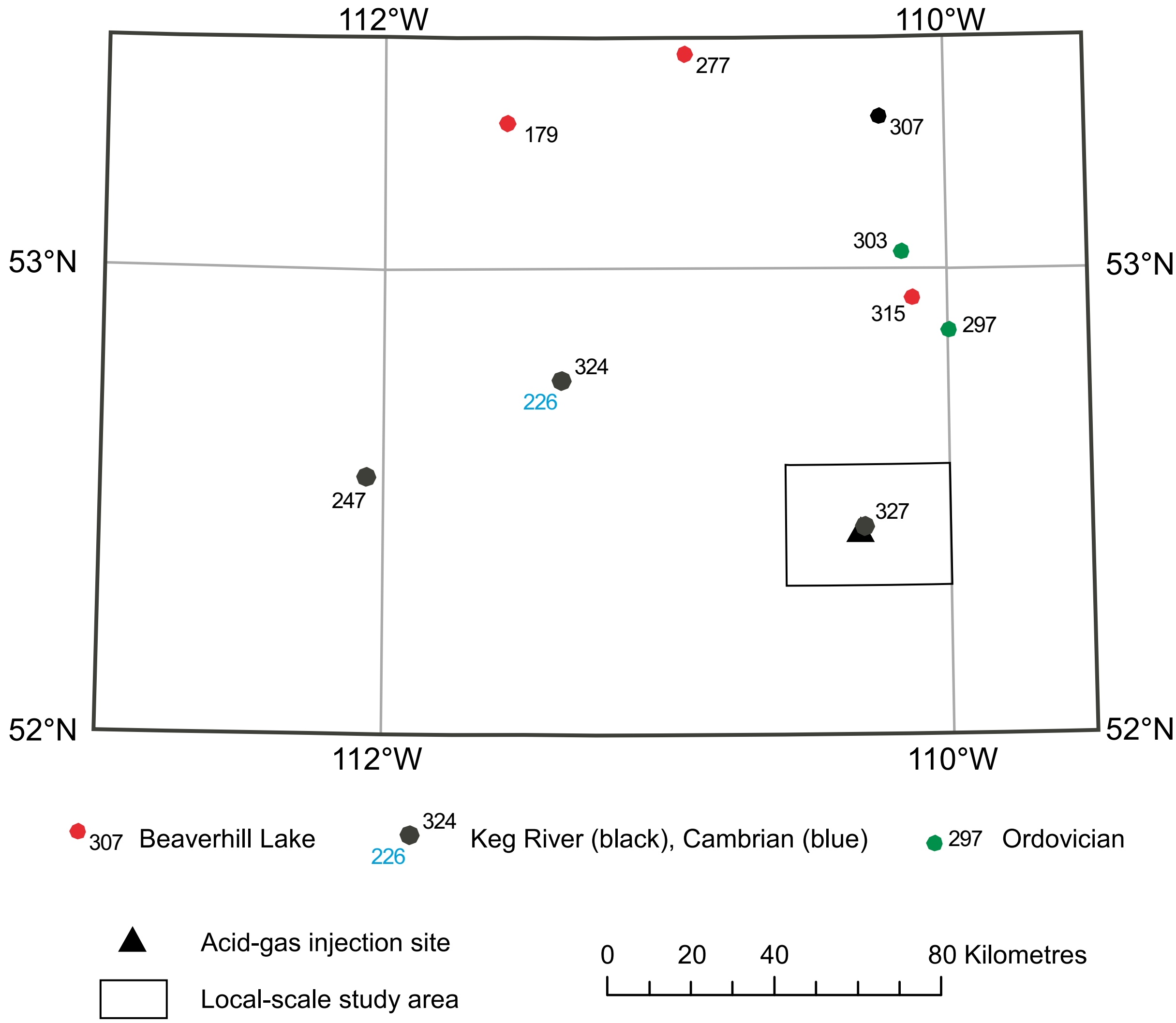


Figure 26. Individual salinity values of formation waters (g/l) in the succession from the Cambrian to the Elk Point Group. The location of the Provost Keg River injection site and the local-scale study area is also shown.

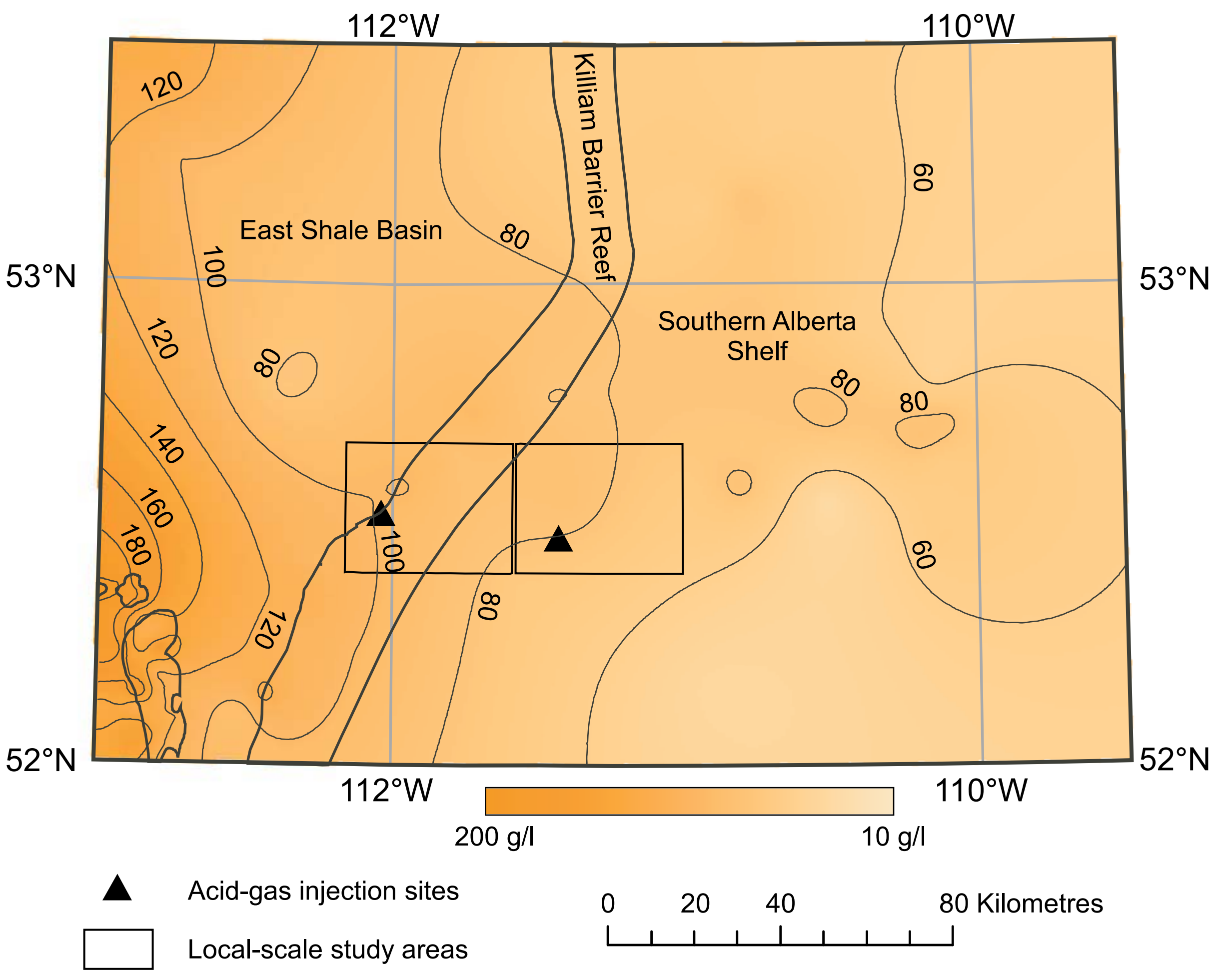


Figure 27. Regional distribution of salinity in the Leduc-Cooking Lake aquifer. The location of the Galahad Leduc and Provost Leduc injection sites and their respective local-scale study areas is also shown. Contour interval = 20 g/l.

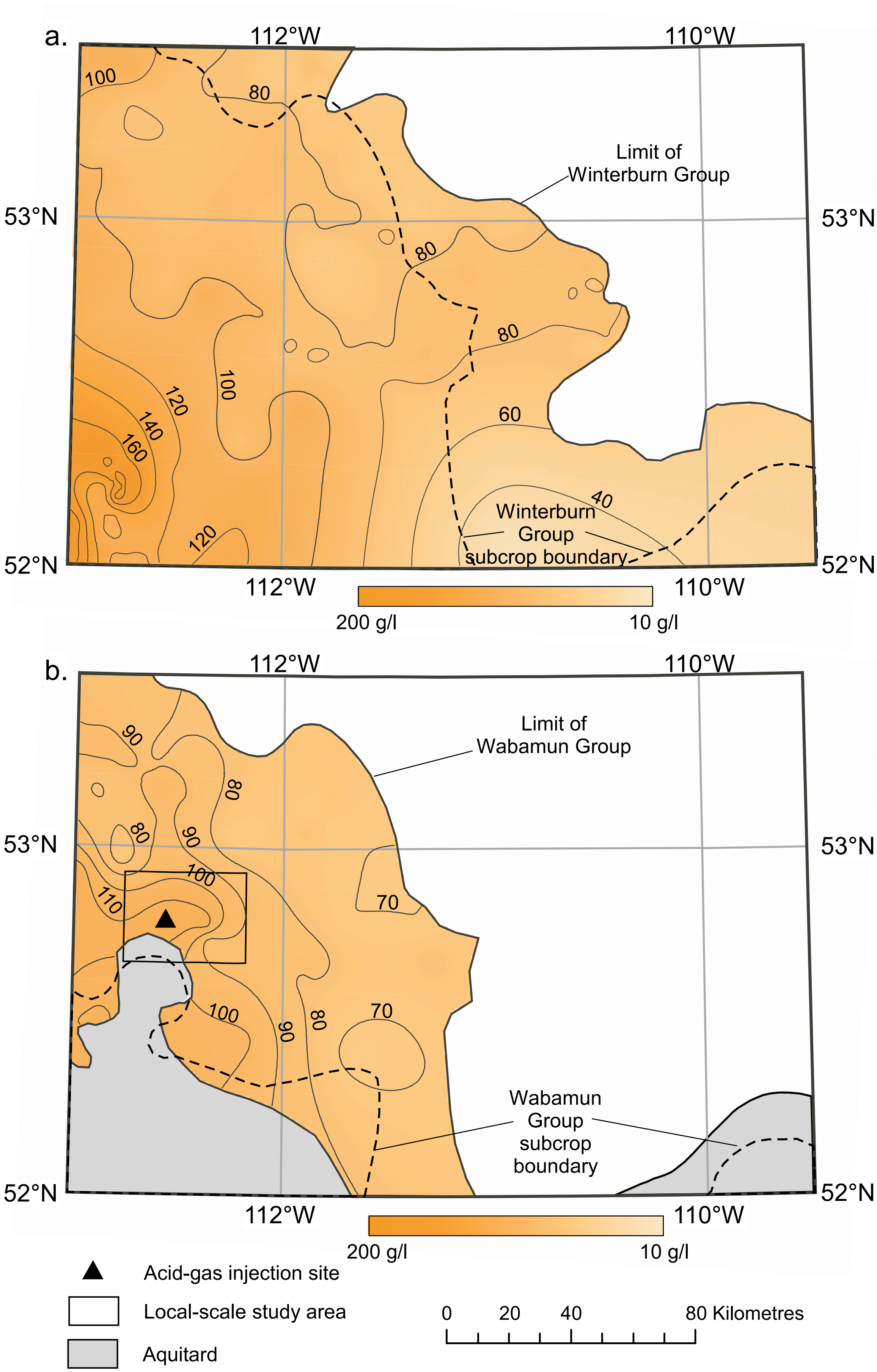


Figure 28. Regional distribution of salinity in the: a) Winterburn and b) Wabamun aquifers. The location of the Kelsey Wabamun injection site and the local-scale study area is also shown in Figure 28b. Contour intervals are 20 g/l and 10 g/l, respectively.

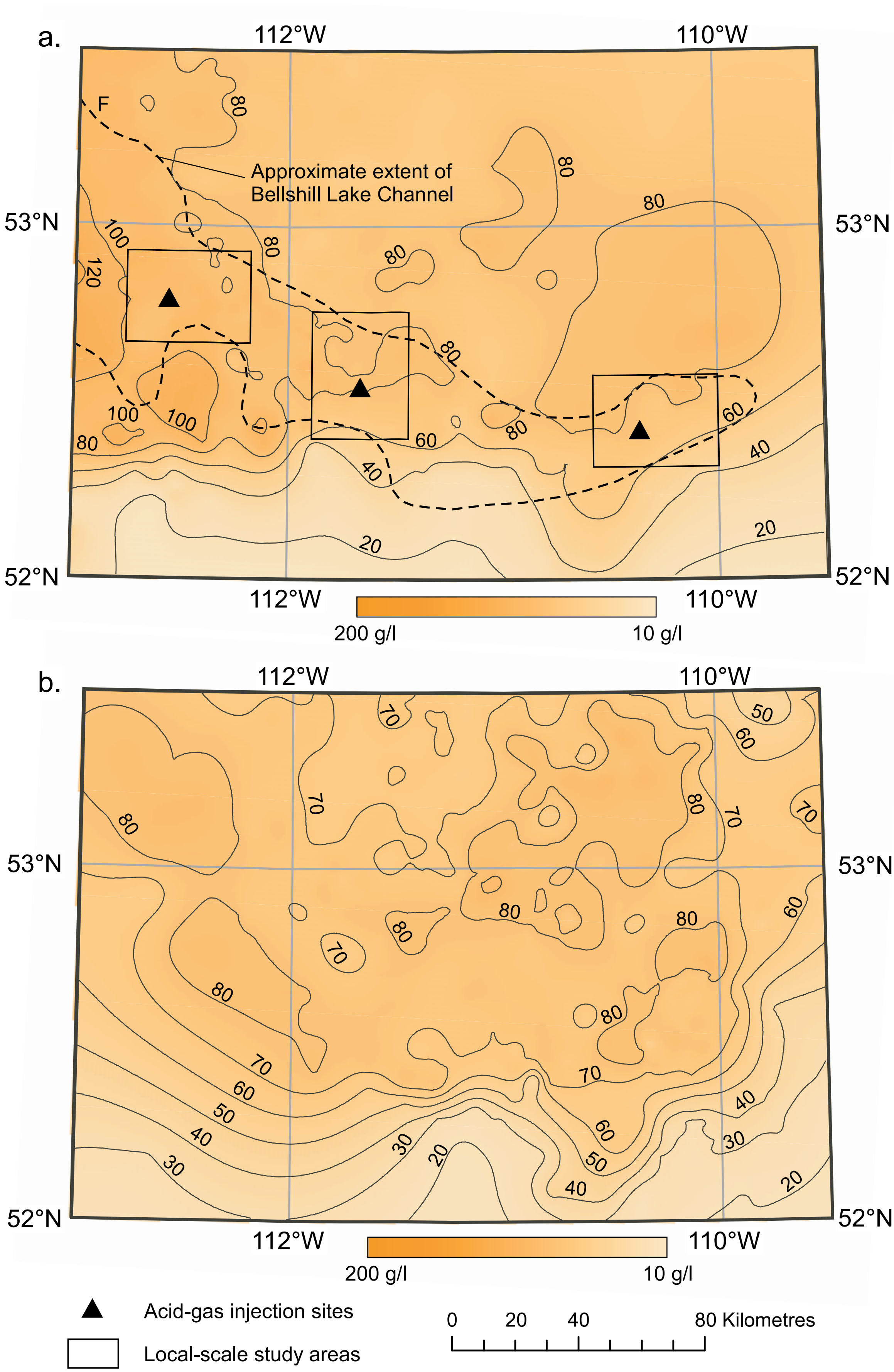


Figure 29. Regional distribution of salinity in the: a) Lower Mannville and b) Upper Mannville aquifers. The location of the Kelsey Wabamun, Bellshill Lake Blairmore and Hansman Lake Cummings injection sites and their respective local-scale study areas is also shown in Figure 29a. Contour intervals are 20 g/l and 10 g/l, respectively.

where z (m) is the elevation of the pressure recorder, p (Pa) is pressure, ρ_o (kg/m^3) is the reference density and g is the gravitational constant (9.81 m/s^2).

The pressure distribution versus depth in the Cambrian to Mannville Group succession indicates that all aquifers are hydrostatically to sub-hydrostatically pressured (Figure 30a). The pressure data from the various aquifers are distributed into three clusters. Most of the pressure data from the Cambrian to Beaverhill Lake aquifers plot near or slightly below the freshwater hydrostatic gradient in Cluster I. The majority of the data, mainly from the Woodbend to Mannville aquifers (Cluster II), plot along a steeper pressure-depth gradient, indicating that these aquifers have developed more advanced sub-hydrostatic conditions than the deeper aquifers. These different pressure conditions suggest that the intervening aquitards retard pressure equilibration between the Cambrian to Middle Devonian and Upper Devonian to Mannville aquifers. A small number of data from the southwest corner of the Lower Mannville aquifer (Cluster III) plot along a static gas pressure gradient, indicating the existence of a deep-basin style gas accumulation in the downdip part of the Lower Mannville Group. Plotting the pressure distribution versus elevation relative to sea level shows that data from the Upper and Lower Mannville aquifers are shifted towards higher pressures compared to data from the Upper Devonian aquifers, indicating a downward gradient of formation water flow (Figure 30b). Data in the Cambrian to Middle Devonian aquifers are shifted also towards higher pressures, hence indicating the potential for upward flow from the Beaverhill Lake aquifer into the Cooking Lake aquifer. The pressure-elevation distribution of Mannville and Upper Devonian data is continuous and partly overlaps, indicating relatively good vertical hydraulic communication between the various aquifers. In contrast, the offset of data in the Cambrian to Middle Devonian aquifers from the pressure data in the Upper Devonian aquifers suggest that the intervening Waterways aquitard is an effective barrier to vertical flow.

Formation water flow inferred from hydraulic-head distributions in the Leduc-Cooking Lake aquifer is convergent, from areas with hydraulic heads > 500 m in the west and > 450 in the east to an area with hydraulic-head values < 400 m in the centre of the Killam Barrier (Figure 31). The closed 400 m contour line suggests a sink in the Leduc-Cooking Lake aquifer in this area and vertical cross-formational flow into the overlying Winterburn aquifer. The steep hydraulic gradient sub-parallel to the Killam Barrier suggests a restriction to formation water flow, which is probably due to a decrease in aquifer transmissivity caused by the thinning of the Cooking Lake aquifer from over 200 m at the Bashaw reef complex just west of the study area to 50 m and less in the area of the East Shale Basin.

The hydraulic-head distribution in the overlying Winterburn aquifer suggests a general northwestward flow direction (Figure 32a). Maximum hydraulic-head values above 450 m are observed in the subcrop area of the Winterburn aquifer below the Lower Mannville aquifer in the central and southeastern parts of the study area.

Flow in the overlying Wabamun aquifer is also towards the northwest (Figure 32b), hydraulic head values being in the same range as in the underlying Winterburn aquifer, which indicates that these two aquifers are in hydraulic communication, particularly along their subcrop areas, as generally shown at the basin scale by various other studies (Bachu, 1999, and references therein; Anfort *et al.,* 2001). Only in the southwest are hydraulic head values > 575 m significantly higher than values observed in the underlying Devonian aquifers in the study area.

The hydraulic head distribution in the Lower Mannville aquifer (Figure 33a) mirrors the hydraulic head distributions in the respective subcropping aquifers along the pre-Cretaceous unconformity, where the Upper Devonian aquifers are in hydraulic communication with the

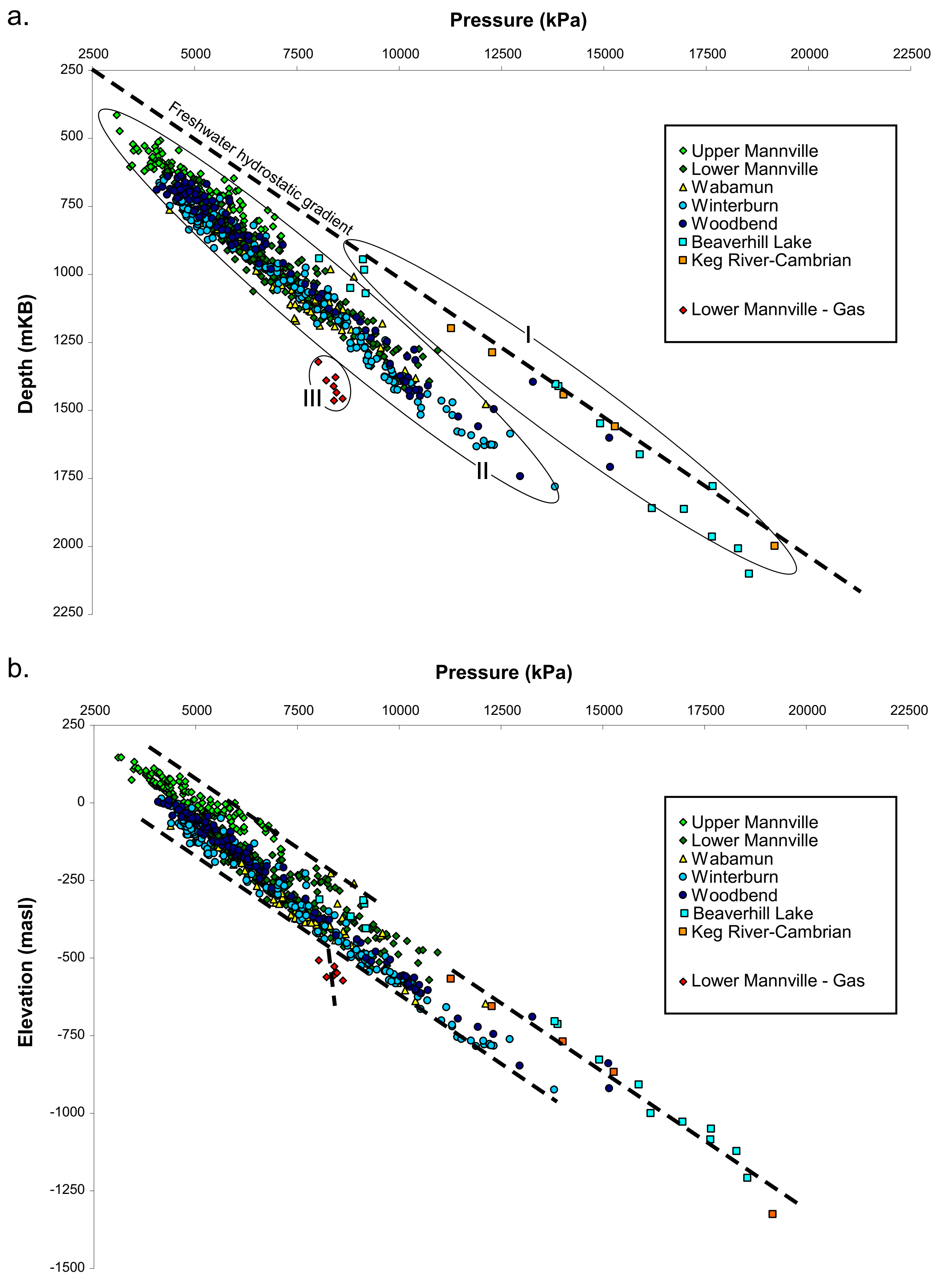


Figure 30. Distribution of pressure versus: a) depth and b) elevation in the Cambrian to Upper Mannville Group succession in the Provost area.

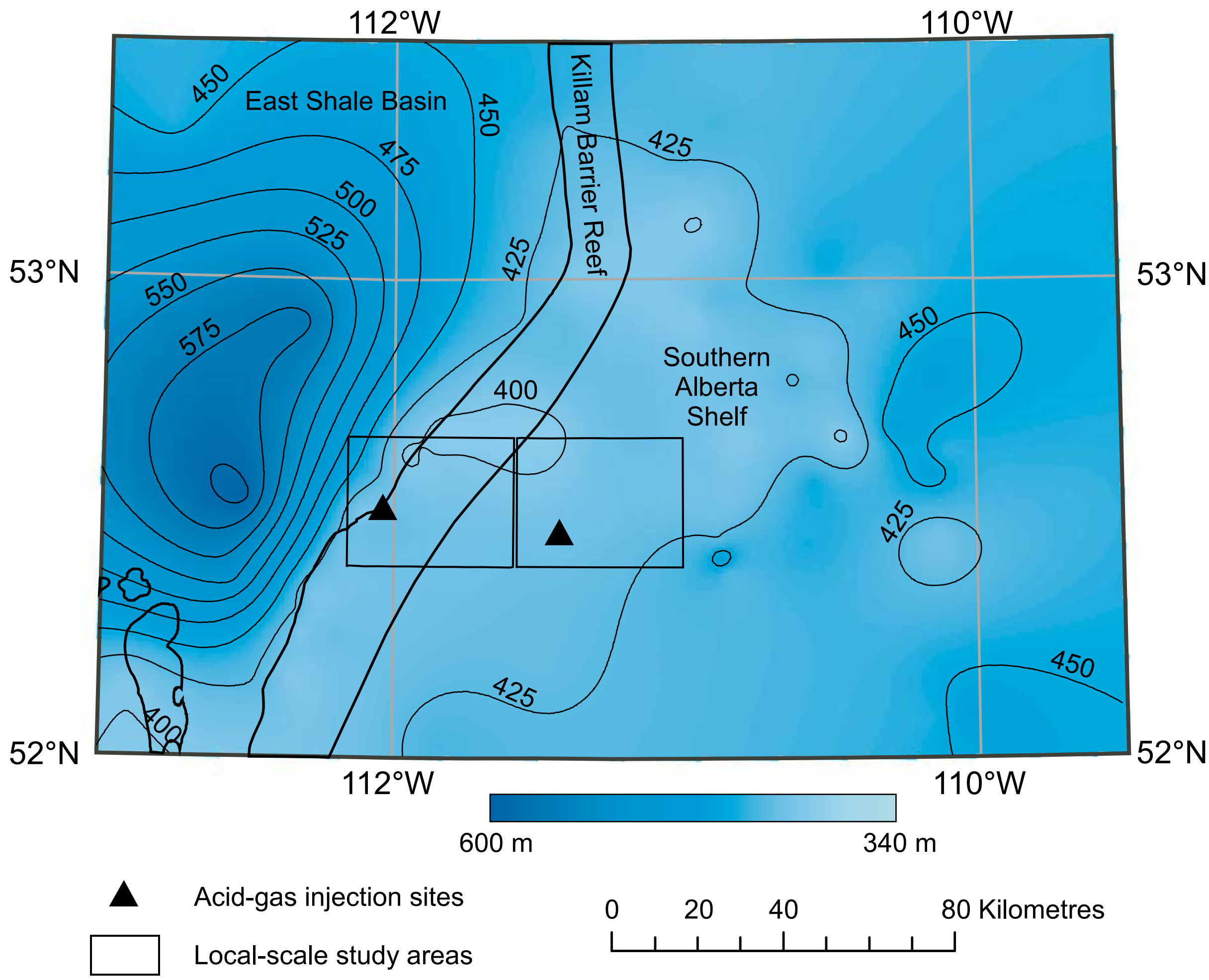


Figure 31. Regional distribution of hydraulic heads in the Leduc-Cooking Lake aquifer. The location of the Galahad Leduc and Provost Leduc injection sites and their respective local-scale study areas is also shown. Contour interval = 25 metres.

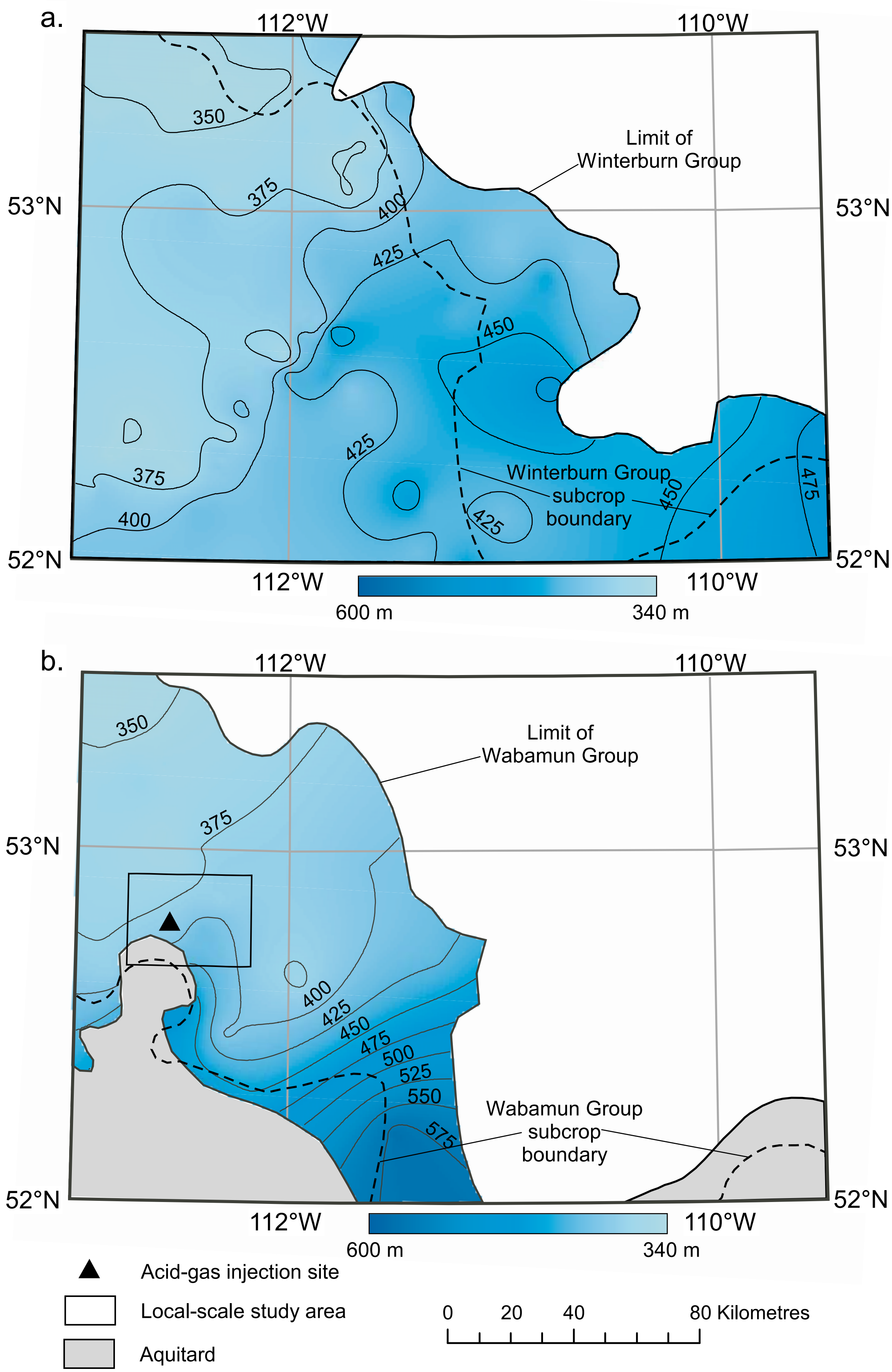


Figure 32. Regional distribution of hydraulic heads in the: a) Winterburn and b) Wabamun aquifers. The location of the Kelsey Wabamun injection site and the local-scale study area is also shown in Figure 32b. Contour interval = 25 metres.

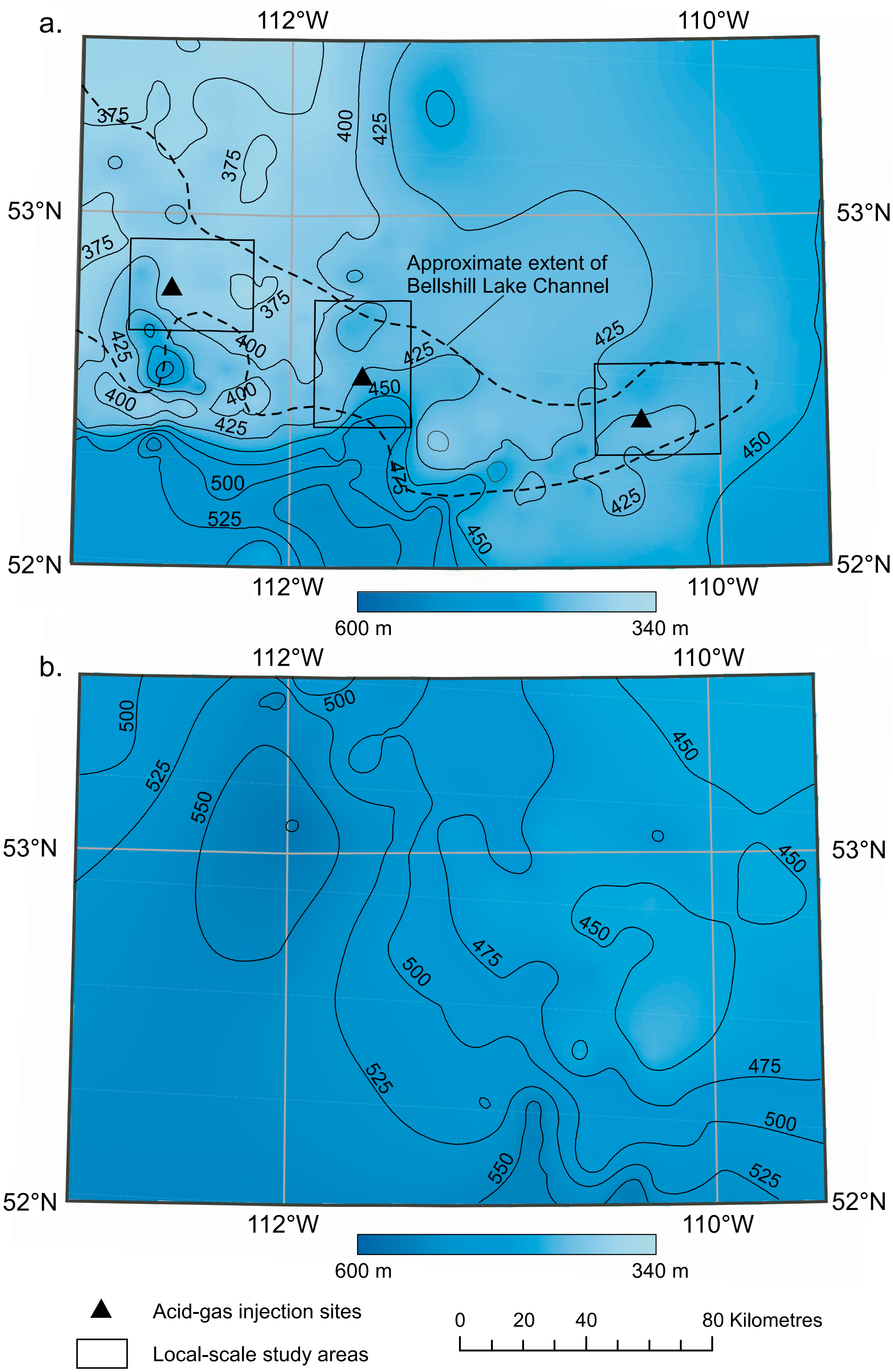


Figure 33. Regional distribution of hydraulic heads in the: a) Lower Mannville and b) Upper Mannville aquifers. The location of the Kelsey Wabamun, Bellshill Lake Blairmore and Hansman Lake Cummings injection sites and their respective local-scale study areas is also shown in Figure 33a. Contour interval = 25 metres.

Lower Mannville aquifer. The flow of formation waters is towards the northwest, partly following the direction of the sand-filled, higher-permeable Bellshill Lake Channel. Hydraulic-head values less than 300 m in the southwest corner of the study area are probably due to a deep-basin type gas accumulation that is located down dip of the water leg in a low-permeability facies of the Lower Mannville Group.

The hydraulic-head distribution in the Upper Mannville aquifer (Figure 33b) implies northeastward-directed flow of formation water, following the surface drainage pattern and flow direction of the Battle River. Hydraulic heads in the Upper Mannville aquifer are generally only slightly higher than those in the Lower Mannville aquifer, indicating relatively good cross-formational hydraulic communication and downward flow. Only in the northeast of the Provost area, hydraulic heads between 550 and 580 m in the Upper Mannville aquifer are significantly higher than those in the underlying Lower Mannville aquifer (350 to 400 m), suggesting that the Clearwater Formation forms an intervening aquitard between the two Mannville aquifers in this area.

Combining the analysis of formation water flow and salinity distribution in the various aquifers, the hydrogeology and flow pattern in the regional-scale study area can be summarized as follows:

- Evaporites of the Prairie Formation (Elk Point Group), the shales and argillaceous limestones of the Waterways Formation (Beaverhill Lake Group), and the Ireton Formation (Woodbend Group), form the laterally continuous Prairie, Waterways and Ireton aquitards, respectively. The shales of the Mississippian Exshaw and Lower Banff formations in the southwest, shales and siltstones of the Clearwater Formation in the northwest, and anhydrite in the southern part of the Wabamun Group form competent aquitards of lesser, local extent.
- The salinity of formation waters varies over an extremely wide range from less than 25 g/l in the Mannville to Winterburn aquifers in the south to more than 300 g/l in the Cambrian to Middle Devonian aquifers.
- Brines from the Upper Devonian aquifers (from west to east: Wabamun, Winterburn and Cooking Lake) discharge(d) into the Lower Mannville aquifer in areas of their respective subcrops, forming a high-salinity plume in the latter (see also Bachu and Underschultz, 1995; Rostron and Toth, 1997; Bachu, 1999; Anfort *et al.,* 2001).
- The plume of high-salinity brine preferentially occupies high-permeability Lower Mannville fluvial sediments deposited in a tributary to the Edmonton Valley.
- Relatively fresher formation water enters the various aquifers from the south.
- The general lateral regional flow direction is northeastward in the Upper Mannville aquifer, southeast-northwest, sub-parallel to the Devonian subcrop edges in the Lower Mannville, Wabamun, and Winterburn aquifers, and flow is convergent towards an area in the Killam Barrier Reef in the Cooking Lake aquifer.

4.2.3 Flow Interpretation

Present-day formation water flow in the regional study area is mainly driven by gravity, through a long-range, basin-scale flow system originating at topographic highs in Montana to the south (Bachu, 1999). North of the study area, formation water flow continues and is channelled northward through the Grosmont carbonate platform of the Woodbend Group, discharging along the Peace River where these carbonates and their equivalents crop out (Bachu, 1999; Anfort *et al.,* 2001). This north-northwestwardly directed basin-scale flow system is joined by a flow system from the southwest in the Beaverhill Lake and Leduc-Cooking Lake aquifers (Figure 34). Based on the relatively high salinity of formation waters, and because of the lack of an identified recharge source and flow-driving mechanism for meteoric water, Bachu (1995) postulated that

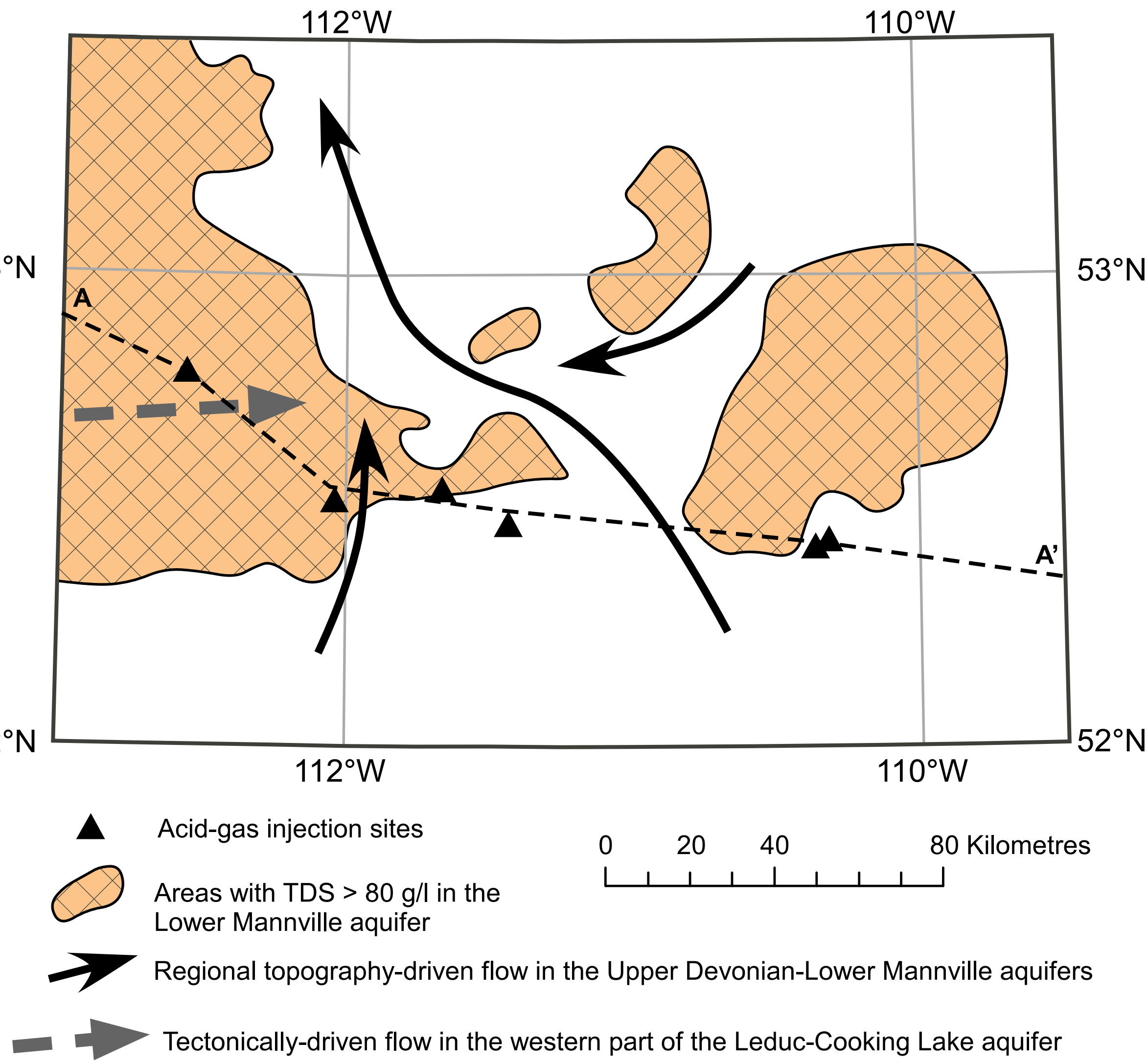


Figure 34. Generalized diagrammatic flow patterns in the regional-scale study area. The line of cross-section A-A' is shown in Figure 35.

the updip northeastward flow component in the Paleozoic aquifers originates from past tectonic compression. This hypothesis is supported by isotopic and fluid inclusion analyses of formation waters and late-stage diagenetic products in both the deformed and undeformed parts of the basin (Nesbitt and Muehlenbachs, 1993; Machel *et al.,* 1996; Buschkuehle and Machel, 2002; Buschkuehle, 2003). The Prairie, Waterways, Ireton, Lower Banff-Exshaw, and Clearwater formations form effective aquitards on a regional scale, but the erosional surface of the pre-Cretaceous unconformity facilitates cross-formational hydraulic communication (Figure 35). Cross-formational flow takes place also in places where the Ireton shales thin above Leduc reefs (Figure 35). Although the origins are different, the common 'sink' for updip flow in the Paleozoic aquifers and downward flow in the Cretaceous aquifers is the 'Grosmont drain' to the north (Bachu, 1999; Barson *et al.,* 2001; Anfort *et al.,* 2001). When looking at the present-day flow patterns in the Lower Mannville aquifer, only the high-salinity plume indicates that updip-flowing Paleozoic brines have entered the Lower Mannville aquifer across the pre-Cretaceous unconformity in the past. However, hydraulic head distributions show that the driving force behind this flow from the Paleozoic has weakened or almost ceased. Only marginally affecting flow in the study area, the downdip flow component in the southeastern corner of the Lower Mannville aquifer is attributed to the re-imbibement of formerly gas-saturated areas by formation water (Michael and Bachu, 2001), and underpressuring created by the erosional rebound of overlying shales (Bachu, 1995).

With respect to the regional hydrostratigraphy and hydrogeology, the acid-gas injection targets in the Provost area are in ascending stratigraphic order in: a) platform carbonates in the Keg River aquifer (Provost-Keg River), b) the Killam Barrier Reef (Galahad) and Leduc platform carbonates (Provost-Leduc) in the Leduc-Cooking Lake aquifer, c) dolomitic limestone in the Wabamun aquifer (Kelsey), and d) fluvial channel sandstones in the Lower Mannville aquifer (Bellshill Lake and Hansman Lake).

4.3 Stress Regime and Rock Geomechanical Properties

Knowledge of the stress regime at any injection site is important for establishing the potential for hydraulic rock fracturing as a result of injection, and for setting limits for operational parameters. Given its tensorial nature, the stress regime in any structure, including the Earth, is defined by the magnitude and orientation of the three principal stresses, which are orthogonal to each other. In the case of consolidated rocks, the fracturing threshold is greater than the smallest principal stress, σ_3, but less than the other two principal stresses, σ_1 and σ_2. If fracturing is induced, fractures will develop in a plane and direction perpendicular to the trajectory of the smallest principal stress. Basin-scale studies of the stress regime in the Alberta Basin suggest that, in most of the basin, the smallest principal stress, σ_3, is horizontal (Bell and Babcock, 1986; Bell *et al*., 1994; Bell and Bachu, 2003). Due to the orthogonality of the stress tensor, this means that the smallest stress is the minimum horizontal stress (σ_3=S_{Hmin}). Rock fracturing occurs at pressures P_b that are greater than the minimum horizontal stress and that can be estimated using the equation:

$$P_b = 3S_{H\min} - S_{H\max} + P_0 + T_0 \qquad (2)$$

where S_{Hmax} is the maximum horizontal principal stress, P_0 is the pressure of the fluid in the pore space, and T_0 is tectonic stress. In the case of injection, the fluid pressure at the well is the bottom hole injection pressure. This equation demonstrates that the fracturing pressure is related to the effective stress (stress less fluid pressure), beside the tensile strength of the rock.

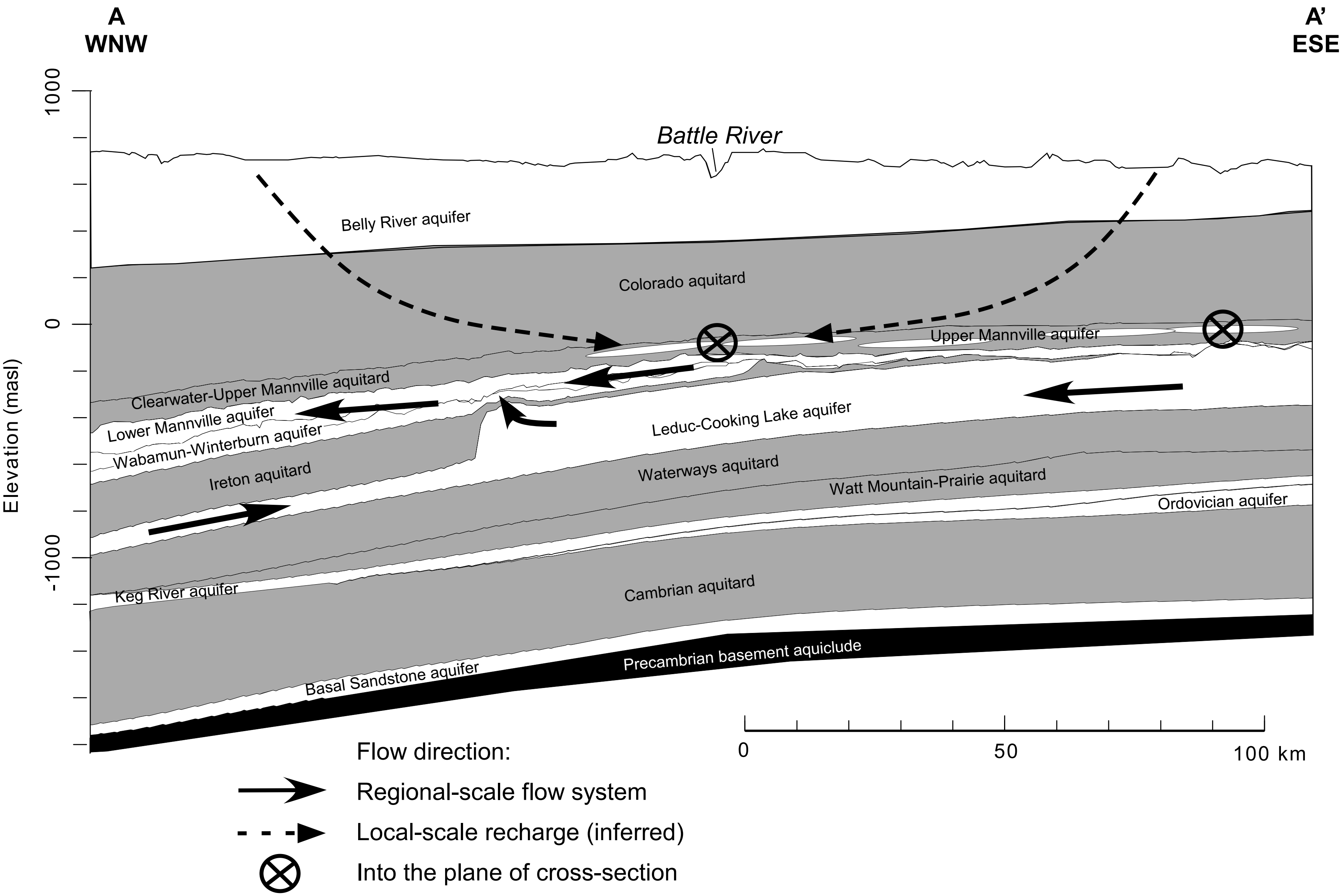


Figure 35. Diagrammatic representation in cross-section of the flow systems in the Cambrian to Upper Mannville Group sedimentary succession in the regional-scale study area. The location of the cross-section is shown in Figure 34.

The minimum horizontal stress, S_{Hmin}, can be evaluated using a variety of tests. The most accurate method for estimating the magnitude of the S_{Hmin} is through micro-fracture testing, but mini-fracturing, leak-off tests and Fracture Breakdown Pressure tests are also used (Bell, 2003; Bell and Bachu, 2003). The maximum horizontal stress cannot be directly measured, but it can be calculated according to the relation:

$$S_{H\max} = \frac{\upsilon}{1-\upsilon}(S_V - P_0) \tag{3}$$

where S_V is the vertical stress and υ is Poisson's ratio, which is determined through laboratory tests on rock samples. The magnitude of the vertical stress, S_V, at any depth coincides with the pressure exerted by the rocks above that point (weight of the overburden), and can be calculated by integrating the values recorded in density logs. Unfortunately, there are no methods for estimating the tectonic stress, T_0, hence it is not possible to estimate the rock fracturing pressure. However, previous studies have shown that in the regional-scale study area the S_{Hmax} is less than S_V (Bell and Babcock, 1986; Bell *et al*., 1994). Thus, estimation of S_{Hmin} and S_V in a well provides loose lower and upper bounds for the fracturing pressure in that well.

If fractures occur, they will develop in a direction perpendicular to the plane of the minimum horizontal stress, hence the need to know the principal directions of the stress field. Horizontal stress orientations can be determined from breakouts, which are spalled cavities that occur on opposite walls of a borehole (Bell, 2003). They form because the well distorts and locally amplifies the far-field stresses, producing shear fracturing on the borehole wall. If the horizontal principal stresses are not equal, the wall rock of a quasi-vertical well is anisotropically squeezed. Caving occurs preferentially aligned with the axis of the smaller S_{Hmin}. More detailed description of the methods used for estimating stress magnitude, gradient and orientation are found in Bell (2003).

No records of stress and/or geomechanical testing in the acid-gas injection wells in the Provost area exist in the public domain (i.e., operator applications to EUB). Leak-off and hydraulic fracturing tests from wells in the regional-scale study area were used to estimate the gradient of the minimum horizontal stress, ∇S_{Hmin}. These gradients were then used to infer the value of the minimum horizontal gradient at the acid-gas injection sites on the basis of stress gradient and depth (Bell, 2003; Bell and Bachu, 2003). Table 2 presents the location, formation, depth and gradient of the minimum horizontal stress determined from tests in Devonian and Mannville Group strata in the regional-scale study area.

Table 2. Gradients of the minimum horizontal stress, S_{Hmin}, determined from tests performed in wells in the Provost regional-scale study area.

Well Location	Formation/Group	Test Type	Depth (m)	Grad(S) (kPa/m)
00/04-22-049-12W4/0	Colony Formation	Hydro-Frac	676	27.1
F1/16-04-046-06W4/0	Mannville Group	Leak-Off	684	17.8
00/14-25-038-17W4/0	Glauconitic SS	Hydro-Frac	1199	15.9
00/06-28-038-07W4/0	Winterburn Group	Leak-Off	2100	17.3

The leak-off and hydro-frac tests in the Mannville Group strata indicate a gradient of the minimum horizontal stress of 15.9 to 17.8 kPa/m (Table 2). However, hydraulic fracturing pressures are always higher than the pressures needed for initiating a fracture (Bell, 2003), and the gradient of 15.9 kPa/m is considered as being representative for the minimum horizontal stress in the sandstones of the Lower Mannville Group in the Provost area.

Carbonate rocks usually are more competent than sandstones, and one would expect that gradients of the minimum horizontal stress for rocks in the Keg River, Woodbend, and Wabamun groups are higher than for the sandstones of the Lower Mannville Group. In the regional-scale study area there is only one test for carbonate rocks from the Winterburn Group (Table 2). Estimates of gradients of the minimum horizontal stress in carbonates of the Wabamun Group at four acid-gas injection sites in the Pembina area to the northwest of the Edmonton area vary between 15.7 and 17.6 kPa/m (Bachu *et al*., 2003b). On the basis of these gradients and of the one test in the Edmonton regional-scale study area, the gradient of the minimum horizontal stress for Devonian rocks at acid-gas injection sites in the Provost area is estimated to be 16.7 kPa/m.

Orientations of the minimum horizontal stress, S_{Hmin}, were determined from breakouts in five wells in the regional-scale study area (Table 3 and Figure 36). The direction of the minimum horizontal stress varies between 120.0^o and 150.5^o (average 138.6^o), in a general southeast-northwest direction. This means that fractures will form and propagate in a vertical plane in a southwest-northeast direction (30°-60.5°; average 48.6^o), perpendicular to the Rocky Mountain deformation front and along the direction of the tectonic stress induced by the Laramide orogeny and by the collision of the Pacific and Juan de Fuca tectonic plates with the North American continent. This preferential fracturing direction was observed previously in coal mines in Alberta (Campbell, 1979), and was similarly determined for overlying Cretaceous rocks in southern and central Alberta (Bell and Bachu, 2003).

Table 3. Orientations of the minimum and maximum horizontal stresses determined from breakouts in wells in the Provost regional-scale study area.

Well Location	Stratigraphic Age	S_{Hmin} Azimuth	S_{Hmax} Azimuth
00/08-11-036-21W4/0	Lower Cretaceous	129.90	39.90
00/16-24-039-21W4/0	Lower Cretaceous	143.00	53.00
00/15-10-040-13W4/0	Lower Cretaceous	130.90	40.90
00/16-10-041-12W4/0	Lower Cretaceous	160.00	70.00
00/11-27-046-21W4/0	Lower Cretaceous	138.20	48.20
00/14-22-050-11W4/0	Lower Cretaceous	146.40	56.40
00/16-24-039-21W4/0	Lower Cretaceous	141.60	51.60
00/08-11-036-21W4/0	Carboniferous	155.30	65.30
00/08-11-036-21W4/0	Upper Devonian	157.10	67.10
00/16-24-039-21W4/0	Upper Devonian	141.00	51.00
00/11-27-046-21W4/0	Upper Devonian	130.00	40.00
00/11-16-044-16W4/0	Middle Devonian	101.00	11.00
00/06-14-048-14W4/0	Middle Devonian	75.80	345.8

Knowledge of the geomechanical properties of rocks in formations affected by acid gas injection is an essential part of the subsurface characterization of any injection site, including the acid-gas injection operations in the Provost area. These properties, in combination with the stress regime, play an important role in evaluating the safety of the operation and avoiding rock fracturing and acid gas leakage into overlying formations. Two parameters are essential to understanding the rock mechanics of an injection site: Young's modulus and Poisson's ratio. A literature review of geomechanical properties provided general values for Poisson's ratio and Young's modulus from rock samples outside of the regional study area. Measurements in each case cover a number of

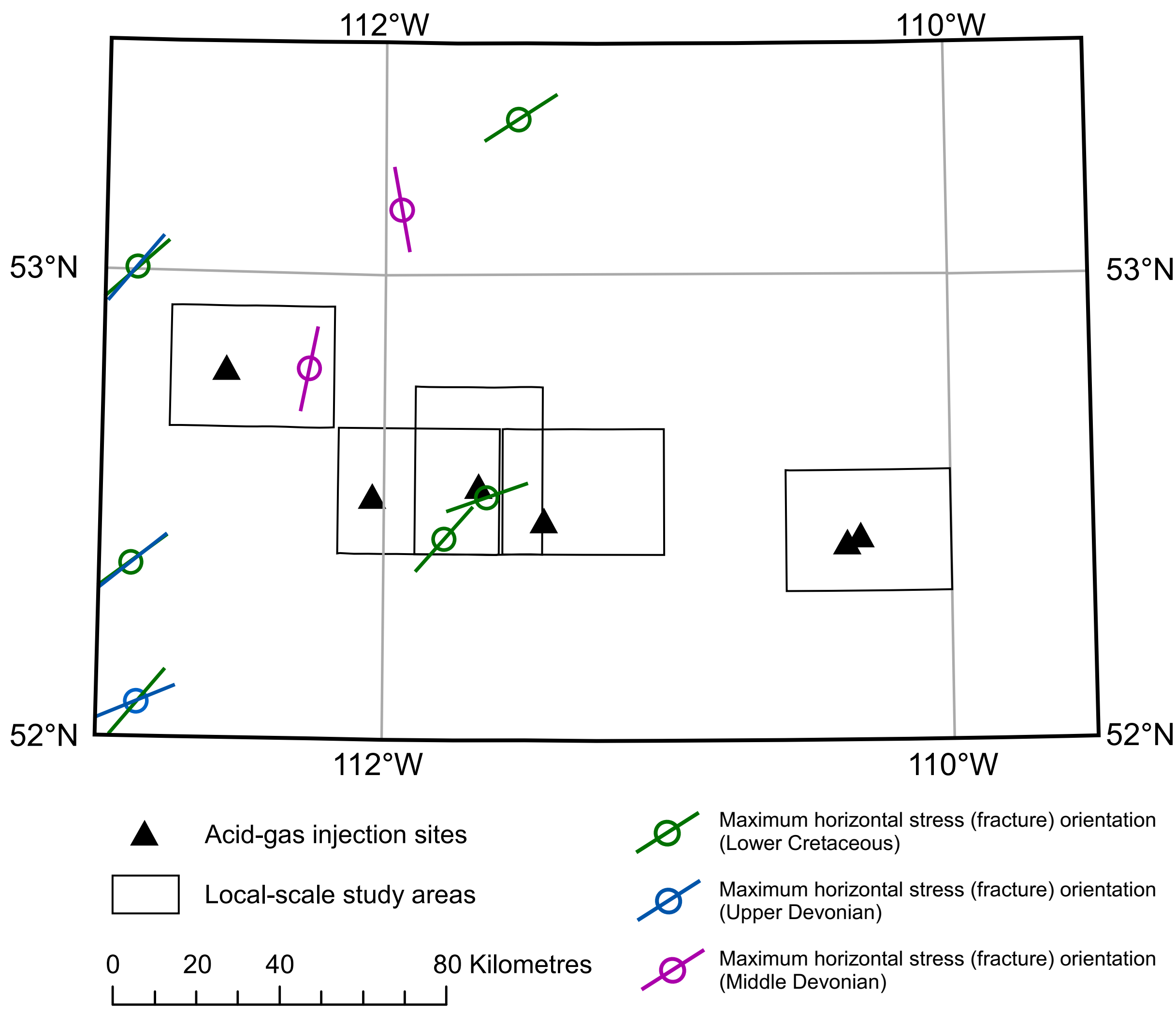


Figure 36. Orientation of horizontal stresses in Middle Devonian to Lower Cretaceous strata in the regional-scale study area. The location of the injection sites and the local-scale study areas is also shown.

samples and a range of values. The value closest to the average of that particular set of measurements was considered as representative and is provided in Table 4. Four of the values given represent Mannville Group parameters, three sandstones and one clay-siltstone. Shale caprock values are represented by a measurement taken in the underlying Jurassic Fernie Group. The carbonate injection interval is characterized by an Upper Devonian dolomite parameter and the shale caprock is represented by a value from the Calmar Formation (Table 4).

Table 4. Geomechanical properties of rocks of interest from the Alberta Basin derived based on data from McLennan *et al*. (1982), Miller and Stewart (1990) and Penson *et al.,* (1993).

Formation	**Group**	**Rock Type**	**Well Location**	**Depth** (m)	**Poisson's Ratio**	**Young's Modulus** (GPa)
Basal Quartz	Mannville	Sandstone	1-12-035-7-W5	2984	0.19	45.4
Basal Quartz	Mannville	Sandstone	9-5-39-3W5	2149	0.18	50.6
Basal Quartz	Mannville	Clay-Siltstone	1-12-035-7W5	2998	0.16	50.2
Glauconitic	Mannville	Sandstone	15-18-39-3W5	2185	0.16	42.2
Calmar	Winterburn	Shale	4-014-16W4	-	0.34	51.8
Nisku	Winterburn	Dolomite	4-014-16W4	1392	0.32	38.8

Young's modulus, E, is defined as the amount of strain (deformation) caused by a given stress, and is a function of the stiffness of the material. Young's modulus is used as an indication of the possible width of fractures. A high Young's modulus correlates to a narrower fracture width. In general, typical Young's modulus values for rocks range from 20 to 82.5 GPa (Jumikis, 1983; Haas, 1989). The Young's modulus values for Mannville sandstone range from 27 GPa to 59 GPa, compared with a value of 30 GPa to 65 GPa for the Mannville siltstone (McLennan *et al.,* 1982). For the Basal Quartz Formation, the Young's modulus was calculated using the following equation:

$$E=2G(1+\upsilon) \tag{4}$$

where the Poisson's ratio, υ, and the shear modulus, G, were measured from static triaxial tests (McLennan *et al.,* 1982). The Glauconitic Formation and Fernie Group values for Young's modulus and Poisson's ratio were both derived from P-wave (Vp) and S-wave (Vs) velocities from sonic logs (Miller and Stewart, 1990). The Young's modulus provided for the Calmar Formation was estimated static Young's modulus and the values in the literature range from 51.8 GPa to 53.3 GPa (Penson *et al.,* 1993). The Upper Devonian carbonate values for Young's modulus were determined from static triaxial bench tests and range from 30 GPa to 67 GPa (Penson *et al.,* 1993).

Poisson's ratio, υ, is defined as the ratio of the strain perpendicular to an applied stress, to the strain along the direction of that stress. It is a measure of the deformation perpendicular to and along the stress being applied to the rock, and indicates the plasticity of the rock. The rock plasticity, expressed by Poisson's ratio, and $S_{Hmin,}$ has a significant effect in determining the rock fracture threshold (see equations 2 and 3). A formation with high S_{Hmin} and Poisson's ratio would likely be an effective barrier to fracture propagation. In general, values for Poisson's ratio for carbonates range from 0.15 to 0.35, for sandstones from 0.1 to 0.3, and for shales from 0.1 to 0.4 (Jumikis, 1983; Lambe and Whitman, 1951; Haas, 1989). The Poisson's ratio for Mannville sandstone ranges from 0.13 to 0.2, compared with a value of 0.12 to 0.32 for the Mannville clay siltstone. The three Basal Quartz values were measured from core samples subjected to representative temperatures and loading conditions (McLennan *et al.,* 1982). The static Poisson's ratio values for the Upper Devonian shale range from 0.3 to 0.35 and for carbonate range from 0.19 to 0.43 (Penson *et al.,* 1993).

5 Local-Scale Setting Of the Acid-Gas Injection Sites in the Provost Area

Because the acid-gas injection sites in Provost are distributed over a large area and various stratigraphic intervals, which have variable characteristics, the geological and hydrogeological characteristics of the these injection sites are described at a local scale in individual specific areas (each defined broadly by the respective oil or gas field they are located in and proximity to each other). The six injection operations (seven sites) were therefore studied in five local-scale study areas (Table 5).

Table 5. Location of acid-gas injection wells in local-scale study areas.

Local-Scale Study Area	Site Name	Injection Well Location	Latitude	Longitude
Bellshill Lake	Bellshill Lake-Blairmore	0414122115000	52.548	-111.668
		0414122212000	52.545	-111.656
		0414122214000	52.548	-111.650
		0414122801000	52.552	-111.663
		0414122803030	52.553	-111.671
		0414122807020	52.557	-111.666
		0414122811020	52.559	-111.676
		0414122908000	52.556	-111.686
		0414123016000	52.563	-111.710
		0414123204000	52.567	-111.704
		0414123302020	52.566	-111.671
		0414123308000	52.570	-111.663
		0414122111020	52.545	-111.672
		0414122112040	52.545	-111.675
		0414122214030	52.552	-111.651
		0414122103040	52.536	-111.670
		0414122802050	52.552	-111.669
		0414122112030	52.549	-111.679
		0414123310000	52.574	-111.669
Hansman Lake	Hansman Lake-Cummings	0404030411000	52.415	-110.381
	Provost-Keg River	0404030405D00	52.416	-110.383
		0404031408002	52.440	-110.319
Kelsey	Kelsey-Wabamun	0444181611020	52.796	-112.561
Galahad	Galahad-Leduc	0414151401002	52.525	-112.047
Thompson Lake	Provost-Leduc	0404103012000	52.471	-111.443

The local-scale study areas encompass all or a part of the Kelsey, Bellshill Lake, Galahad, or Provost hydrocarbon-producing fields, after which the acid-gas injection operations were named (Figure 10). At Hansman Lake and Bellshill Lake, sour water was or is actually injected into the Cummings I oil pool in the Provost field and the Bellshill Lake-Blairmore pool, respectively. At the other operations, acid gas is injected into aquifers that underlie or overlie currently producing horizons. The geology in these specific areas is moderately well known and understood, because drill core, albeit in restricted numbers, is available as a result of exploration for and production of hydrocarbons from Lower Mannville and Upper Devonian strata. Maps showing the depth to and the structure top of the respective injection units are not presented at the local scale. This information is readily available from corresponding regional-scale maps (Figures 16, 18, 20 and

22). In turn, isopach maps and/or local-scale cross-sections are presented, since information about the thickness of the injection unit and the overlying aquitard is relevant at the local scale.

The actual in-situ formation water density in the local-scale study areas generally differs from the regional average. However, for the calculation of hydraulic head values at the regional scale a reference density of 1060 kg/m^3 was used (see Section 4.2.2) and this value will be used at the local scale as well. This allows for the comparison between contour maps of hydraulic heads on the regional and local scales, but does not significantly affect the accuracy of the flow analysis (Bachu and Michael, 2002).

Rock properties relevant to the flow of formation fluids and injected acid gas that were used in the local-scale characterization are porosity and permeability. The core-scale porosity values were up-scaled to the well scale using the weighted arithmetic average. Permeability values were up-scaled to the well scale using a power-law average with a power of ω=0.8 (Desbarats and Bachu, 1994). Representative values presented in tables in the following sections present the statistics of the well-scale averaged porosity and permeability values.

5.1 Bellshill Lake

The local-scale study area is defined between 52.40^{o}N to 52.76^{o}N and 111.44^{o}W to 111.89^{o}W (Townships 40-43, Ranges 11-13W4). It includes 19 injection wells that are supplied with acid gas by the Bellshill Lake gas plant located at Section 28- Township 41- Range 12W4 in the centre of the study area (Figure 10). Injection of acid gas mixed with water takes place into clastic sediments of the Basal Quartz Member, which is the lowermost unit of the Lower Mannville Group, as well as carbonates of the Wabamun and Winterburn groups (Figure 12, Appendix 1).

5.1.1 Geology

The sandstones of the Basal Quartz/Ellerslie Member (Lower Mannville) range in thickness between 20 and 80 m within the local-scale study area and are on average 55 m thick in the injection area (Figure 37) with a net pay of 5 m. Within the outline of the Bellshill Lake channel, the sediments consist of grey to brown sandstones, which often have a "salt and pepper" appearance, are fine-grained, silty, moderately sorted, and porous with well-developed interbeds of grey silty shale. The rocks consist of predominantly quartz, and minor amounts of pyrite, clay minerals, plagioclase feldspars, and traces of various other minerals. Grain-supported angular quartz particles occur in a patchy clay matrix with secondary opaque pyrite cements. The rocks are extremely porous and permeable with up to 26% porosity. The porosity type is mainly intergranular and the grain and pore sizes are in the 10 to 50 μm range (Figure 38). Correlations suggest that these sandstones were deposited in a fluvial environment close to a delta, indicating brackish conditions (Bannerjee and Davies, 1988). Off-channel deposits in the northeast and southwest corners of the Bellshill Lake area are generally thin and consist of fine-grained siltstone and shale.

The injection interval in the Lower Mannville Group is overlain by up to 100 m thick shale/sand/silt packages of the Upper Mannville Group (Figure 39), which are not further subdivided, but the lower parts can be considered equivalents to the Clearwater Formation shales. The Ellerslie Member is underlain by the Upper Devonian Wabamun Group, which consists of mostly tight limestones more than 150 m in thickness (Figure 40).

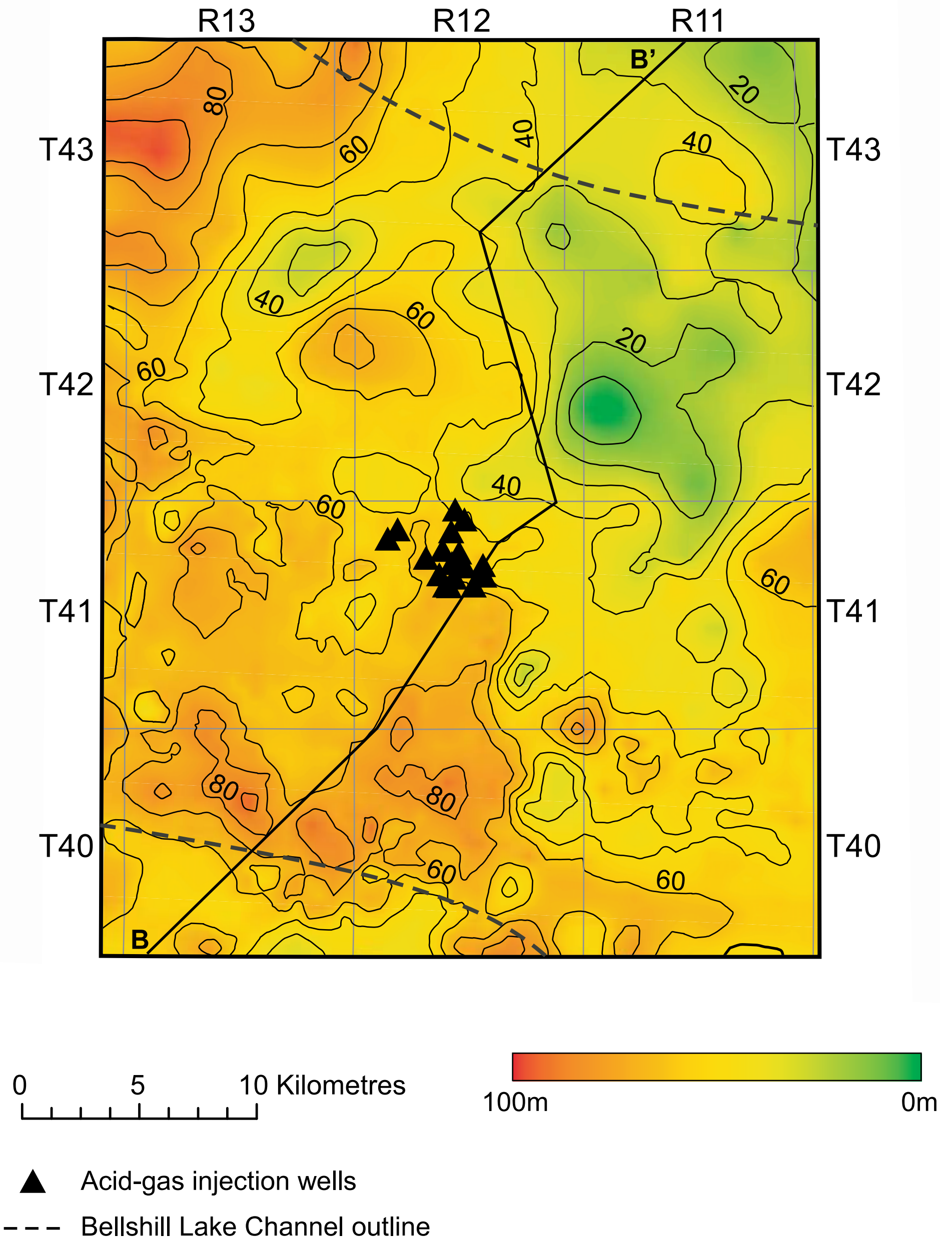


Figure 37. Isopach map of the Lower Mannville Group in the Bellshill Lake local-scale study area. The location of the injection wells is also shown. Contour interval = 10 metres. Cross-section B-B' is shown in Figure 40.

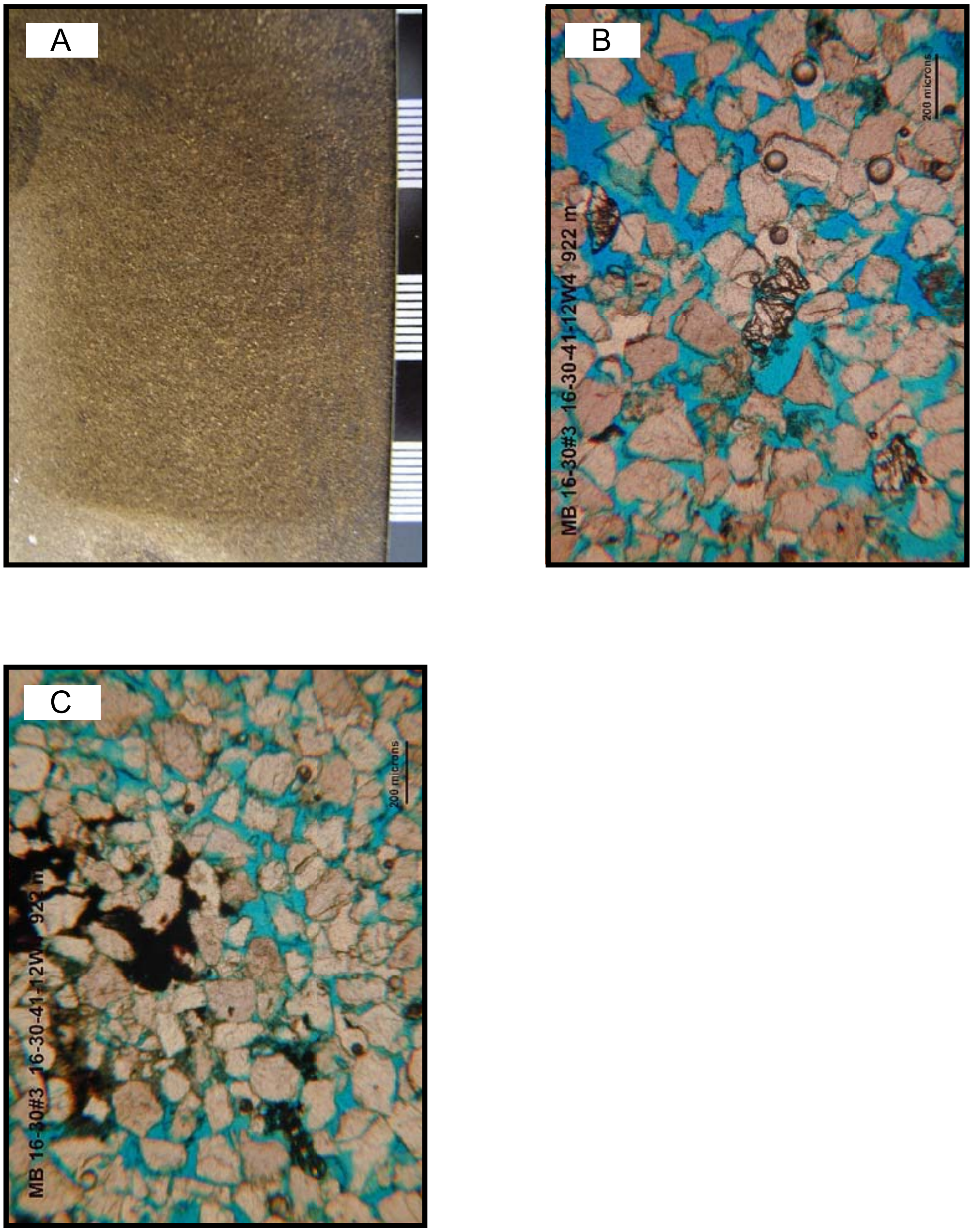


Figure 38. Core and thin section photographs of the Basal Quartz/Ellerslie Member in the Bellshill Lake area. The rocks consist of homogeneous sandstones (Photo A) with grain-supported angular quartz particles (Photo B). The inter-particle porosity is very high as indicated by the blue stain in the thin sections (Photos B and C).

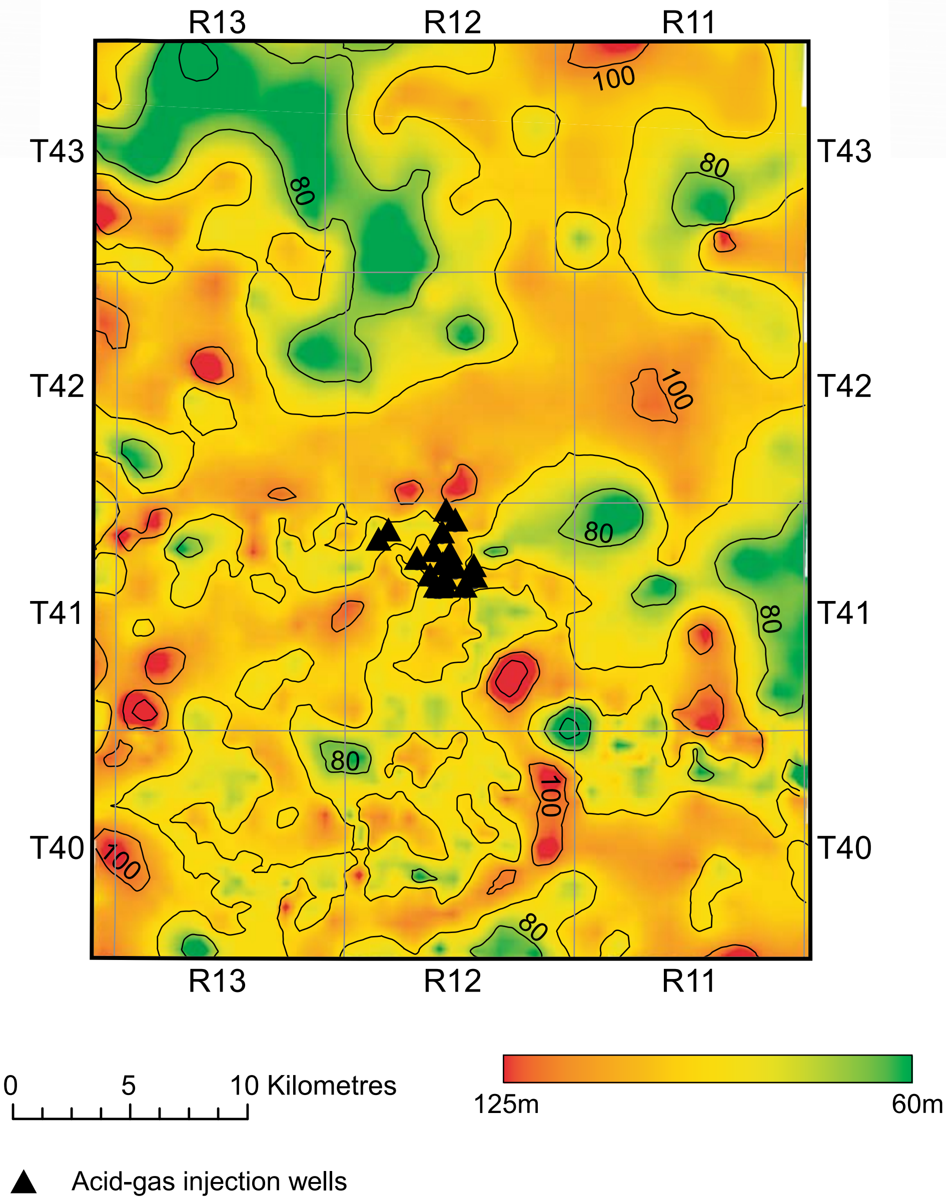


Figure 39. Isopach map of the Upper Mannville Group in the Bellshill Lake local-scale study area. The location of the injection wells is also shown. Contour interval = 10 metres.

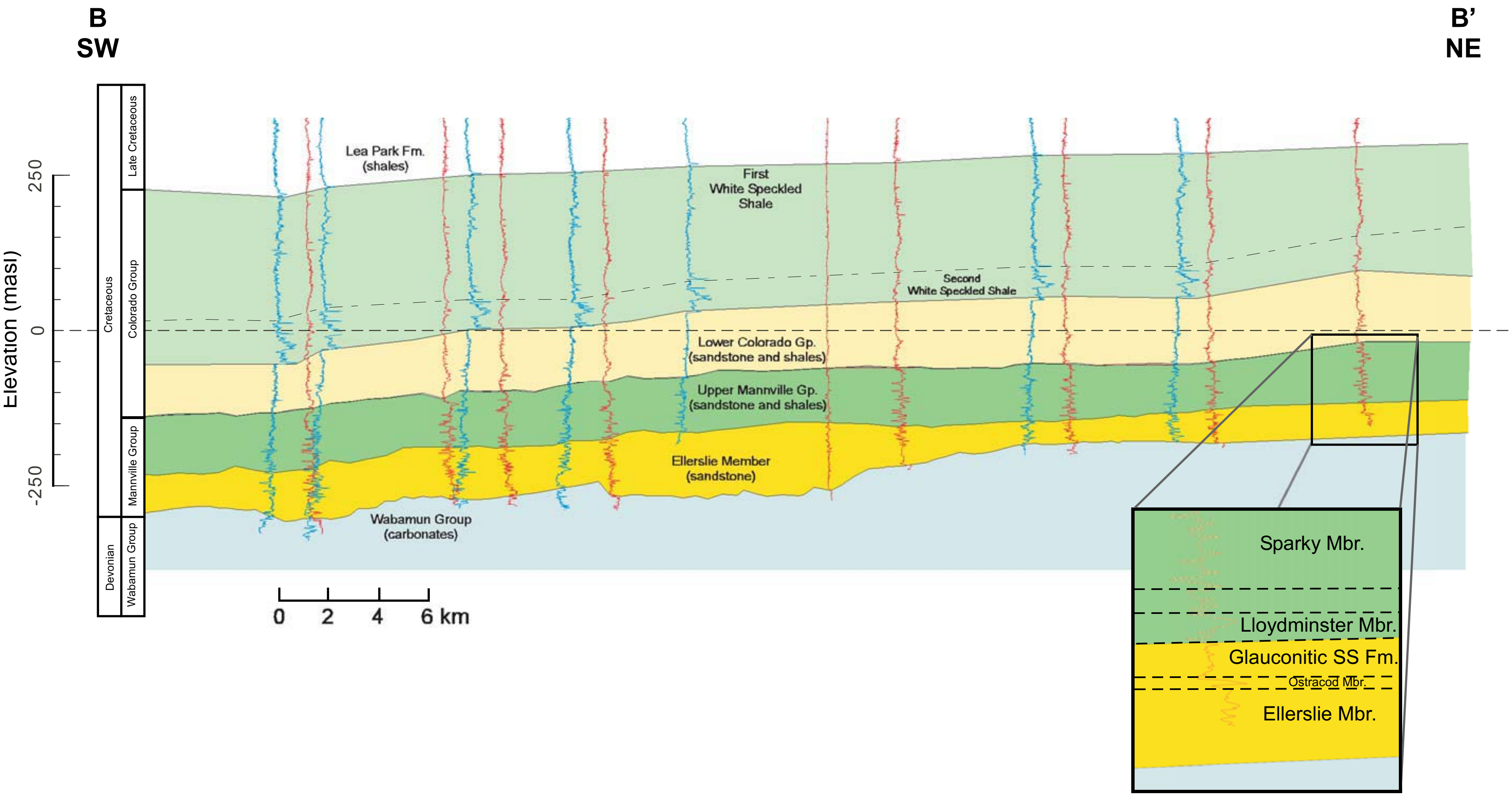


Figure 40. Local-scale cross-section through the Cretaceous succession in the Bellshill Lake area. The Lower Mannville injection horizon is the Ellerslie Member Sandstone. The location of the line of cross-section is shown in Figure 37.

5.1.2 Hydrogeological Characteristics and Rock Properties

Chemistry of Formation Waters

Seventy-seven chemical analyses of Lower Mannville Formation water exist in the local-scale study area. The major constituents are sodium (27 g/l) and chloride (47 g/l), making up 96% of the total dissolved solids (Table 6). Magnesium, calcium, sulphate and bicarbonate are present in minor concentrations (Figure 41a). The salinity decreases slightly from > 90 g/l in the centre to approximately 75 g/l and less than 60 g/l along the northern and southern boundaries of the study area, respectively (Figure 42). The average in-situ density of formation water in the Lower Mannville aquifer in the local-scale study area was estimated to be 1053 kg/m^3 using the methods presented in Adams and Bachu (2002).

Table 6. Summary of major ion chemistry of Lower Mannville brines in the Bellshill Lake area (concentrations in g/l).

	Na	K	Ca	Mg	Cl	SO_4	HCO_3	TDS
Minimum	20.3	0.8	1.4	0.4	35.7	0.0	0.1	59.2
Maximum	30.9	0.1	4.3	1.5	58.7	0.4	1.9	95.0
Average	26.5	1.3	2.4	0.9	47.4	0.1	0.8	77.7

Pressure Regime

Hydraulic heads, calculated with a reference density of 1060 kg/m^3, decrease from above 425 m in the south and in the north of the study area to less than 400 m in the west (Figure 43), generally indicating westward flow. Higher hydraulic heads are observed outside the area of channel sand deposition, and the pattern of hydraulic-head contours suggests channelling of formation water flow along the paths indicated by the arrows in Figure 43. Formation water flow diverges in the vicinity of the acid-gas injection wells, resulting in west-southwestward and east-northeastward flow, respectively.

The recorded pressures in the Lower Mannville aquifer are plotted versus elevation in Figure 44 and compared to pressures in over- and underlying formations. Overall, the data distribution indicates a potential for vertically downward flow from the Upper Mannville aquifer (475 - 550 m hydraulic head) into the Lower Mannville (375 - 450 m hydraulic head) and Devonian (+/- 400 m hydraulic head) aquifers. Pressures equivalent with a hydraulic-head equivalent of approximately 500 m were measured in the southern corner of the Lower Mannville aquifer, which, being located outside the area of major channel sand deposits, appears to be partly isolated. The offset of pressure data measured in the Upper versus the Lower Mannville aquifer indicates that there exists only weak, vertical hydraulic communication between the two aquifers. Pressures in the underlying Devonian Wabamun, Winterburn and Leduc-Cooking Lake aquifers plot along a similar pressure-elevation trend as pressures in the Lower Mannville aquifer, which suggest that these aquifers might be in vertical hydraulic communication. In fact, acid gas injection generally occurs through open-hole completions, covering Lower Mannville to Winterburn strata, and no major aquitards are observed in this stratigraphic interval.

a. Lower Mannville aquifer - Bellshill Lake

b. Lower Mannville aquifer - Hansman Lake

c. Lower Mannville-Wabamun aquifer - Kelsey

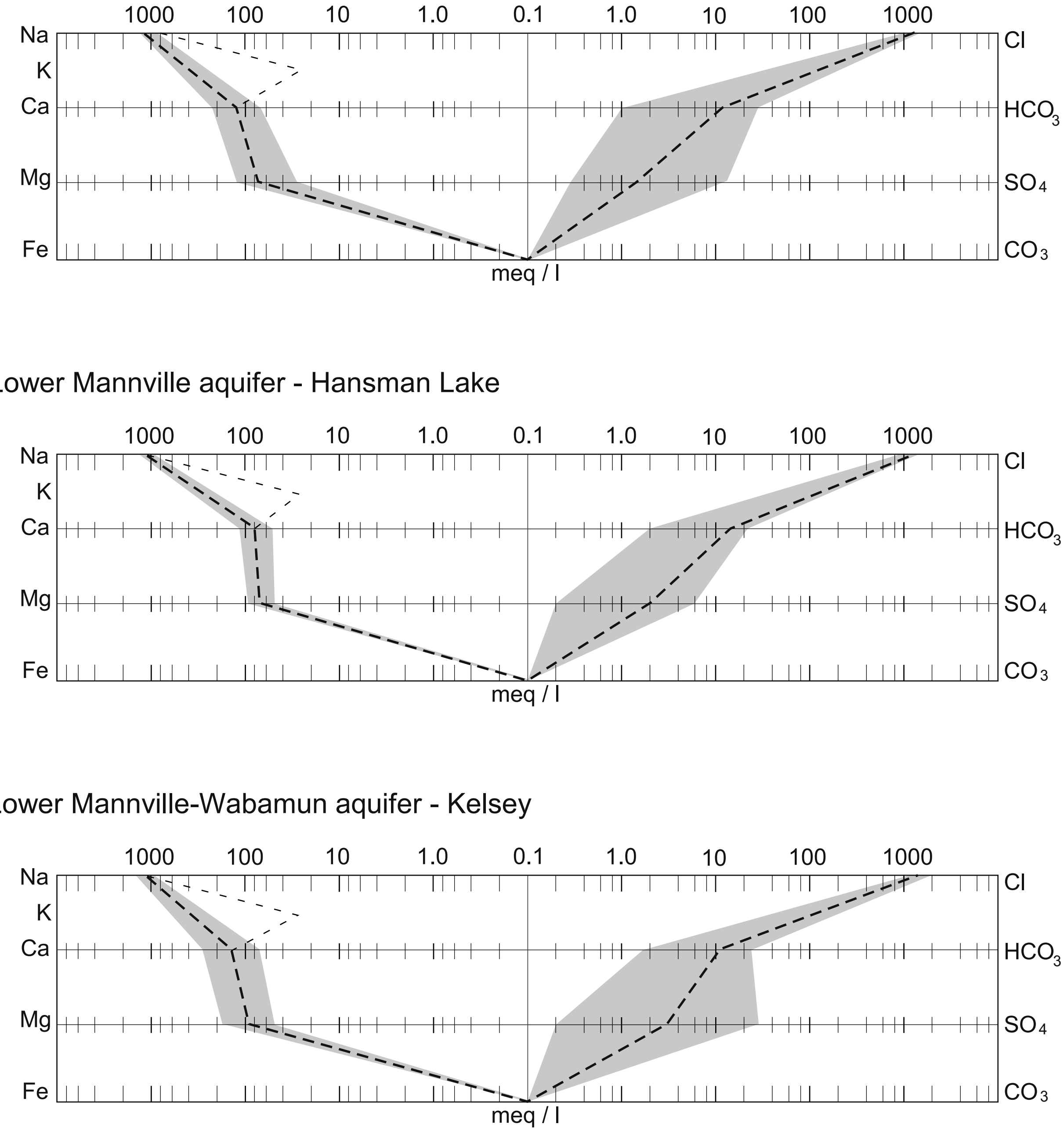


Figure 41. Stiff diagrams of formation waters from the Lower Mannville aquifer in the: a) Bellshill Lake area (76 analyses), b) Hansman Lake area (20 analyses) and c) Kelsey area (Lower Mannville-Wabamun aquifer, 57 analyses). The grey-shaded area shows the range, the bold dashed line represents the average concentrations in meq/l (milliequilvalents per litre) and the thin dashed line represents the potassium concentration.

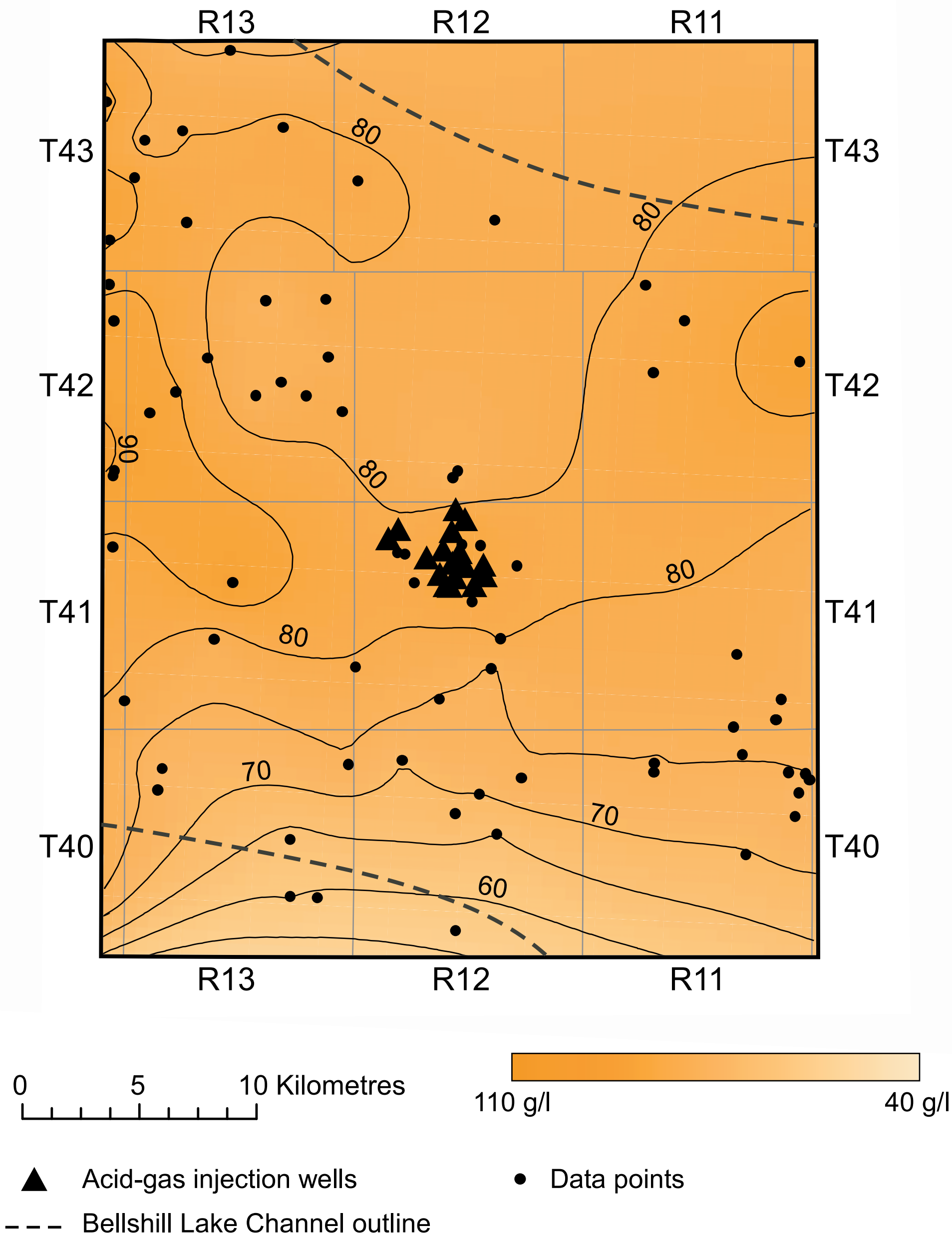


Figure 42. Distribution of salinity (g/l) in the Lower Mannville aquifer in the Bellshill Lake local-scale study area. The location of the injection wells is also shown. Contour interval = 5 g/l.

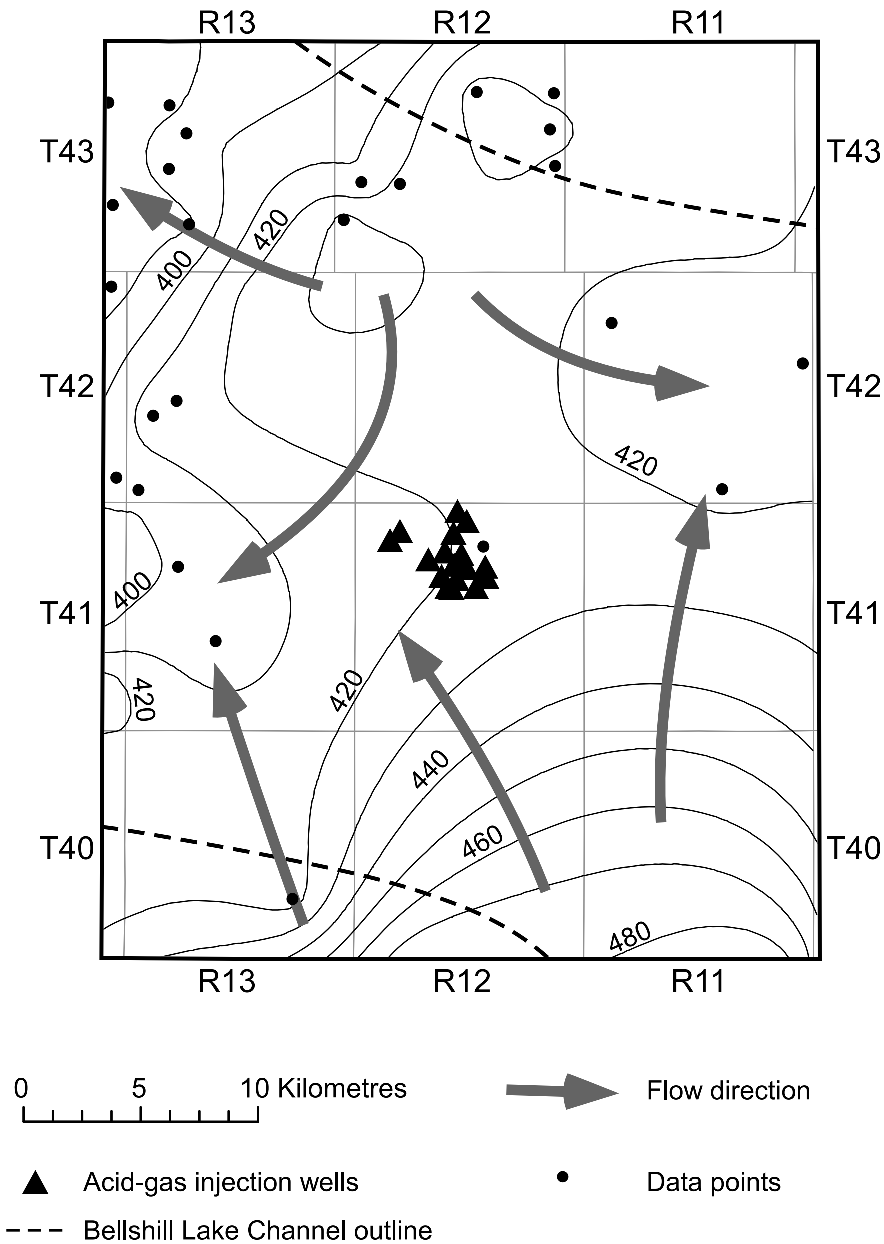


Figure 43. Distribution of hydraulic heads (m) with inferred flow direction of formation water in the Lower Mannville aquifer in the Bellshill Lake local-scale study area. The location of the injection wells is also shown. Contour interval = 10 metres.

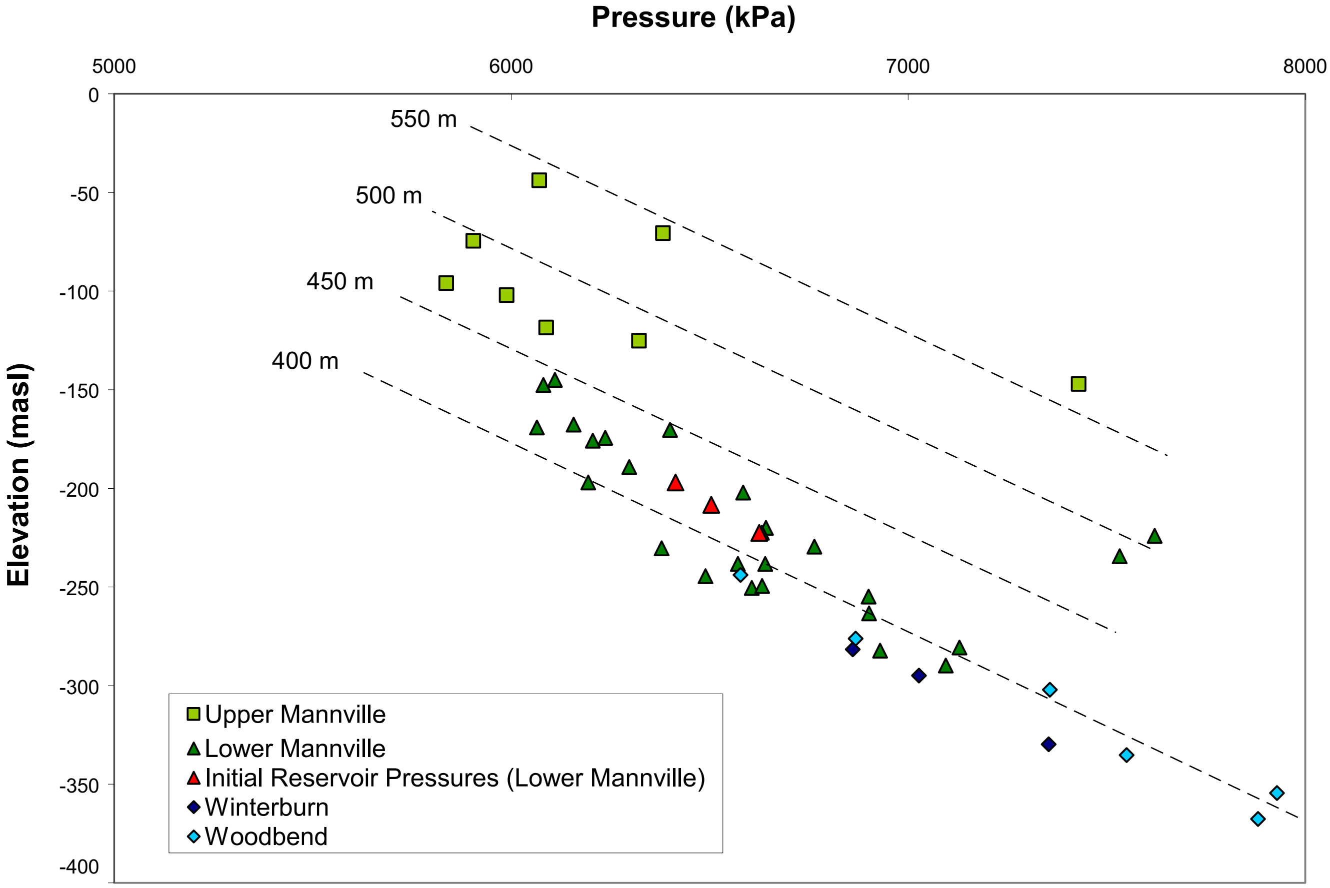


Figure 44. Distribution of pressure versus elevation in the injection strata (Lower Mannville) and adjacent formations in the local-scale study area of the Bellshill Lake acid-gas injection operation. The dashed lines delineate pressure-elevation trends with equal hydraulic-head values and the potential for vertical flow may be inferred perpendicular to those lines from high to low values.

Rock Properties

The well-scale porosity and permeability values for the Ellerslie and Ostracod formations, which form the aquifer and the over-/underlying Glauconitic Formation and Wabamun Group, are shown in Table 7. Also shown are permeability values calculated from drillstem tests that were performed in the Lower Mannville and Wabamun aquifers. Core plug measurements generally are biased toward higher porosity and permeability values. The average values of porosity (25%), horizontal permeability (748 mD) and vertical permeability (433 mD) are highest in the Ellerslie Formation, which is the main aquifer unit. In comparison, porosity (20%) and vertical permeability (4-9 mD) values in the over- and underlying formations are significantly lower. Significantly higher horizontal versus vertical permeability values were measured in the Ostracod Formation and the Wabamun Group, indicating preferred flow in the horizontal direction. In comparison, median permeability values calculated from drillstem tests range between 3 and 6 mD in the Wabamun (2 wells) and Lower Mannville (85 wells) aquifers, respectively. The scarcity of data from the Wabamun limits the comparability with data from the Lower Mannville aquifer, the latter showing a much larger range from minimum (0.01 mD) to maximum (17,354 mD) calculated permeability values.

Table 7. Well-scale porosity and permeability values obtained from measurements in core plugs from the Glauconitic (89 wells), Ostracod (110 wells), Ellerslie (115 wells) formations, and the Wabamun Group (3 wells), and permeability values calculated from 75 drillstem test analyses in the Bellshill Lake area.

Formation	Porosity (%)			Horiz. Perm. (mD)			Vert. Perm. (mD)			DST Perm. (mD)		
	Min	Max	Avg	Min	Max	Median	Min	Max	Median	Min	Max	Median
Glauconitic	8	29	20	0.2	2370	37	0.14	2850	9	0.1	17354	9
Ostracod	12	34	25	0.3	6410	518	0.21	4650	404			
Ellerslie	13	32	25	7.0	5660	748	0.98	4120	433			
Wabamun	10	28	19	24	3110	572			4	3		

Flow of Formation Water

In the Bellshill Lake area, the Upper Devonian Wabamun and Winterburn aquifers are in direct hydraulic communication with the overlying Lower Mannville Group along the pre-Cretaceous unconformity due to the absence of extensive intervening aquitards. However, core tests and DSTs indicate that the permeability in Lower Mannville strata is higher than in the Devonian aquifers. Therefore, the Lower Mannville aquifer is the preferred flow unit with relatively higher flow rates and velocities. Further channelling of flow occurs due to lateral permeability differences within the Lower Mannville aquifer between coarse-grained channel sands and finer-grained off-channel deposits. Regional-scale topography appears to be driving less saline formation water flow initially northward into the Bellshill Lake area, where it is reflected west-southwestward and east-northeastward as a result of channel geometry. The relatively high salinity of formation water, especially in the centre of the Lower Mannville channel sands, suggests that the Lower Mannville aquifer is relatively isolated through the Colorado shale aquitard from direct recharge and dilution with fresh meteoric water.

5.2 Hansman Lake

The Hansman Lake local-scale study area extends from 52.32^{o}N to 52.58^{o}N and 110.00^{o}W to 110.58^{o}W (Townships 39-41, Ranges 1-4W4) (Figure 10). Two acid-gas injection operations, one of them inactive, are located in the study area. The Hansman Lake operation was rescinded in

1997 and injection took place through a single well in the Cummings Member of the Lower Mannville Group (Figure 12, Appendix 1). At the Provost-Keg River site, acid gas currently is injected into carbonates of the Keg River Formation of the Middle Devonian Elk Point Group. Both geological and hydrogeological data for the Keg River Formation are very limited in the Hansman Lake area because only a few wells penetrate the Elk Point Group. The only pressure and chemistry data from the Keg River Formation that exist in the Hansman Lake area are from the injection site itself and will therefore be discussed mainly in the site specific characterization of the Provost-Keg River acid-gas injection operation.

5.2.1 Geology

Lower Mannville Group

The major injection unit in the Hansman Lake local-scale study area was the lower Mannville Cummings Member. The Cummings Member is the upper most part of the Lower Mannville Group and is equivalent to the Wabiskaw sandstone in the Athabasca area to the north. Nauss (1945) described the Cummings Member as principally dark grey to black shale containing abundant pyrite and foraminifera. Beds of salt-and-pepper sandstone are common and a coal seam occurs near the base in the type section. In the local-scale study area, the Cummings Member is a clean, bar-type sandstone and the term Cummings is more often used in relation to this sandstone than the shales described by Nauss. The thickness of the Cummings varies between 10 and 70 m, with an average of ca. 50 m in the injection area (Figure 45a) with a net pay of 2 m. The rocks consist predominantly of quartz, chert, feldspar and minor amounts of various other minerals, which could not be identified. The arenitic texture is grain-supported with only minor contacts between the grains. The rocks are extremely porous and permeable with up to 30% porosity. The porosity type is mainly intergranular, and some channel porosity. The grain and pore sizes are in the 10 to 150 μm range (Figure 46). Because the strata consist primarily of thin, coarsening-upward successions of shales, siltstones and lenticular sandstones, it is assumed that deposition took place in a low-energy, brackish, subaqueous environment (Finger, 1983; James, 1985). Evidence of tidal activity is also common. The sandstones of the Cummings Member continue downwards into channel sandstones of the Dina Member, together forming the Lower Mannville aquifer in the Hansman Lake area.

The injection interval is encased in a more than 100 m thick sequence of shale, sandstone and siltstone of the Upper Mannville Group, of which the Lloydminster Member is the lowermost unit (Figure 47). The Lower Mannville Group sediments are underlain by the Upper Devonian Woodbend Group, which consists of mostly tight, shallow marine limestones, more than 150 m in thickness (Figure 47).

Keg River Formation

The second injection unit in the Hansman Lake local-scale study area is the Middle Devonian Keg River Formation (Provost-Keg River). In the local-scale study area, the thickness of the Keg River Formation is about 30 m (Figure 47) with a net pay of 2 m. The Keg River injection horizon consists of brown to dark grey-brown, slightly bituminous, argillaceous, cryptocrystalline, fossiliferous, dense dolostones and limestones that were deposited on a moderately shallow marine open shelf or ramp (Campbell, 1992). Locally, part or all of the Keg River Formation consists of dolomite with occasional poor to moderate vuggy and inter-crystalline porosity of up to 6%. Bituminous partings can be common. Crinoids, brachiopods, ostracods, gastropods and tentaculitids are common, and several corals like thamnopora,

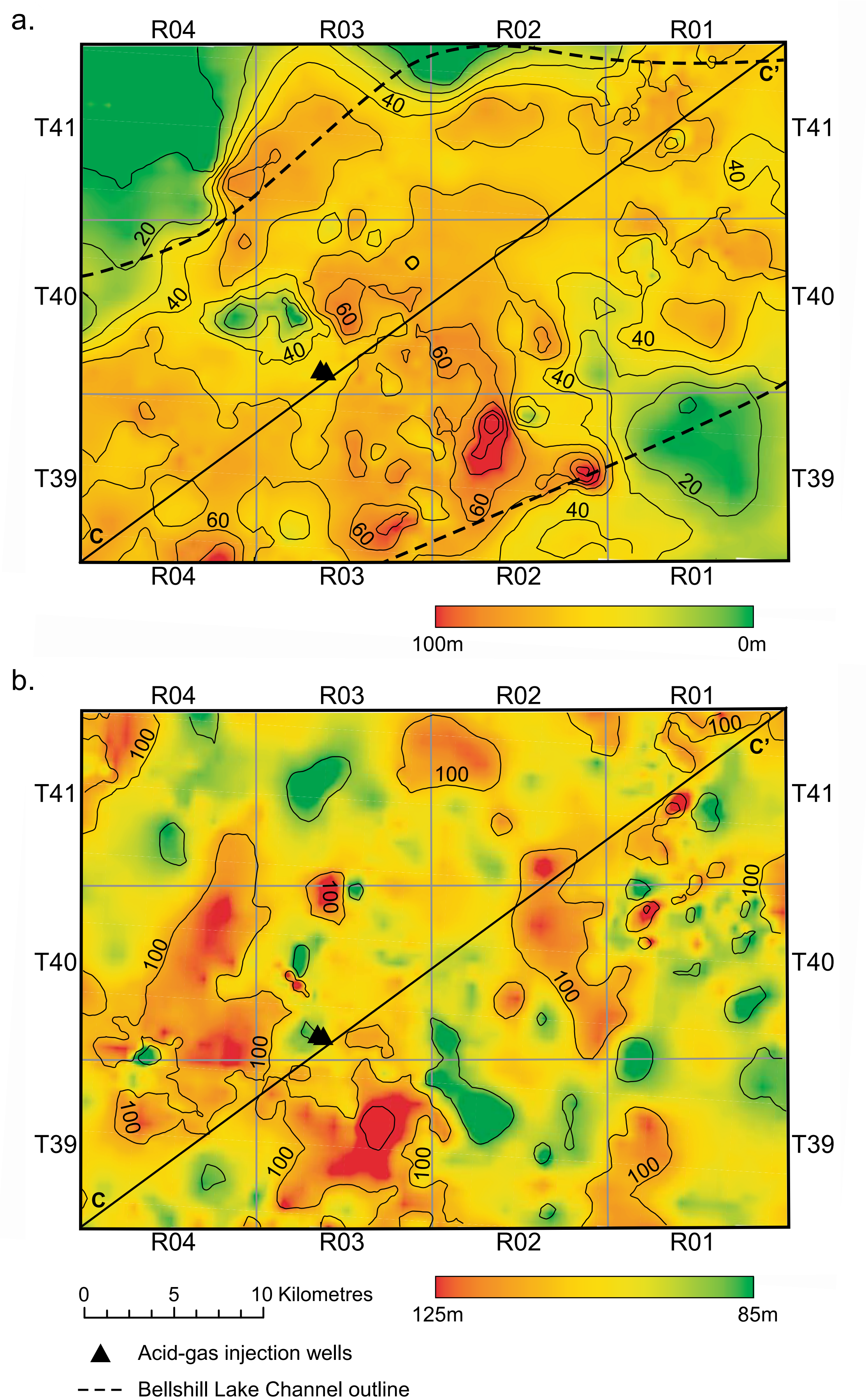


Figure 45. Isopach maps in the Hansman Lake local-scale study area: a) Cummings Member and b) Upper Mannville Group. The location of the injection wells is also shown. Contour interval = 10 metres. Cross-section C-C' is shown in Figure 47.

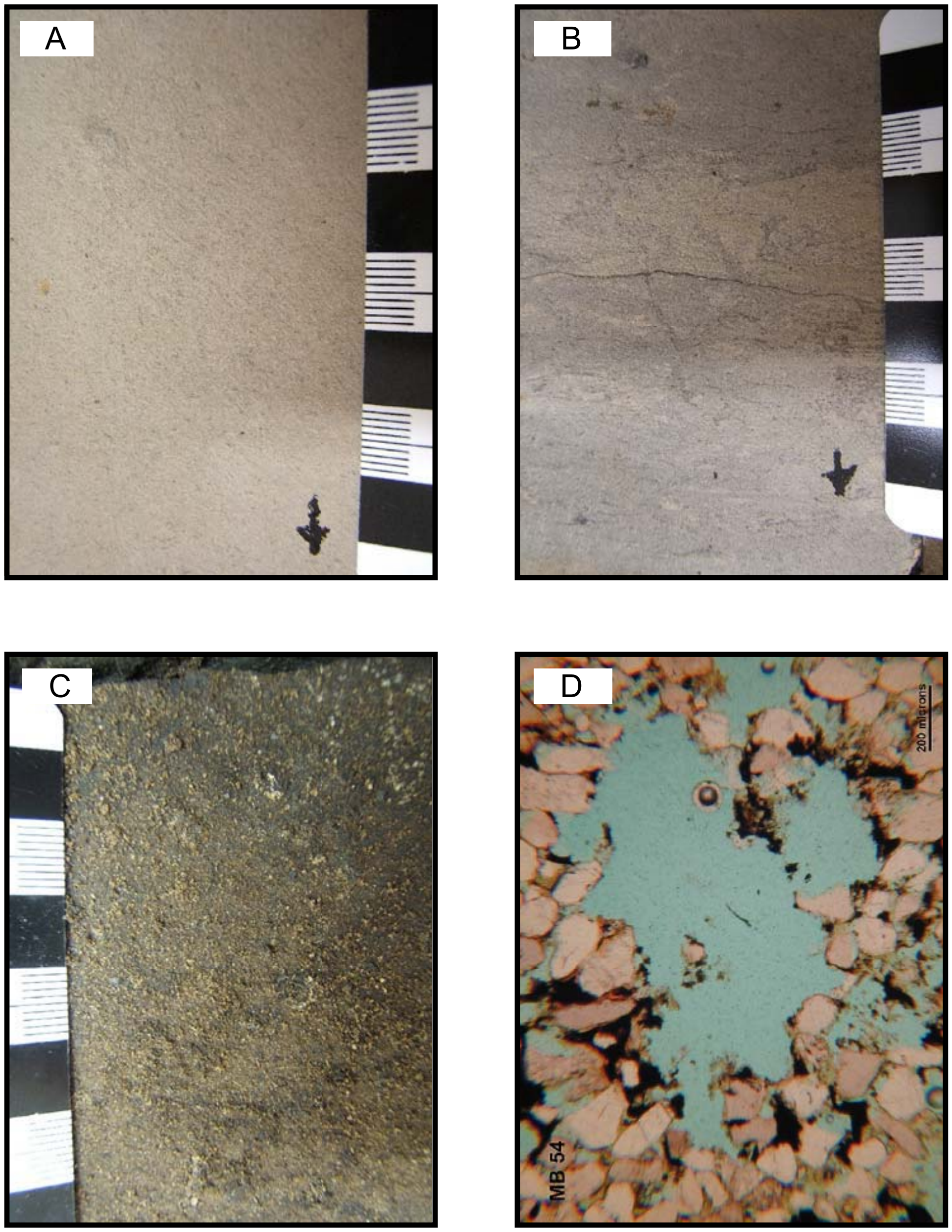


Figure 46. Core and thin section photographs of the Cummings Member in the Hansman Lake area. Fine-grained, homogenous siltstones (Photo A) gradually change to wavy-layered silt- to sandstone (Photo B) and is underlain by an oil-saturated sandstone (Photo C). The rocks are composed of angular to subangular grains of quartz with minor amounts of orthoclase and chert, with a grain supported fabric but only minor contact between grains. The inter-granular, channel and porosity is very extensive and can best be seen in the thin section photograph (Photo D).

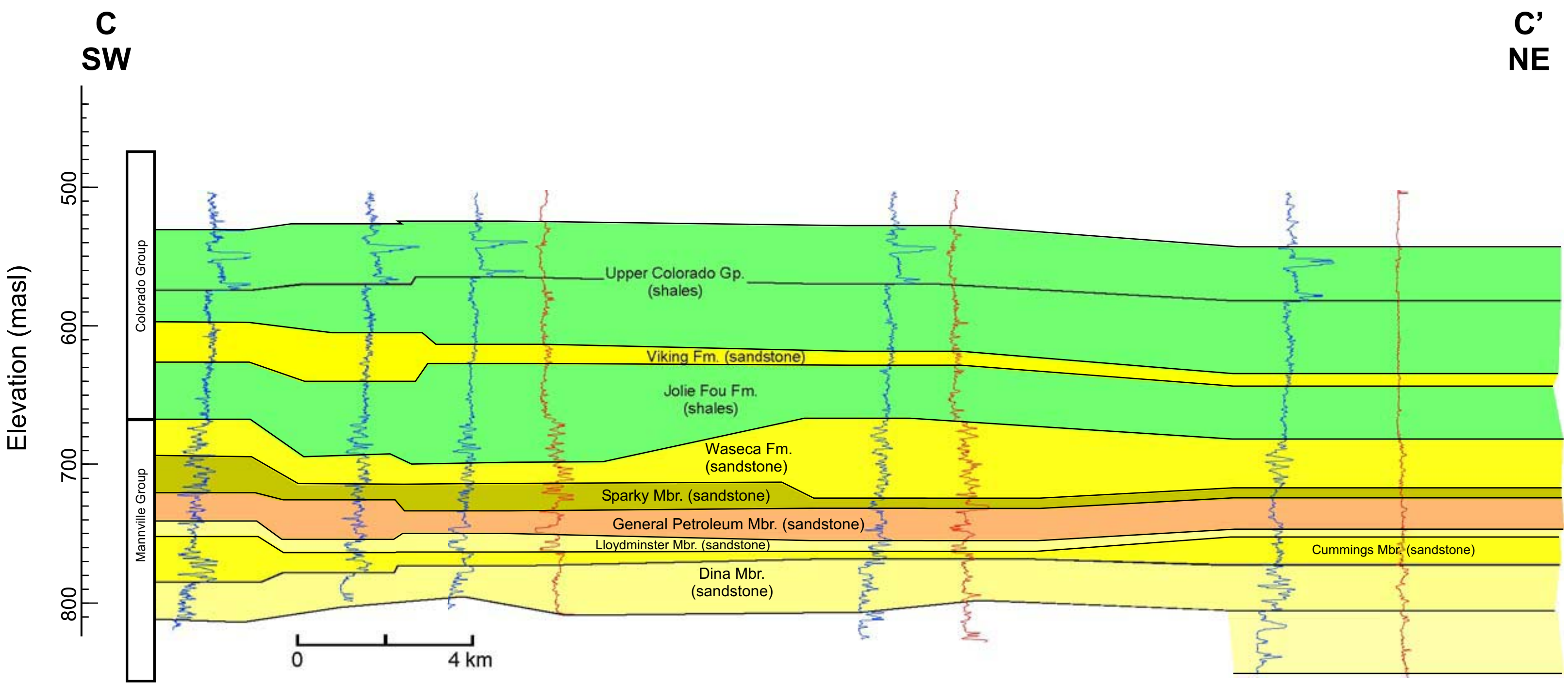


Figure 47. Local-scale cross-section of the Cretaceous succession through the Hansman Lake area. The injection horizon is the Cummings Member of the Lower Mannville Group. The location of the line of cross-section is shown in Figure 45.

cystiphyllum, platy alveolites, and syringopora and lamellar to irregular stromatoporoids form up to 30% of the framework (Figure 48).

The injection horizon is overlain by more than 100 m evaporites (anhydrite and salt) of the Prairie Formation (Figure 49). The Keg River Formation is underlain by shales of the Ashern Formation and by Cambrian/Ordovician limestones and/or dolostones, which have a combined thickness of several 100 metres (Figure 47).

5.2.2 Hydrogeological Characteristics and Rock Properties

Chemistry of Formation Waters

The major constituents of Lower Mannville formation water in the Hansman Lake area as determined from 20 analyses are sodium (27 g/l) and chloride (46 g/l), making up 96% of the total dissolved solids (Table 8). Magnesium, calcium, sulphate and bicarbonate are present in minor concentrations (Figure 41b). Note the sulphate concentrations < 0.8 g/l, which are low compared to other areas and aquifers. In the Hansman Lake area, the salinity of formation water gradually increases from < 50 g/l in the southeast to approximately 90 g/l in the northwest (Figure 50a). The average in-situ density of formation water in the local-scale study area was estimated to be 1053 kg/m^3 using the methods presented in Adams and Bachu (2002).

Only limited data exists for the Keg River aquifer in this area. The salinity of the Na-Cl type formation water at the injection site is approximately 340 g/l (Table 8) and the in-situ density is 1220 kg/m^3.

Pressure Regime

Hydraulic heads in the Lower Mannville aquifer, calculated with a reference density of 1060 kg/m^3, have a small range (414 - 445 m), which corresponds to a low hydraulic gradient in the local study area (Figure 50b). The hydraulic head contours suggest that the flow of formation water, although subtle, is generally towards the west, following the regional flow pattern in the Lower Mannville aquifer (Figure 33). Closed highs of hydraulic-head contours (> 440 m) are probably due to local topographic recharge in these areas. The distribution of pressure versus elevation shows that the potential for flow is downward from the Upper Mannville into the Lower Mannville and the Devonian aquifers in the Hansman Lake area (Figure 51).

Rock Properties

The average porosity (25%), the median horizontal permeability (582 mD), and the median vertical permeability (147 mD) of the Cummings Formation are slightly lower than the respective values in the overlying Lloydminster and underlying Dina formations (Table 9). Permeability values calculated from drillstem testing in the Lower Mannville aquifer range from 0.3 to 320 mD with a median value of 9 mD.

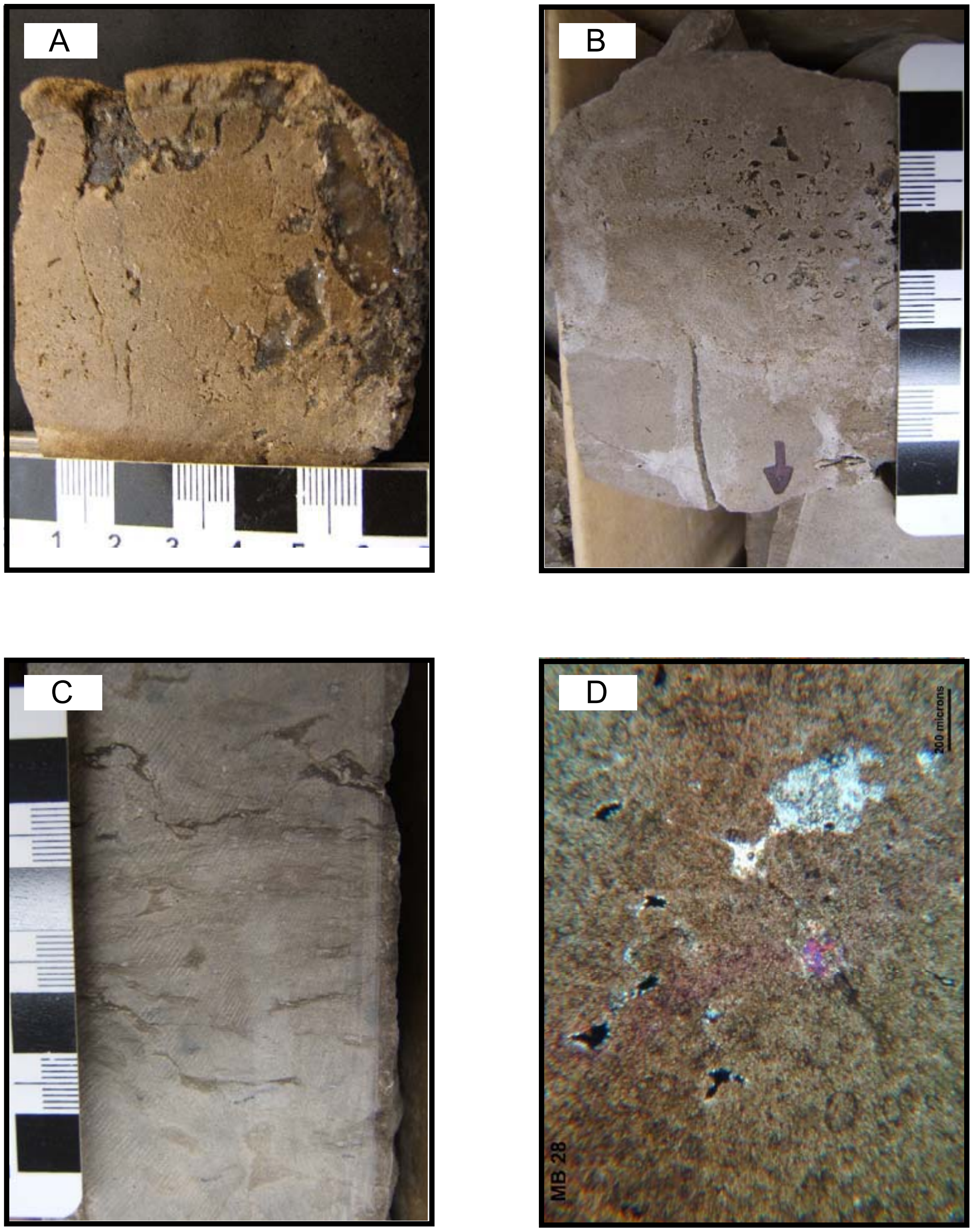


Figure 48. Core and thin section photographs of the Keg River Formation carbonates in the Hansman Lake area. Coarse-grained dolostones (Photo A) with halite-filled vugs change to porous, coarse-grained fossiliferous dolostone (Photo B), which is underlain by a laminated dolomudstone (Photo C). Inter-crystalline and vuggy porosity are predominant and can best be seen in the thin section photograph (Photo D).

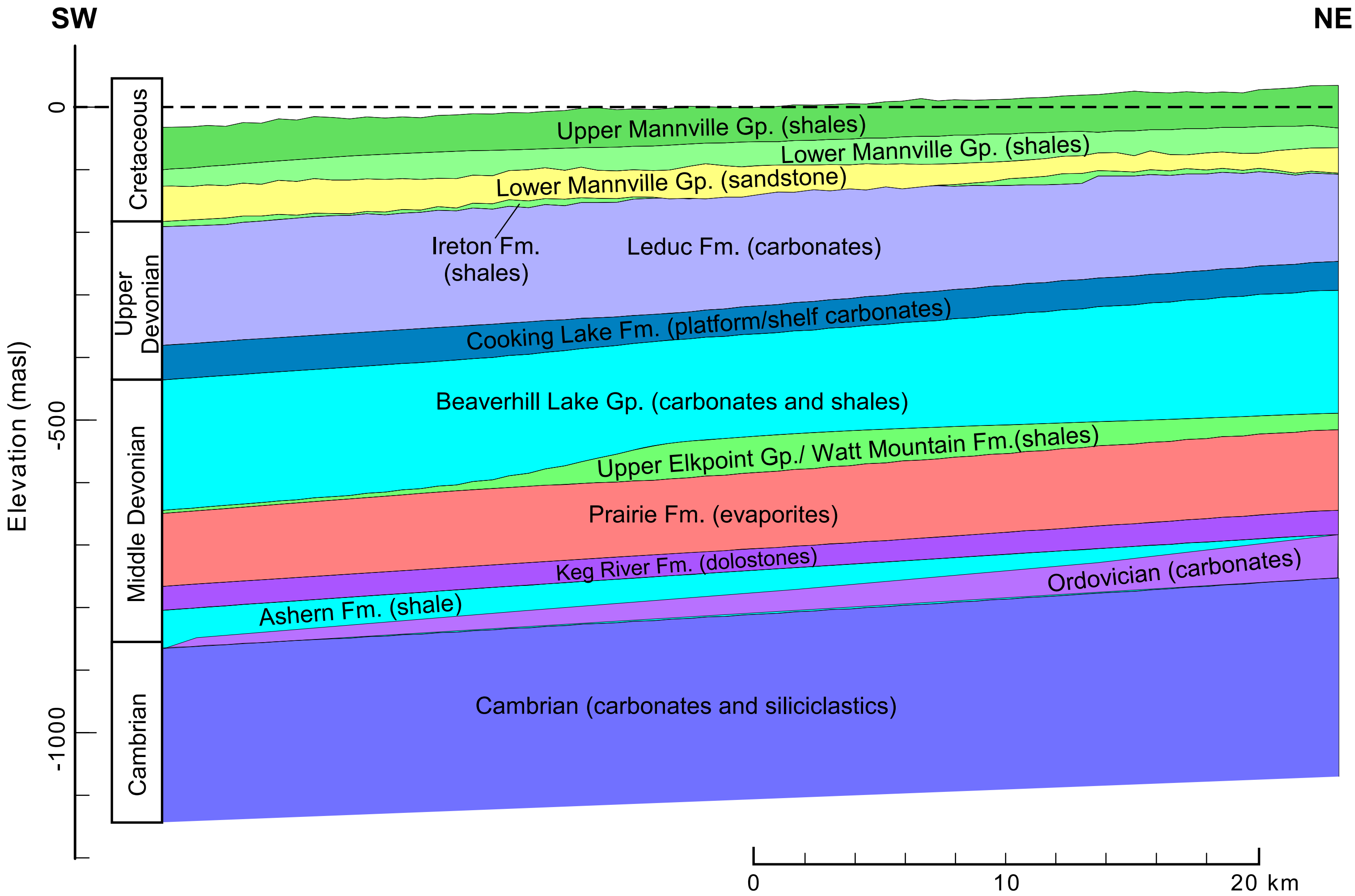


Figure 49. Schematic cross-section through the Provost Keg River injection area showing the Keg River aquifer, which is capped by a sequence of evaporites of the Prairie Formation.

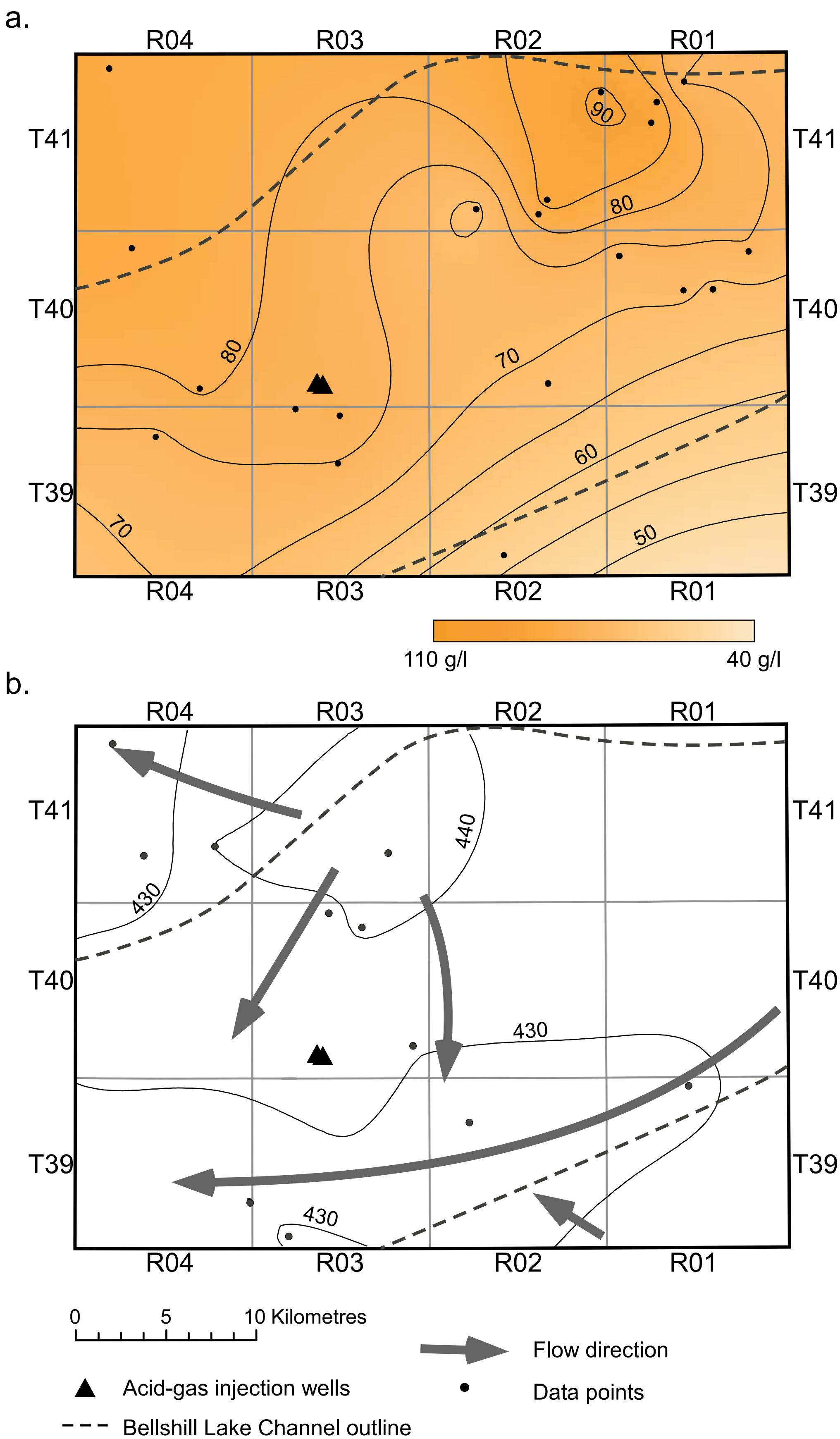
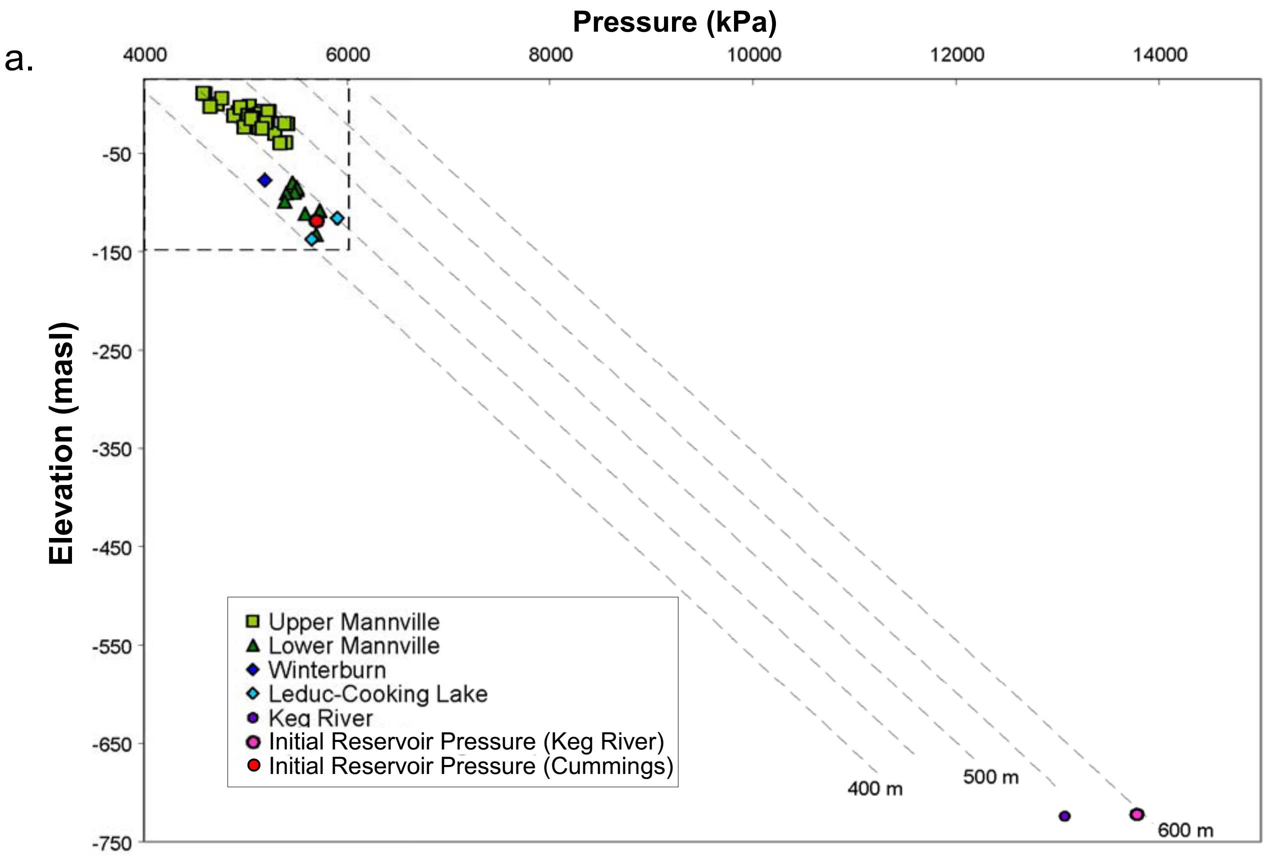


Figure 50. Distribution of: a) salinity (g/l) and b) hydraulic heads (m) with inferred flow directions of formation water in the Lower Mannville aquifer in the Hansman Lake local-scale study area. The location of the injection wells is also shown. Contour intervals are 5 g/l and 10 metres, respectively.



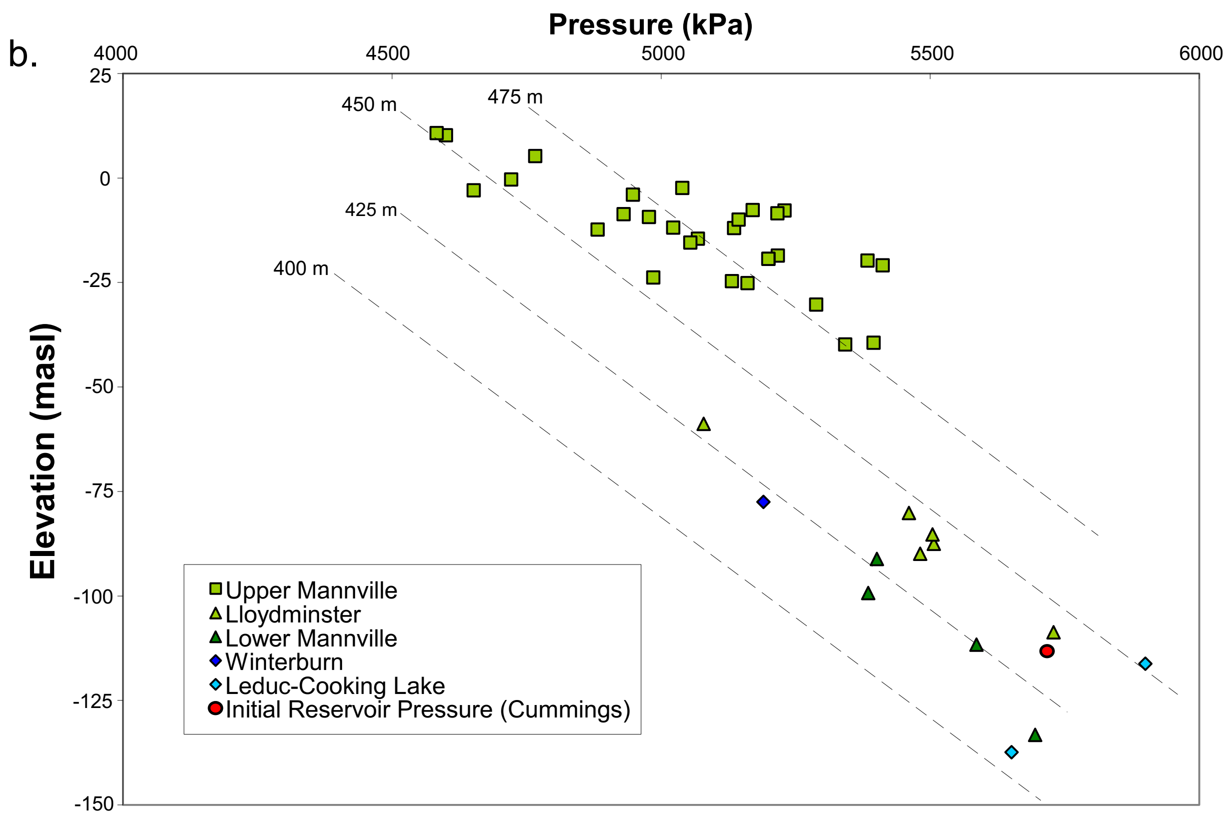


Figure 51. Distribution of pressure versus elevation in the Hansman Lake area showing: a) data from the Upper Mannville to the Keg River aquifers, including pressures from both the Hansman Lake Cummings and the Provost Keg River injection sites, and b) a more detailed view of pressure data from the Upper Mannville to Cooking Lake strata. The dashed lines delineate pressure-elevation trends with equal hydraulic-head values and the potential for vertical flow may be inferred perpendicular to those lines from high to low values.

Table 8. Major ion chemistry of Lower Mannville and Keg River brines in the Hansman Lake area (concentrations in g/l). * indicates analysis from the acid-gas injection well.

	Na	K	Ca	Mg	Cl	SO_4	HCO_3	TDS
Lower Mannville								
01-28-039-03-W-4	26.6	0.8	1.5	0.9	45.5	0.03	1.3	75.2
12-34-039-03-W-4	28.5	0.8	1.5	1.0	48.9	0.01	0.7	80.2
16-28-039-04-W-4	25.6	1.0	1.7	0.9	44.2	0.02	1.2	72.9
15-21-040-01-W-4	26.0		1.5	0.8	44.3	0.07	1.3	73.2
15-22-040-01-W-4	23.6	0.7	1.2	0.7	40.0	0.19	0.9	66.1
01-35-040-01-W-4	26.9	0.0	1.6	0.9	46.2	0.27	1.3	76.5
10-20-041-01-W-4	32.3	0.9	1.9	1.0	55.7	0.25	0.3	91.3
08-29-041-01-W-4	32.0	0.9	1.8	1.1	55.5	0.02	0.1	90.4
08-03-041-02-W-4	29.2	0.9	1.8	0.7	49.6	0.02	1.2	81.9
10-05-041-02-W-4	22.3		1.5	0.7	38.3	0.12	1.2	63.4
10-05-041-02-W-4	22.3		1.5	0.7	38.3	0.12	1.2	63.4
09-25-041-02-W-4	32.2	1.1	2.2	1.1	56.0	0.01	1.2	92.1
05-33-040-04-W-4	28.7	0.7	2.4	1.2	51.5	0.02	0.7	84.2
15-32-039-03-W-4	26.8	0.9	1.5	0.9	45.6	0.03	1.3	75.4
03-31-040-01-W-4	25.3	0.5	1.3	0.6	42.4	0.11	0.9	70.1
15-28-041-01-W-4	23.9	0.8	1.9	0.8	42.0	0.03	0.6	68.8
13-02-041-02-W-4	33.4	0.8	1.5	0.8	55.8	0.05	1.2	92.1
11-02-040-04-W-4	29.0	0.8	1.7	0.9	49.8	0.05	1.2	82.1
15-04-039-02-W-4	20.0	0.6	1.0	0.7	34.0	0.02	1.2	56.4
12-02-040-02-W-4	24.1	0.6	1.4	1.1	42.0	0.29	1.0	69.4
Minimum	20.0	0.5	1.0	0.6	34.0	0.01	0.1	56.4
Maximum	33.4	1.1	2.4	1.2	56.0	0.29	1.3	92.1
Average	26.9	0.8	1.6	0.9	46.3	0.09	1.0	76.2
Keg River								
08-14-040-03-W-4*	103.9	1.7	18.1	3.2	201.4	0.26	0.07	326.9
08-14-040-03-W-4*	106.9	2.2	22.0	2.5	207.3	0.35	0.13	341.4

Table 9. Well-scale porosity and permeability values obtained from measurements in core plugs from the Lloydminster (51 wells), Cummings (63 wells), and Dina (69 wells) formations, and permeability values calculated from 34 drillstem test analyses in the Hansman Lake area.

	Porosity (%)			Horiz. Perm. (mD)			Vert. Perm. (mD)			DST Perm. (mD)		
Formation	Min	Max	Avg	Min	Max	Median	Min	Max	Median	Min	Max	Median
Lloydminster	4	36	26	0.70	4080	696	48.00	3550	327			
Cummings	13	34	25	2.12	5280	582	0.12	2860	147	0.3	322	9
Dina	11	36	27	7.53	9880	1555	0.01	5120	331			

No data on rock properties exist for the Keg River Formation.

Flow of Formation Water

Formation water flow in the Lower Mannville aquifer is generally towards the west or southwest in the Hansman Lake area. The flow direction is sub-parallel to the long axis of the extent of the Bellshill Lake Valley channel sands, following the regional flow pattern. The horizontal hydraulic gradient at the Hansman Lake injection site is approximately 1 m/km. The relatively high salinity in the Lower Mannville aquifer (50 - 90 g/l) indicates that it is relatively isolated from dilution with meteoric recharge through the Colorado shales aquitard. However, salinity in the over- and underlying Upper Mannville and Leduc-Cooking Lake aquifers is in a similar range as the salinity in the Lower Mannville aquifer and the integrity of intervening aquitards is uncertain. The lithology in the entire Mannville Group is very variable, ranging from coarse-grained sandstones to shales, and no distinct laterally continuous aquitards could be identified. Still, separate grouping of data from the Upper and Lower Mannville aquifers in the pressure-versus-elevation plot indicates that there is a vertical hydraulic barrier between the two aquifers. On the other hand, pressure and corresponding hydraulic-head distributions in the Lower Mannville aquifer and underlying Leduc-Cooking Lake aquifer are in the same range and the intervening Ireton aquitard is thin in the Hansman Lake area, suggesting that there is hydraulic communication between the two aquifers.

The sparse hydrogeological data in the Keg River aquifer does not allow for an accurate characterization of formation water flow. According to the regional distribution of hydraulic head values and basin-scale flow interpretations, flow in the Keg River aquifer is updip, towards the northeast. The horizontal hydraulic gradient is approximately 0.5 m/km. A clear vertical hydraulic isolation of the Keg River aquifer is demonstrated by the significantly higher formation water salinity, hydraulic-head values and pressures (Figure 50) in the Keg River aquifer compared to overlying aquifers.

5.3 Kelsey

The Kelsey local-scale study area is defined around the Kelsey gas field and extends from 52.67°N to 52.93°N and 112.18°W to 112.76°W (Townships 43-45, Ranges 16-19W4) (Figure 10). Injection takes place in the Wabamun Group, a water-wet, non-producing unit, with sufficient porosity and permeability for injection. Production in the Kelsey Field is mainly from the overlying Glauconitic and Ellerslie formations in the Lower Mannville Group.

5.3.1 Geology

The carbonates of the Upper Devonian Wabamun Group range in thickness between 20 and 150 m within the local-scale study area and are on average 50 m thick in the injection area (Figure 52). The net pay is approximately 4 m. The thinning of the Wabamun Group towards the northeast results from the truncation of strata at the sub-Cretaceous unconformity. Within the study area, the sediments consist of alternating layers of coarse, sparry calcite and layers of anhedral calcite with stringers of very fine grained dusty dolomite, as well as anhydrite and bitumen filled fractures (Figure 53). The mainly fracture or inter-crystalline porosity varies widely in the Wabamun Group, ranging from very low to up to 13%.

The injection interval in the Wabamun Group is overlain by up to 100 m thick sandstones of the Lower Mannville Group (Figure 54). The operator of the Kelsey acid-gas injection site identified tight limestones in the upper part of the Wabamun Group as the top seal. However, these zones are thin and discontinuous, and it is likely that the sediments of the Wabamun and Lower Mannville Groups are in hydraulic communication on a local to regional scale. Therefore, the

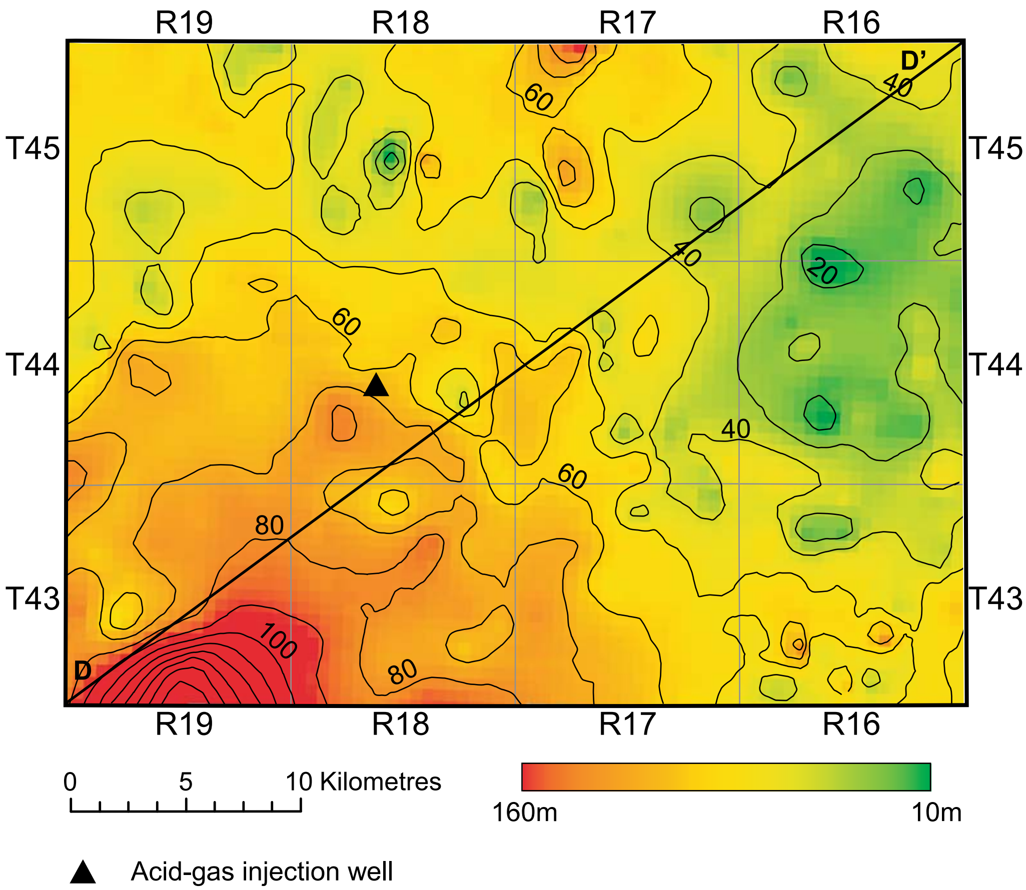


Figure 52. Isopach map of the Wabamun Group in the Kelsey local-scale study area. The location of the injection well is also shown. Contour interval = 10 metres. Cross-section D-D' is shown in Figure 54.

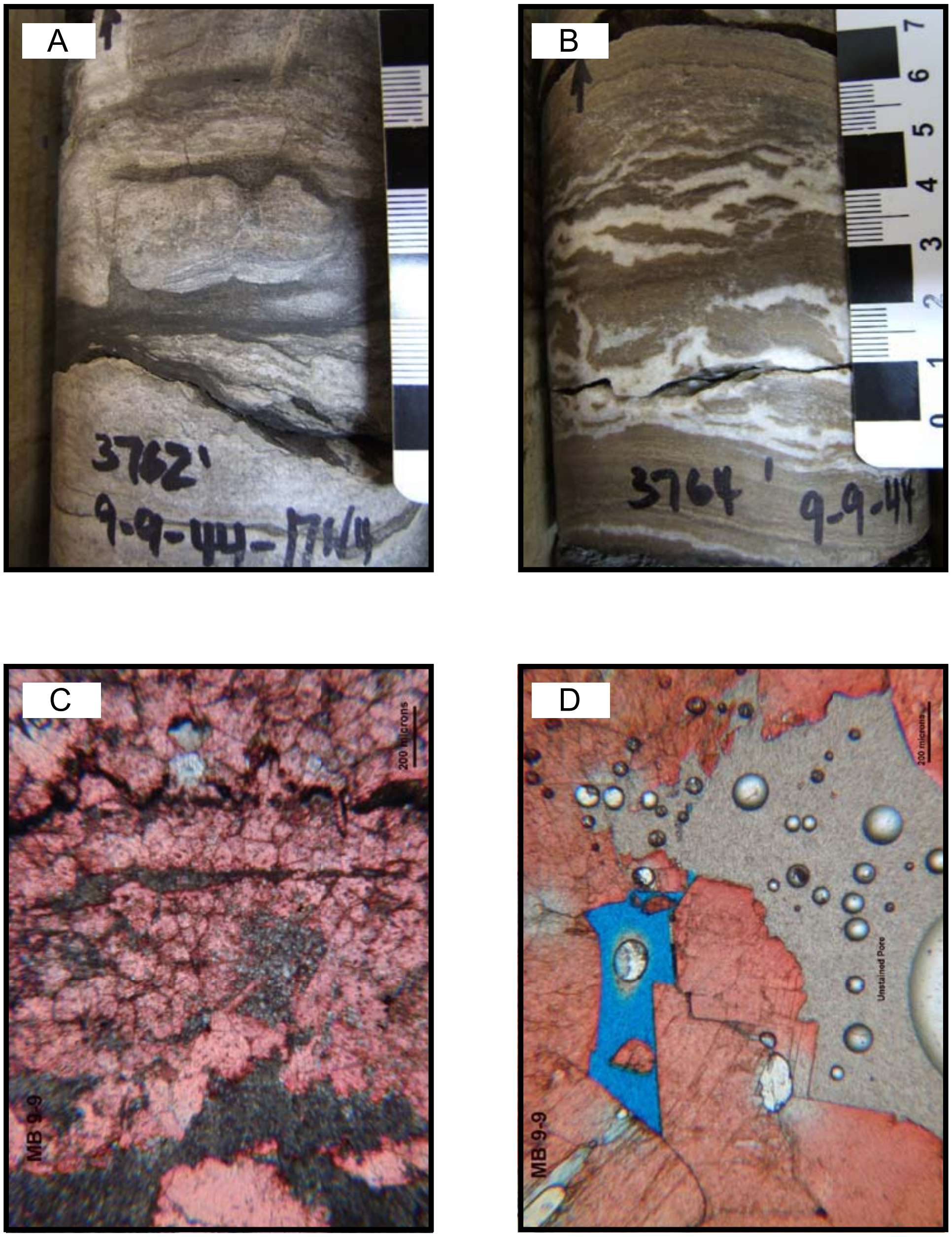


Figure 53. Core and thin section photographs of the Wabamun Group in the Kelsey area. Wavy, laminated limemudstones (Photo A) change to interlayered to laminated anhydrite/dolomitic limestone (Photo B). The thin section shows alternating layers of coarse, sparry calcite and layers of anhedral calcite with stringers of very fine grained dusty dolomite (Photo C). Inter-crystalline and vuggy porosity are predominant and can best be seen in the thin section photograph (Photos C and D).

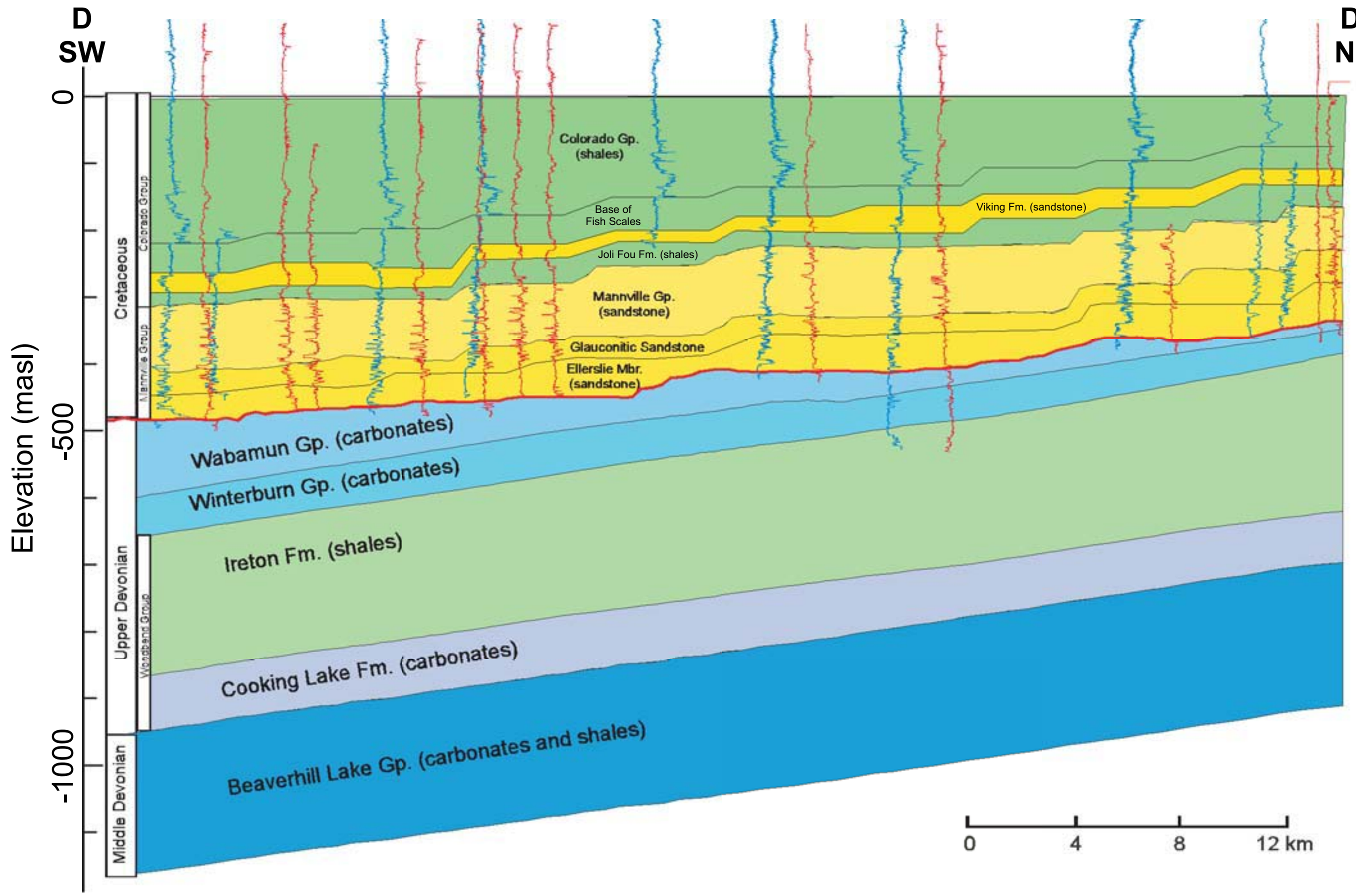


Figure 54. Local-scale cross-section through the Kelsey-Wabamun injection area. The Wabamun is unconformably (indicated by the red line) overlain by Cretaceous sandstones, before the aquifer system is capped by thick package of Colorado shales. The location of the cross-section is shown in Figure 52.

more than 100 m thick siltstones and shales of the Upper Mannville Group should be considered as the actual confining unit for the injection horizon (Figure 54). The Wabamun Group is underlain by the Upper Devonian Winterburn Group, which consists of siltstones and carbonates with a total thickness of more than 60 m.

5.3.2 Hydrogeological Characteristics and Rock Properties

Very few hydrogeological data exist for the Wabamun Group in the Kelsey area, because the petroleum industry has focused mainly on hydrocarbon occurrences in the overlying stratigraphic succession. However, the regional hydrogeological analysis indicated a weak or non-existing hydraulic separation of the Wabamun and Lower Mannville aquifers due to the lack of an effective intervening aquitard in the Kelsey area. Therefore, in the following the Wabamun and Lower Mannville will be considered as a combined aquifer.

Chemistry of Formation Waters

The major constituents of Wabamun-Lower Mannville formation water as determined from 57 analyses are sodium (30 g/l) and chloride (55 g/l), making up 94% of the total dissolved solids (Table 10). Magnesium, calcium, sulphate and bicarbonate are present in minor concentrations (Figure 41c). In the Kelsey area, formation water chemistry is relatively invariable, salinity ranging from approximately 70 g/l in the southwest and southeast to 100 g/l in the center and northeast (Figure 55a). The average in-situ density of formation water in the Permo-Carboniferous aquifer in the local-scale study area was estimated to be 1061 kg/m^3 using the methods presented in Adams and Bachu (2002).

Table 10. Major ion chemistry of Lower Mannville-Wabamun brines in the Kelsey area (concentrations in g/l).

	Na	K	Ca	Mg	Cl	SO_4	HCO_3	TDS
Lower Mannville								
Minimum	22.9	0.04	1.5	0.6	43.3	0.01	0.1	70.9
Maximum	35.1	1.6	5.8	1.9	64.5	0.5	1.5	105.3
Average	29.8	0.8	3.3	1.1	54.6	0.17	0.7	89.4
Wabamun								
13-11-044-17-W-4	36.9		7.1	1.3	72.0	1.48	0.3	118.9
01-26-043-17-W-4	23.6		4.0	2.2	49.0	0.55	0.9	79.8

Pressure Regime

Hydraulic heads, calculated with a reference density of 1060 kg/m^3, decrease from about 450 m in the south to less than 370 m in the northwestern part of the area (Figure 55b). A relative high of hydraulic-head values of above 390 m extends from the south to the centre of the study area. The contour pattern indicates northwestward-channelled flow of formation water in the western half of the study area, having a very low hydraulic gradient in the vicinity of the Kelsey acid-gas injection site. In the eastern half of the Kelsey area flow is towards the east.

Plotting pressure values versus elevation (Figure 56) shows that data from the Lower Mannville and Wabamun aquifers fall within the same range (350 to 450 m equivalent hydraulic head), corroborating the good hydraulic interconnectivity between the two aquifers and the absence of an intervening aquitard. Data from the Winterburn aquifers follows a similar trend, indicating well-established pressure continuity within the entire Lower Mannville-Winterburn succession.

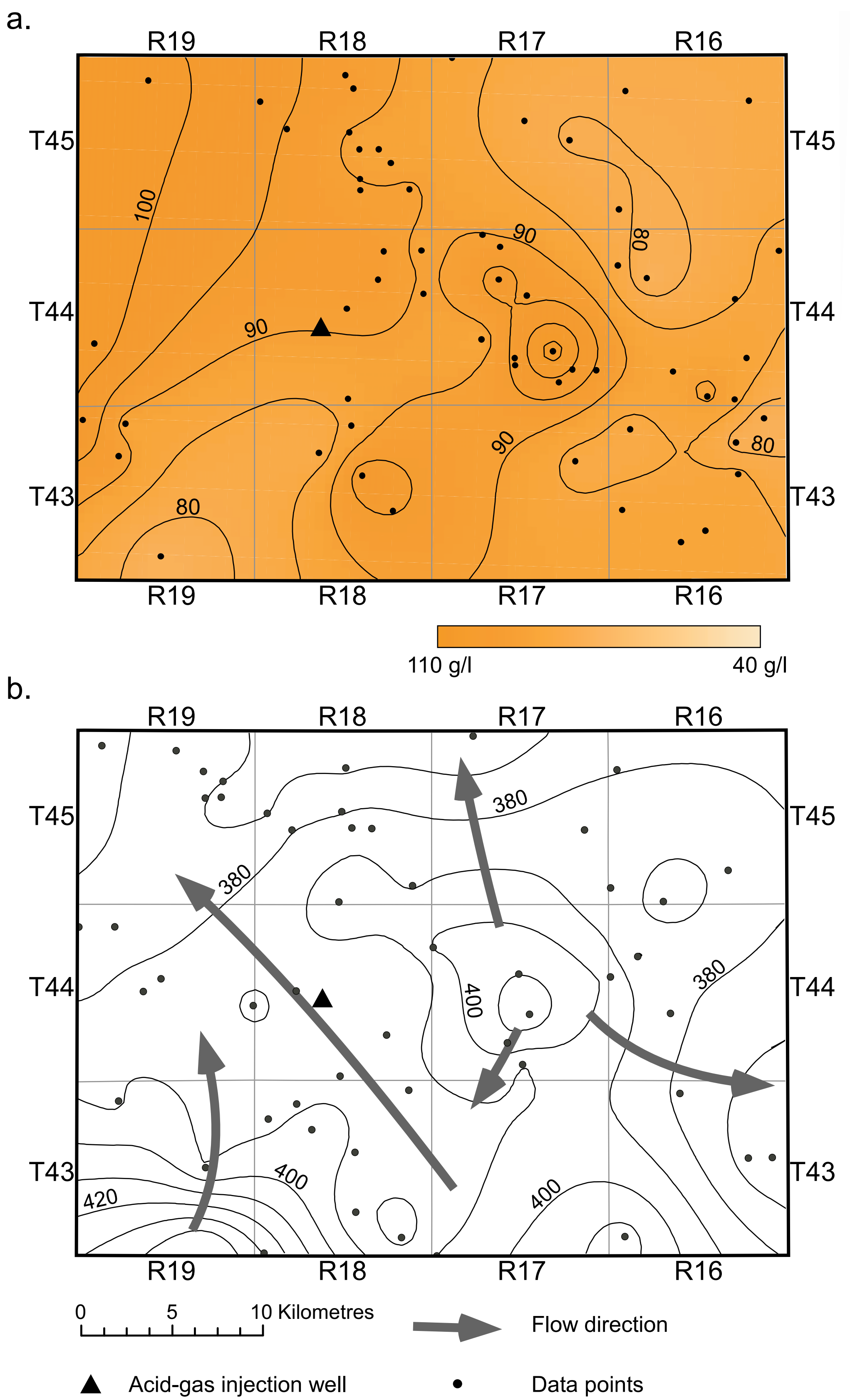
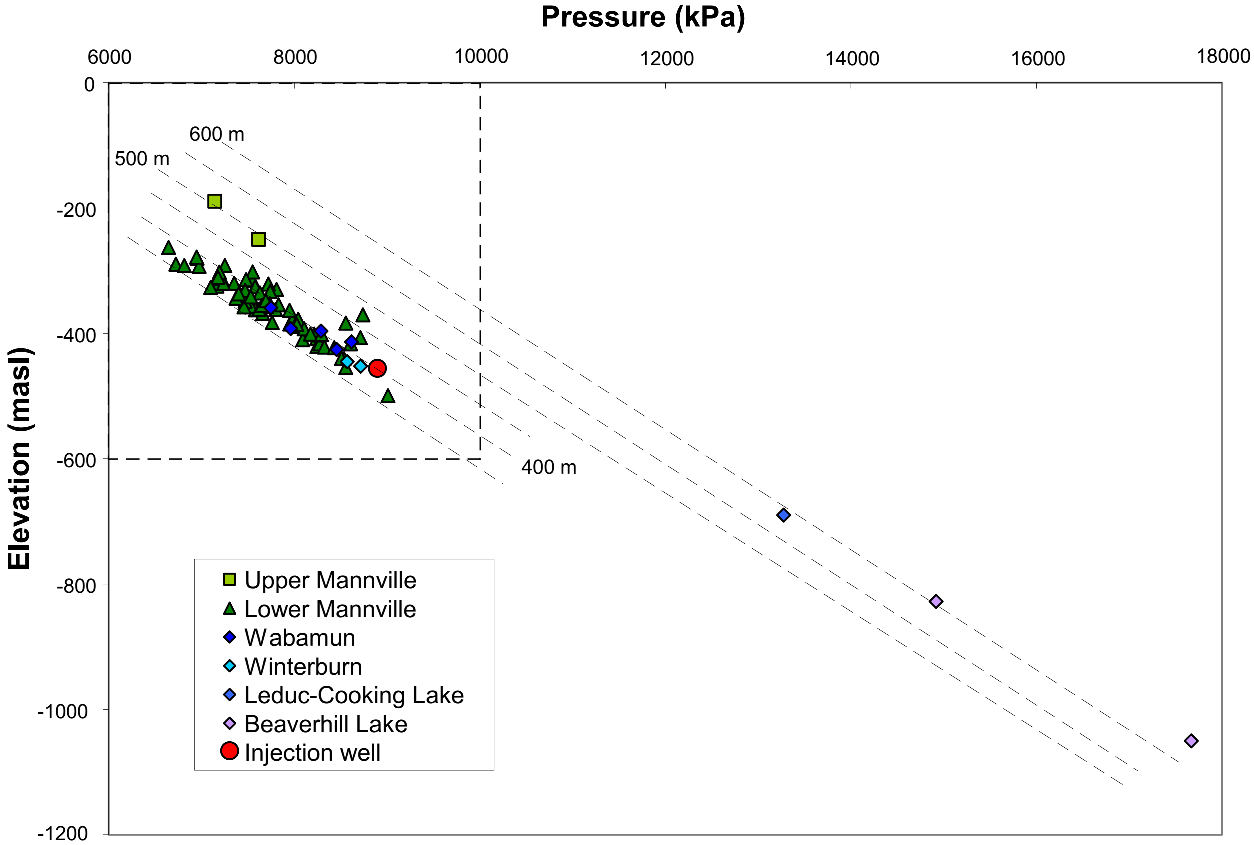


Figure 55. Distribution of: a) salinity (g/l) and b) hydraulic heads (m) with inferred flow direction of formation water in the Wabamun-Lower Mannville aquifer in the Kelsey local-scale study area. The location of the injection well is also shown. Contour intervals are 5 g/l and 10 metres, respectively.

a.



b.

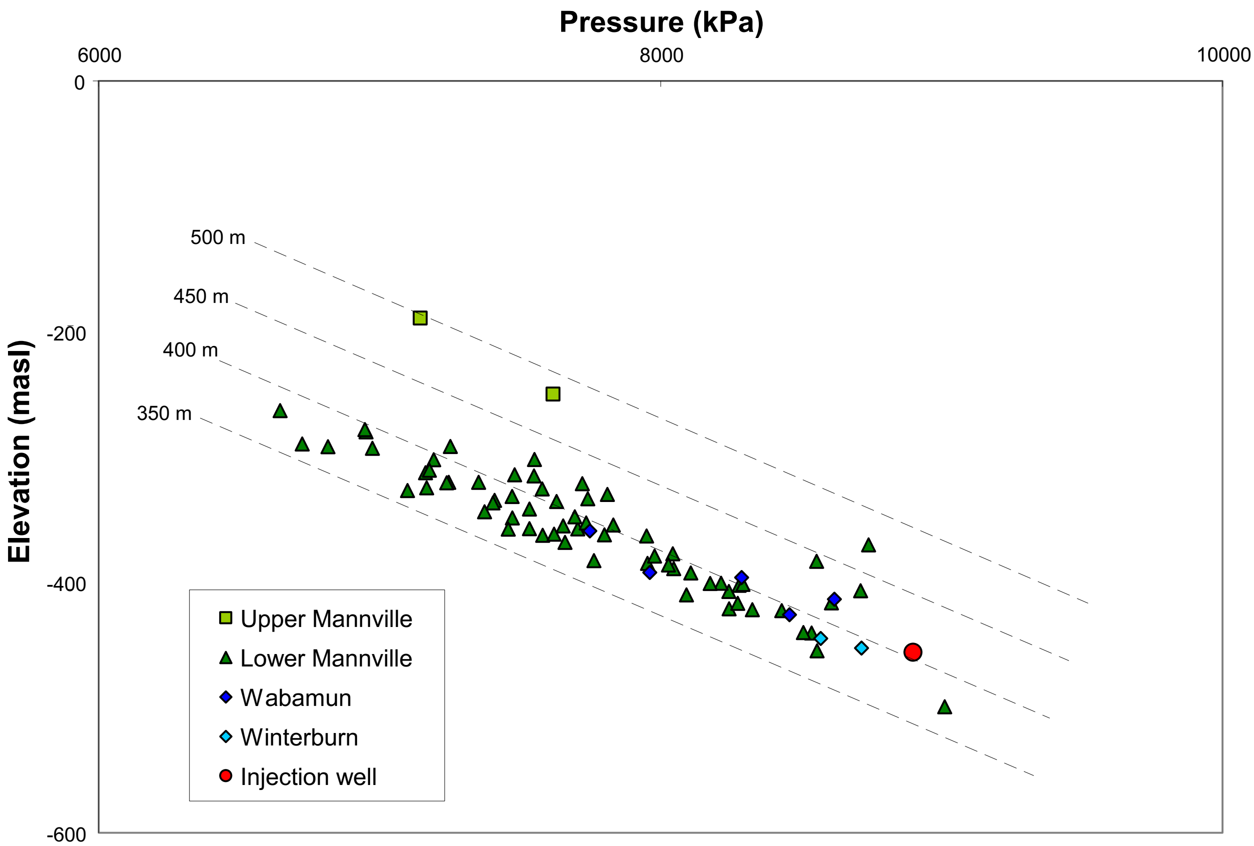


Figure 56. Distribution of pressure versus elevation in the Kelsey area showing: a) data from the Upper Mannville to the Keg River aquifers, and b) a more detailed view of pressure data from the Upper Mannville to Winterburn strata. The dashed lines delineate pressure-elevation trends with equal hydraulic-head values and the potential for vertical flow may be inferred perpendicular to those lines from high to low values.

In comparison, the pressure-elevation trend in the overlying Upper Mannville aquifer is offset towards higher equivalent hydraulic head values (~500 m), indicating weak cross-formational communication between the Upper Mannville aquifer and the Lower Mannville-Winterburn aquifer system and a downward vertical hydraulic gradient. The pressure data from the deeper Leduc-Cooking Lake and Beaverhill Lake aquifers also plot along a trend that is representative of a higher hydraulic head value (~600 m) than that in the Lower Mannville-Winterburn succession, which results in an upward hydraulic gradient. However, the distinct offset of the two pressure regimes suggests that the intervening Ireton aquitard prevents cross-formational flow from the Leduc-Cooking Lake aquifer into the Winterburn aquifer in the Kelsey area.

Rock Properties

The average of well-scale porosity and permeability values for the injection horizon, the Wabamun Group, and the overlying Lower Mannville Group are shown in Table 11. Also shown are permeability values calculated from drillstem tests that were performed in the Wabamun and Lower Mannville aquifers, values ranging between 0.2 and 3920 mD with a median of approximately 5 mD and 11 mD, respectively. Core plug measurements generally are biased toward higher porosity and permeability values. The average values of porosity (21%), horizontal permeability (179 mD) and vertical permeability (573 mD) in the Lower Mannville Group are noticeably higher than respective values in the injection horizon, the Wabamun Group. Core data from the Wabamun are sparse (2 wells) and appear to originate from zones in the Wabamun with relatively low porosity and permeability in the upper part of the formation.

Table 11. Well-scale porosity and permeability values obtained from measurements in core plugs from the Lower Mannville (13 wells) and Wabamun (2 wells) groups, and permeability values calculated from 52 drillstem test analyses in the Kelsey area.

	Porosity (%)			Horiz. Perm. (mD)			Vert. Perm. (mD)			DST Perm. (mD)		
Formation	Min	Max	Avg	Min	Max	Median	Min	Max	Median	Min	Max	Median
Ellerslie	0.16	0.25	21	5.53	3630	179	28.60	2220	573	0.16	3920	11.1
Wabamun			4			129			19	0.80	61	4.9

Flow of Formation Water

Due to the absence of the Lower Banff-Exshaw aquitard along the pre-Cretaceous erosional unconformity in the Kelsey area the Lower Mannville, the Wabamun Group and possibly also the Winterburn Group together form a contiguous aquifer. Flow for formation water is towards the northwest in the western half of the study area where the Kelsey acid-gas injection site is located. The horizontal hydraulic gradient at the Kelsey injection site is approximately 0.5 m/km. The distribution of formation water pressure with depth and hydraulic head values in the various aquifers confirm the existence of effective barriers to cross-formational flow between the Lower Mannville-Winterburn succession and adjacent aquifers in the form of the Ireton aquitard and fine-grained sediments of the Upper Mannville Group.

5.4 Galahad

The Galahad local-scale study area is defined around the Galahad gas field and extends from 52.40°N to 52.67°N and 111.59°W to 112.16°W (Townships 40-42, Ranges 12-15W4) (Figure 10). Injection takes place in the Leduc Formation of the Upper Devonian Woodbend Group. Production in the Galahad Field is mainly from the Ellerslie Member in the Lower Mannville Group and from the Camrose Member in the uppermost part of the Woodbend Group.

5.4.1 Geology

In the local-scale study area, the carbonates of the Upper Devonian Leduc Formation range in thickness between 180 and 240 m and are on average 220 m thick in the injection area (Figure 57a). The net pay given by the operator is 8 m. Within the study area, the sediments consist of grey to brown, crystalline dolomite. The dolostone is composed of anhedral, interlocking crystals of massive dolomite with sizes between 50 and 100 µm (Figure 58). The Galahad injection site is located on the crest of the Killam Barrier Reef, which indicates that the rocks were deposited in a shallow-marine environment with moderately agitated water energy. There is an abundance of vuggy porosity in the Leduc Formation, porosity values reaching up to 30%.

The Leduc injection interval is overlain by up to 40 m of shale of the Ireton Formation, which thickens considerably to the west towards the center of the East Shale Basin (Figure 57b). The Leduc Formation is underlain by the Upper Devonian Cooking Lake Formation, which consists of mostly tight limestones, which are more than 100 m thick, and by shaly limestones of the Beaverhill Lake Group.

5.4.2 Hydrogeological Characteristics and Rock Properties

Chemistry of Formation Waters

The major constituents of Leduc-Cooking Lake formation water as determined from 9 analyses are sodium (28.4 g/l) and chloride (56.5 g/l), making up approximately 92% of the total dissolved solids (Table 12). Magnesium, calcium, sulphate and bicarbonate are present in minor concentrations (Figure 59a).

In the Galahad area, chemical analyses of Leduc-Cooking Lake formation water are restricted to the area in and east of the Killam Barrier Reef. The salinity increases slightly from approximately 75 g/l in the southeast to 100 g/l in the west (Figure 60a). The average in-situ density of formation water in the Leduc-Cooking Lake aquifer was estimated to be 1064 kg/m^3, using the methods presented in Adams and Bachu (2002).

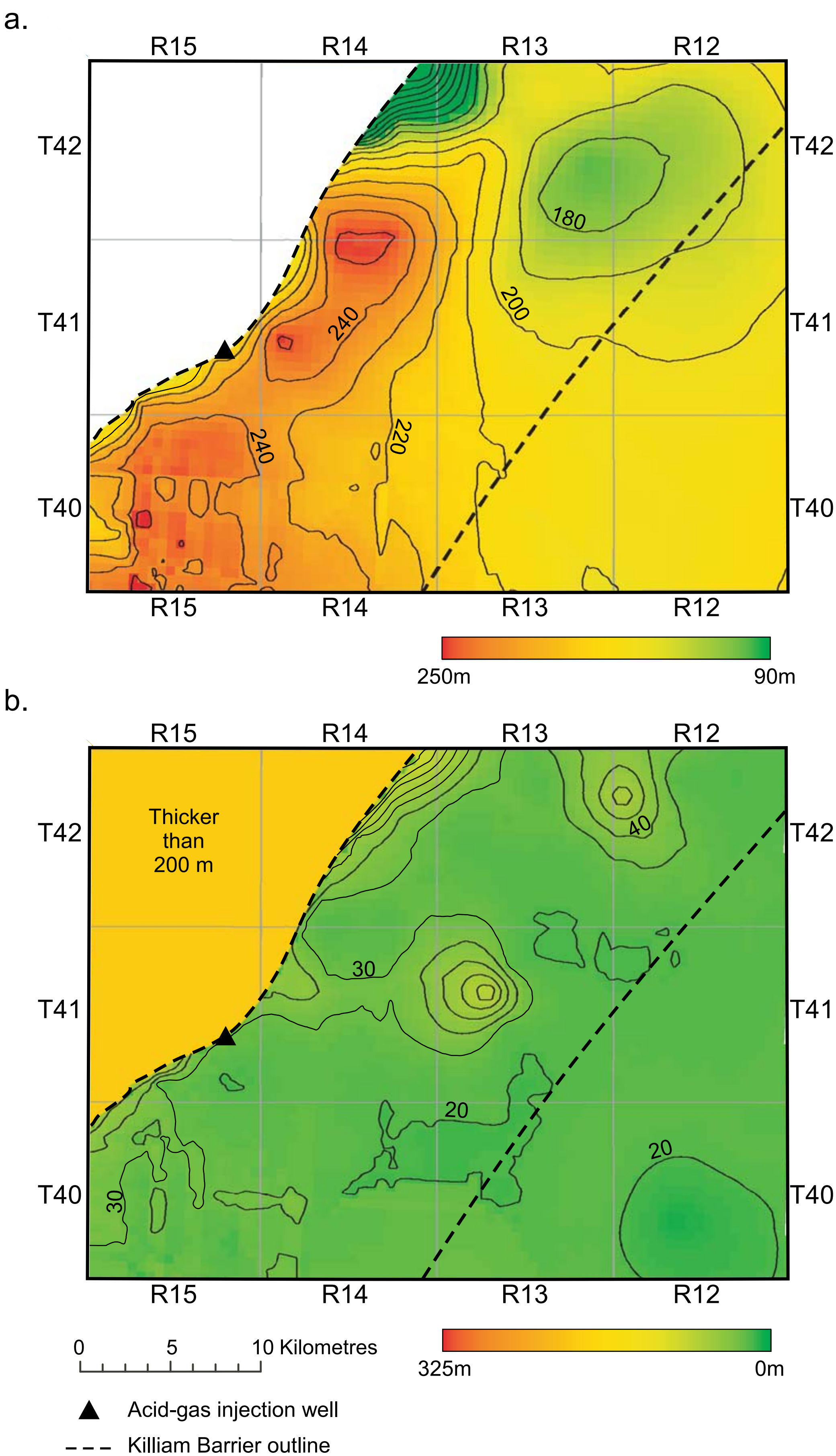


Figure 57. Isopach maps in the Galahad local-scale study area: a) Leduc Formation and b) Ireton Formation. The location of the injection well is also shown. Contour interval = 10 metres.

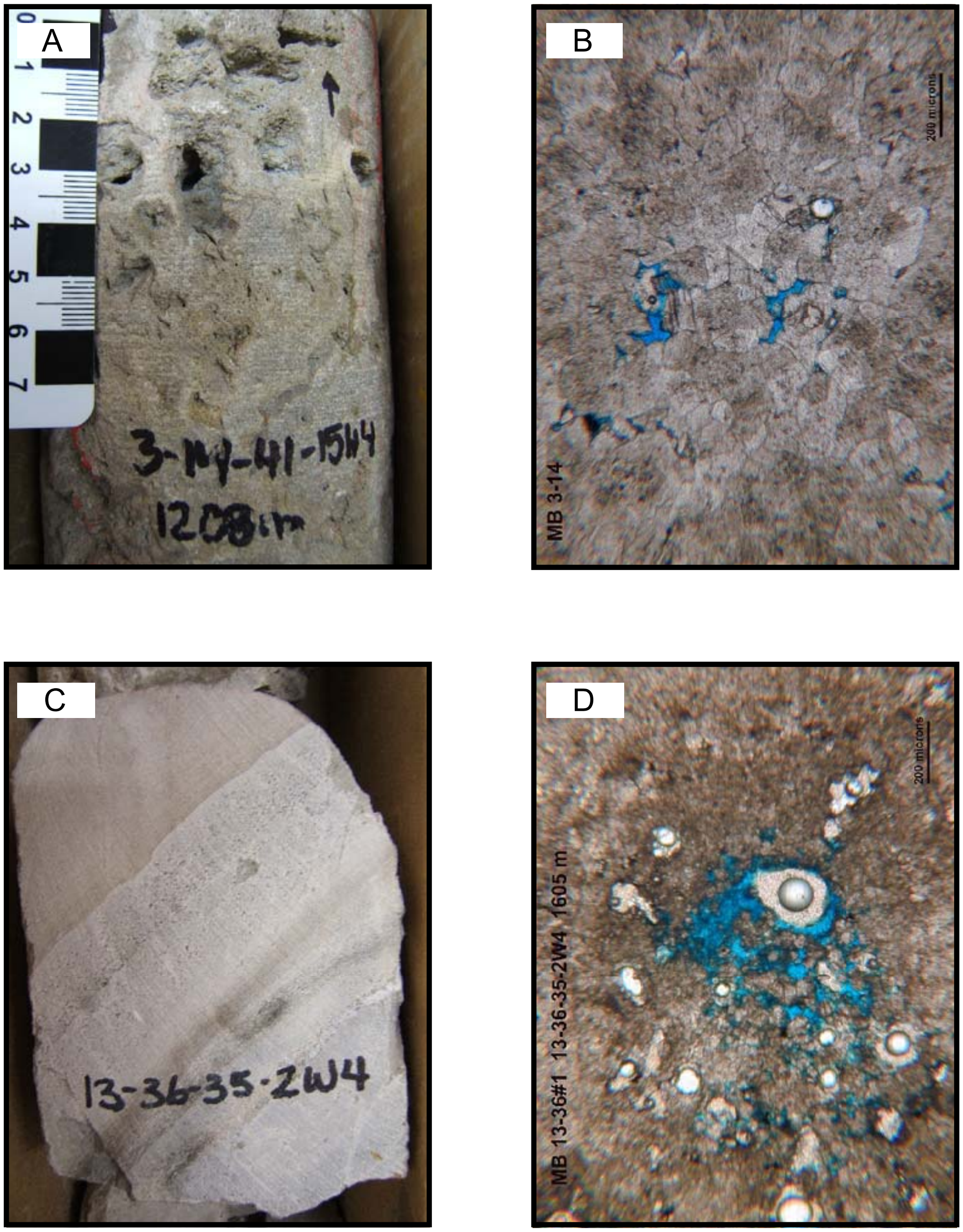


Figure 58. Core and thin section photographs of the Leduc Formation in the Galahad (Photos A & B) and Thompson Lake areas (Photo C & D). Fossiliferous, vuggy dolostones (Photo A) indicate the reefal environment in the Galahad area, whereas the laminated dolostone in the Thompson Lake area (Photo C) is representative of a shallow marine, more restricted environment. Inter-crystalline and vuggy porosity are predominant and can best be seen in the thin section photographs (Photos B & D).

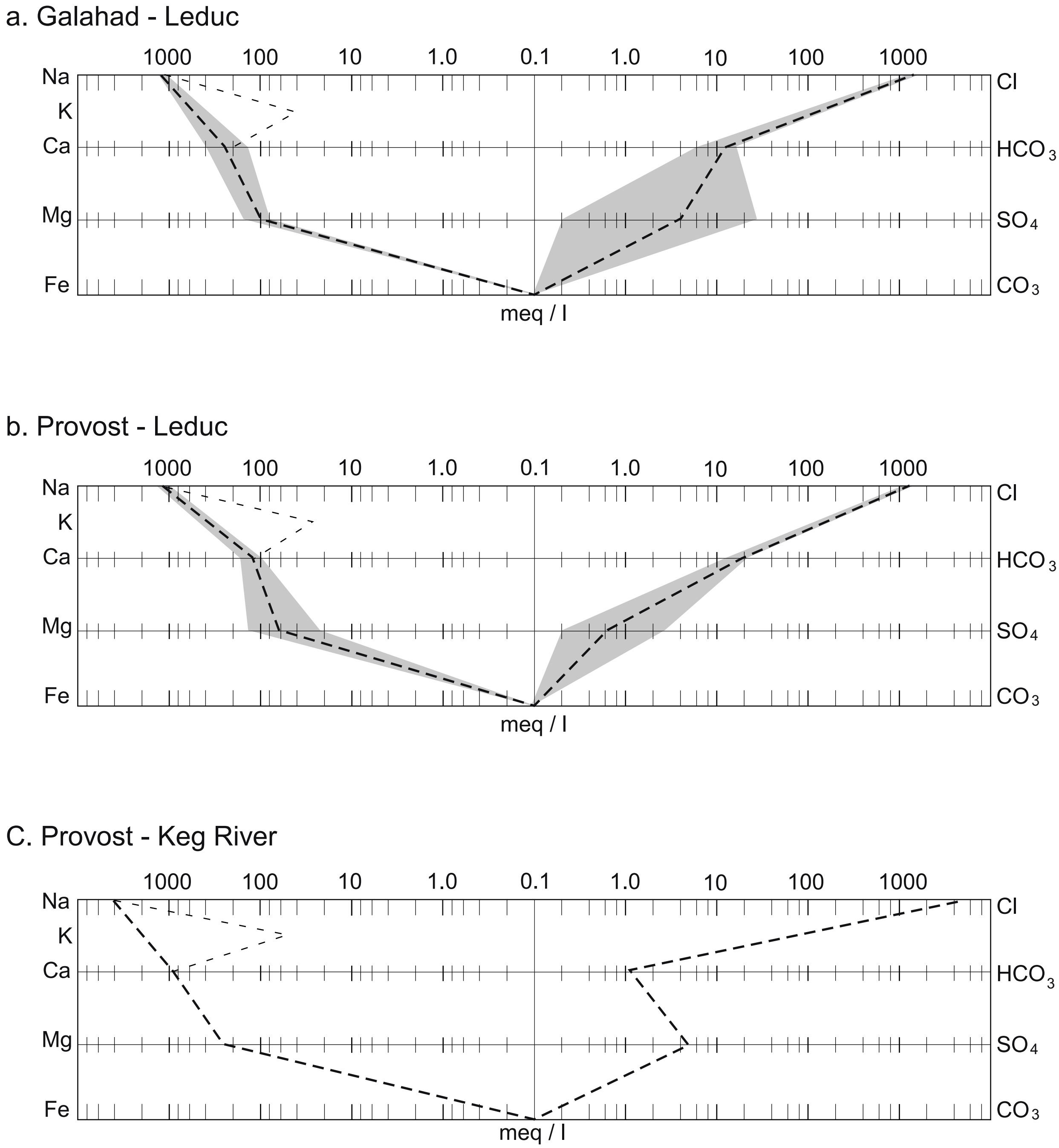


Figure 59. Stiff diagrams of Paleozoic formation waters in the: a) Galahad area (Leduc-Cooking Lake aquifer, 10 analyses), b) Thompson Lake area (Leduc-Cooking Lake aquifer, 9 analyses) area and c) Hansman Lake area (Keg River aquifer, 1 analysis). The grey-shaded area shows the range, the bold dashed line represents the average concentrations in meq/l (milliequivalents per litre) and the thin dashed line represents the potassium concentration.

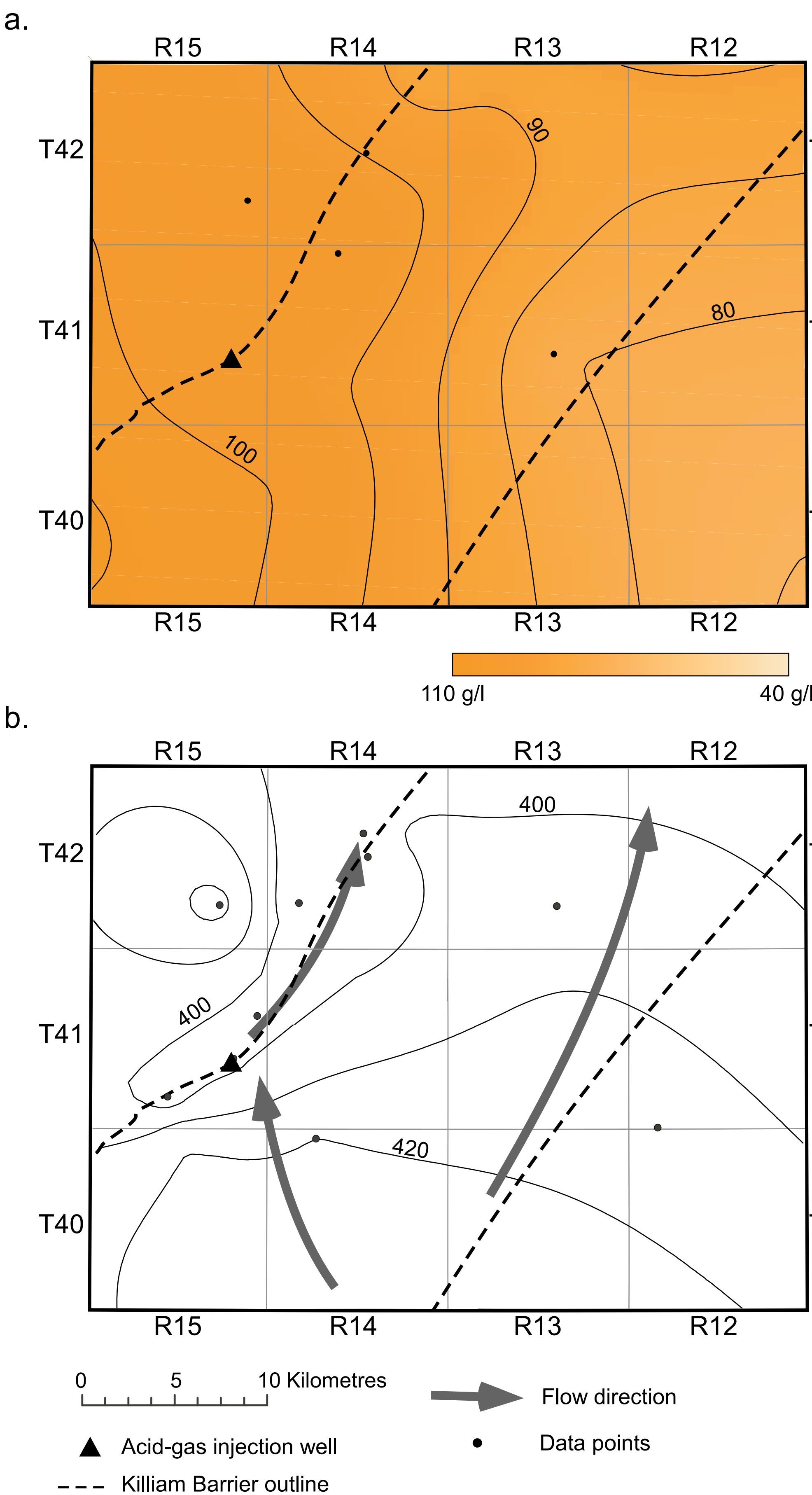


Figure 60. Distribution of: a) salinity (g/l) and b) hydraulic heads (m) with inferred flow direction of formation water in the Leduc-Cooking Lake aquifer in the Galahad local-scale study area. The location of the injection well is also shown. Contour intervals are 5 g/l and 10 metres, respectively.

Table 12. Major ion chemistry of brines from the Leduc-Cooking Lake aquifer in the Galahad area (concentrations in g/l). * indicates analysis from the acid-gas injection well.

	Na	K	Ca	Mg	Cl	SO_4	HCO_3	TDS
04-09-041-14-W-4	31.4		3.9	1.1	58.0	0.2	0.8	95.0
11-33-041-14-W-4	33.3		4.8	1.1	62.5	0.05	0.6	102.0
07-10-042-13-W-4	28.1		3.9	1.4	53.6	0.01	0.9	87.4
14-17-042-13-W-4	32.1		3.8	1.4	60.0	0.03	0.4	97.5
10-27-042-13-W-4	26.3		4.2	1.8	52.7	0.1	0.9	85.5
07-15-041-13-W-4	24.3	0.9	3.2	1.0	48.4	0.04	1.0	78.9
10-36-042-14-W-4	24.1		5.1	2.1	50.6	1.6	0.5	83.8
07-29-040-14-W-4	27.7		7.6	2.3	61.0	1.4	1.1	100.5
15-04-041-15-W-4	28.1	1.7	8.0	1.4	60.0	1.0	1.0	98.9
01-14-041-15-W-4*	27.4	1.5	6.0	0.9	58.4	1.1	0.5	95.9
Average	28.3	1.3	5.0	1.4	56.5	0.6	0.8	92.5

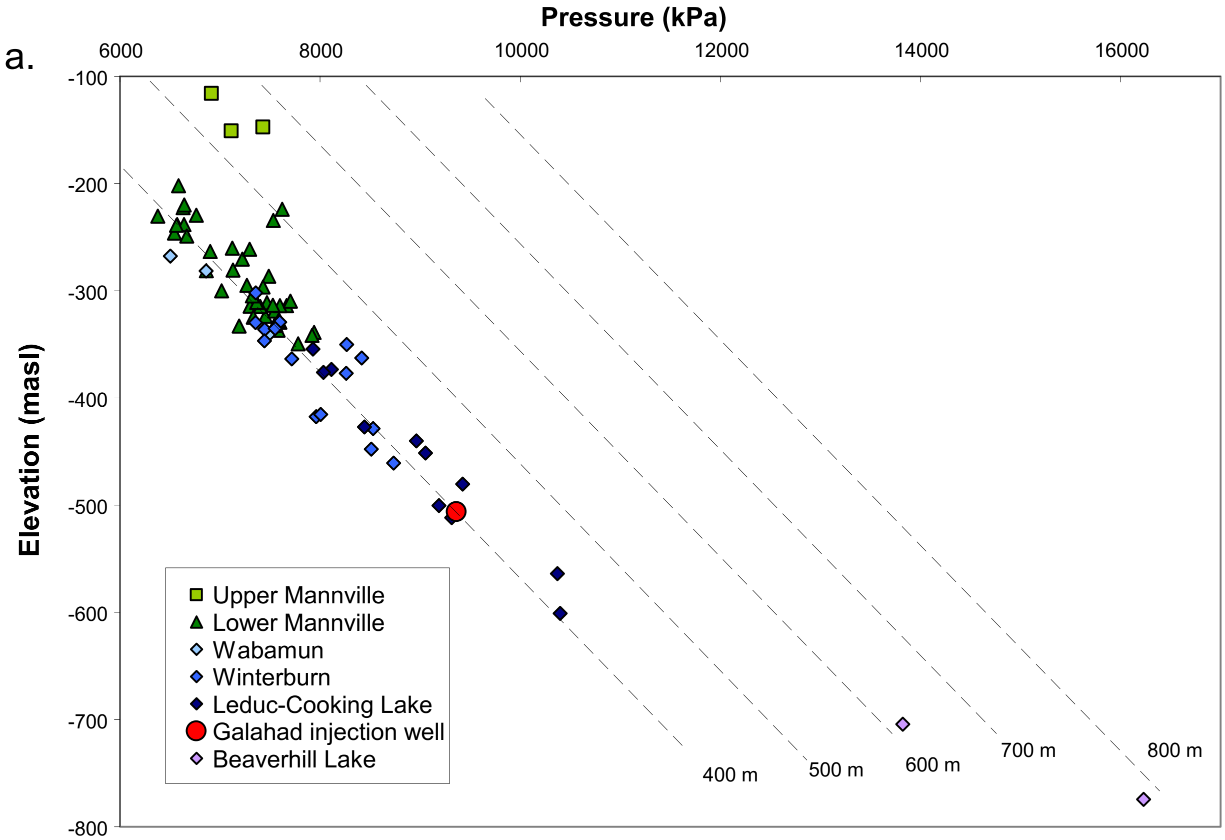
Pressure Regime

There is no production from the Leduc Formation in the Galahad area, and existing pressure tests are limited to the northwestern half of the study area, mainly performed in the Killam Barrier Reef. Hydraulic-head values decrease southward from 420 m to 380 m (Figure 60b), inferring northward-directed flow of formation water. Flow appears to be focused into an area of hydraulic low (< 400 m) in the vicinity of the Galahad injection operation, which is located at the northwestern edge of the Killam Barrier Reef. Flow continues either northeastward, sub-parallel to the reef edge, or the possibility exists for cross-formational flow into the overlying Winterburn aquifer.

The distribution of pressure versus elevation shows a grouping of data from the Lower Mannville to Woodbend aquifers along a gradient that corresponds to 350 - 450 m hydraulic-head (Figure 61a), suggesting some degree of hydraulic communication between these aquifers. The exception are two data points from the southeastern part of the Lower Mannville aquifer (~ 500 m hydraulic head), which is explained by the weak lateral hydraulic connection between Lower Mannville channel sands and off-channel sediments (see Chapter 4.2.2). A more detailed graph of pressure data versus elevation in the vicinity of the Galahad injection site (Figure 61b) shows that there is the potential for upward cross-formational flow from the Leduc-Cooking Lake aquifer (425 m hydraulic head) into the Winterburn aquifer (< 400 m hydraulic head). In contrast, pressure data from the Upper Mannville and Beaverhill Lake aquifers plot along trends that correspond to notably higher hydraulic-head values (550 m and 600 - 800 m, respectively), which indicates that intervening aquitards, especially the Waterways aquitard, effectively retard cross-formational flow. The potential for vertical flow is downwards from the Upper Mannville into the Lower Mannville aquifer, and upwards from the Beaverhill Lake into the Leduc-Cooking Lake aquifer.

Rock Properties

The range and average of well-scale porosity and permeability values for the injection horizon, the Leduc Formation, and the overlying Ireton Formation are shown in Table 13. Porosity values for the Leduc and Ireton formations are very similar, averaging 12 and 10%, respectively. However, both median horizontal and vertical permeability values are more than a magnitude lower in the Ireton Formation (k_h = 10 mD, k_v = 2 mD) than in the Leduc Formation (k_h = 2005,



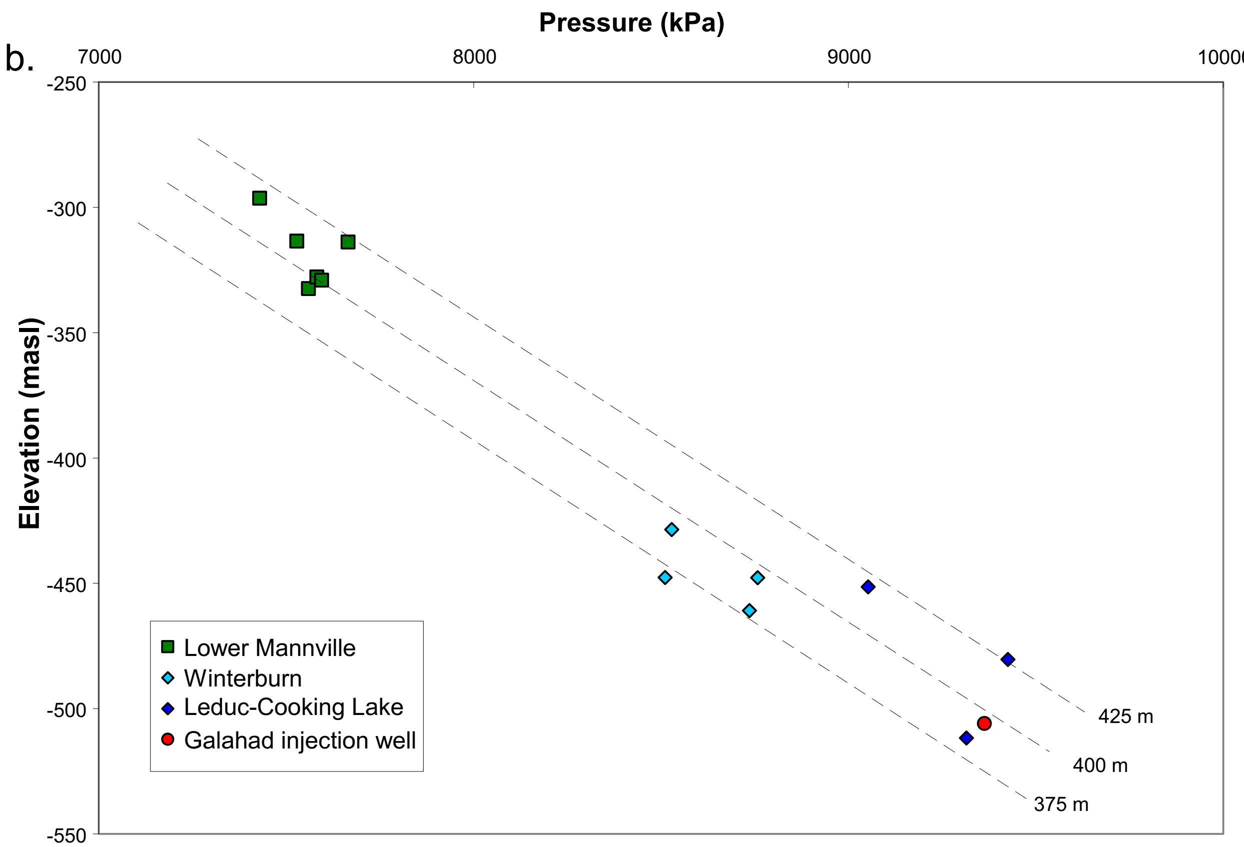


Figure 61. Distribution of pressure versus elevation in the injection strata and adjacent formations in: a) the entire Galahad local-scale study area and b) in a small area of within three sections of the acid-gas injection well. The dashed lines delineate pressure-elevation trends with equal hydraulic-head values and the potential for vertical flow may be inferred perpendicular to those lines from high to low values.

k_v = 40 mD), confirming the aquitard character of the former. Also shown are reservoir-scale permeability values calculated from drillstem tests that were performed in the Leduc-Cooking Lake aquifer. These values range over 4 orders of magnitude with a median permeability of 3 mD.

Table 13. Well-scale porosity and permeability values obtained from measurements in core plugs from the Leduc (23 wells) and Ireton (26 wells) formations in the Galahad area. Also shown are permeability values calculated from 8 drillstem test analyses performed in the Leduc Formation.

	Porosity (%)			Horiz. Perm. (mD)			Vert. Perm. (mD)			DST Perm. (mD)		
Formation	Min	Max	Avg	Min	Max	Median	Min	Max	Median	Min	Max	Median
Ireton	1	30	10	0.02	477	10	0.01	54	2			
Leduc/ Cooking Lake	3	26	12	0.47	1670	205	0.01	135	40	0.3	1417	3

Flow of Formation Water

Flow of formation water in the Leduc-Cooking Lake aquifer in the Galahad area is north-northeastward, sub-parallel to the extent of the Killam Barrier Reef. The horizontal hydraulic gradient in the vicinity of the Galahad injection site, which is located at the northwestern edge of the Killam Barrier Reef, is approximately 1 m/km. Pressure data show that an apparent separation of hydraulic regimes exists between the Lower Mannville-Woodbend succession and the overlying Upper Mannville aquifer and the underlying Beaverhill Lake aquifer. However, within the Lower Mannville-Woodbend succession similarities in both salinity and pressure data suggest the possibility of cross-formational hydraulic communication. In fact, there are no major aquitards in the Wabamun or Winterburn Groups, and the Ireton aquitard overlying the Killam Barrier Reef is relatively thin (10 to 40 m).

5.5 Thompson Lake (Provost-Leduc)

The Thompson Lake local-scale study area extends from 52.40°N to 52.67°N and 111.01°W to 111.58°W (Townships 40 to 42 and Ranges 8 to 11W4), directly bordering the Galahad area to the east (Figure 10). Acid gas is injected in the Leduc Formation of the Upper Devonian Woodbend Group. Saltwater is currently disposed of through wells in the Lower Mannville Glauconitic/Dina channel sandstones, which act as backup disposal zone for acid gas.

5.5.1 Geology

The carbonates of the Upper Devonian Leduc Formation in the Thompson Lake local-scale study area are about 270 m thick (Figure 62a) with a net pay given by the operator of 40 m. Within the study area, the sediments consist of dusty brown calcareous dolomite with anhedral grains smaller than 50 µm (Figure 58). The Thompson Lake injection site is located on the interior platform of the Southern Alberta Shelf (Figure 17), which indicates that the rocks were deposited in a shallow-marine environment and the presence of laminated anhydrite suggests periodically sabkha-like conditions. The porosity of the Leduc platform carbonates is generally inter-crystalline and less than 15%.

The Leduc injection interval is overlain by up to 20 m of shale of the Ireton Formation (Figure 62b), which together with the Winterburn Group aquitard form an effective seal. The Leduc Formation is underlain by the Upper Devonian Cooking Lake Formation, which consists of

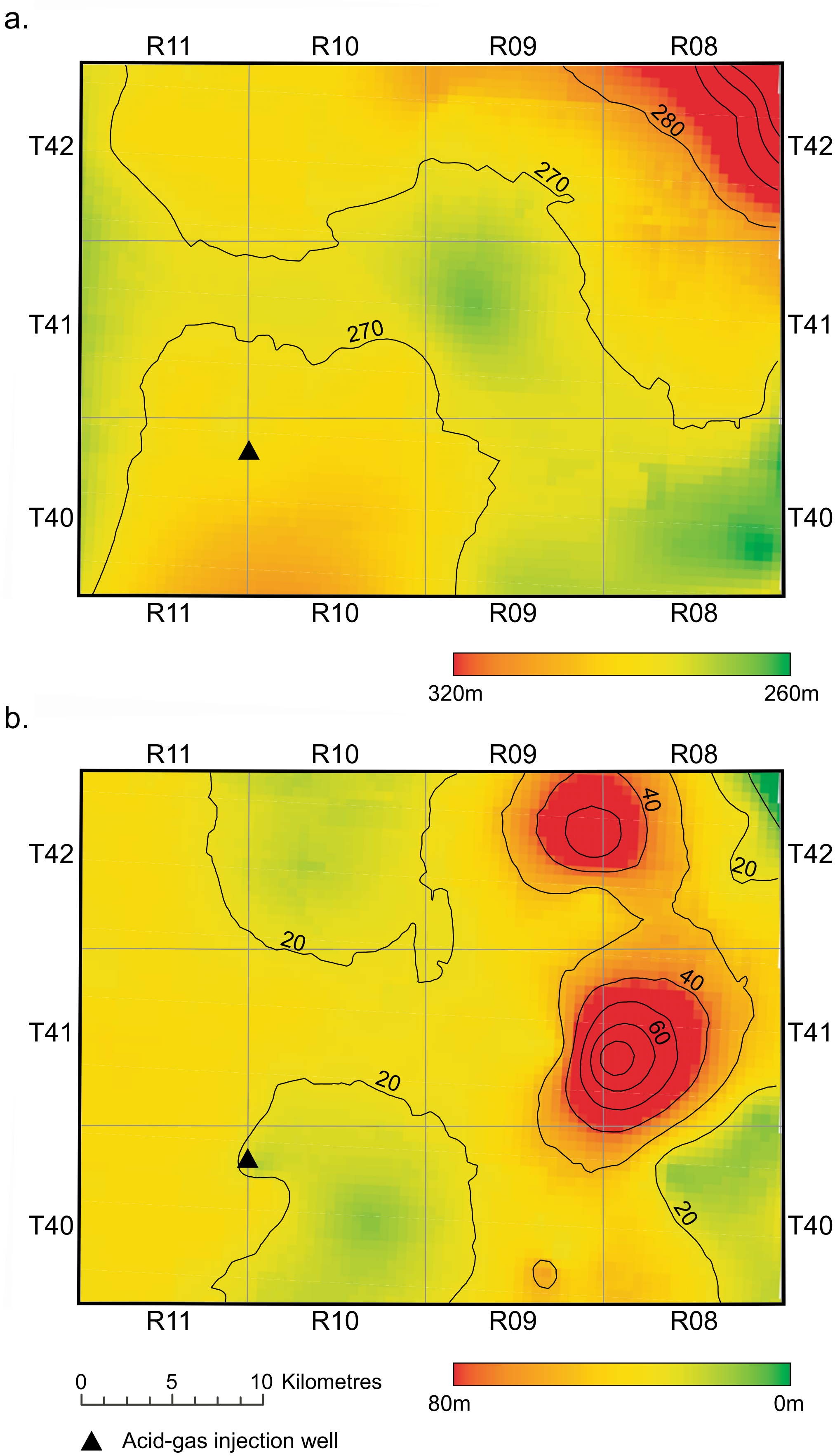


Figure 62. Isopach maps in the Thompson Lake local-scale study area: a) Leduc Formation and b) Ireton Formation. The location of the injection well is also shown. Contour interval = 10 metres.

mostly tight limestones, and shaly limestone of the Beaverhill Lake Group, with a combined thickness of more than 150 m.

5.5.2 Hydrogeological Characteristics and Rock Properties

There is no hydrocarbon production from the Leduc Formation in the Thompson Lake area and therefore a very limited amount of hydrogeological data exists.

Chemistry of Formation Waters

Formation water in the Leduc-Cooking Lake aquifer in the Thompson Lake area is of a Na-Cl type, with an average of 25.4 g/l sodium and 45.7 g/l chloride (Table 14). Calcium, magnesium, sulphate and bicarbonate are present in minor concentrations (Figure 59b). Five analyses were actually performed on samples from the Provost-Leduc injection well. The salinity of Leduc-Cooking Lake formation water decreases slightly from approximately 80 g/l in the east to 60 g/l in the east (Figure 63a), continuing the trend in the Galahad area to the west. The average in-situ brine density in the Thompson Lake area was calculated to be 1057 kg/m^3.

Table 14. Major ion chemistry of brines from the Leduc-Cooking Lake aquifer in the Thompson Lake area (concentrations in g/l). * indicates analysis from the acid-gas injection well.

	Na	K	Ca	Mg	Cl	SO_4	HCO_3	TDS
12-30-040-10-W-4*	25.0	0.8	2.3	0.3	44.8	0.02	1.3	74.5
	25.0	0.9	2.2	0.4	44.8	0.01	1.3	74.5
	22.0	0.8	2.6	0.3	39.9	0.03	1.3	66.9
	29.0	1.0	2.1	0.9	45.9	0.01	1.4	80.2
	25.8	0.8	2.1	0.9	46.1	0.02	1.3	76.9
06-35-040-11-W-4	24.7	0.9	1.9	0.9	46.7	0.02	0.8	76.0
08-20-042-11-W-4	28.3		3.6	1.1	52.5	0.02	1.0	86.0
16-20-041-10-W-4	27.7		3.6	1.8	53.6	0.13	1.2	87.5
11-16-042-08-W-4	20.8	0.6	1.7	0.9	37.0	0.29	0.9	61.2
Minimum	20.8	0.6	1.7	0.3	37.0	0.01	0.8	61.2
Maximum	29.0	1.0	3.6	1.8	53.6	0.29	1.4	87.5
Average	25.4	0.8	2.5	0.8	45.7	0.06	1.2	76.0

Pressure Regime

Pressure data from the Leduc Formation in the Thompson Lake area are very limited, consisting of only four pressure values derived from drillstem tests and a series of five pressure measurements from a repeat formation test (RFT) in a well in the direct vicinity of the acid-gas injection well. Therefore, the contour map of hydraulic head values (Figure 63b) also takes into account data from outside the local study area and the regional trend from Figure 31. The inferred flow direction of formation water in the Leduc-Cooking Lake aquifer is to the northwest and the average lateral hydraulic gradient is relatively low (< 1 m/km).

Pressure values from the Leduc Formation are plotted versus elevation and compared to pressures in overlying formations (Figure 64). Data from the Lower Mannville aquifer spread between gradient lines that correspond to 400 to 450 m hydraulic head. The Leduc pressure data plot at the lower end of this range, indicating that there might exist some pressure communication across the intervening Ireton aquitard and the potential for the natural vertical flow is downward from the Lower Mannville into the Leduc-Cooking Lake aquifer. However, hydrocarbon production from

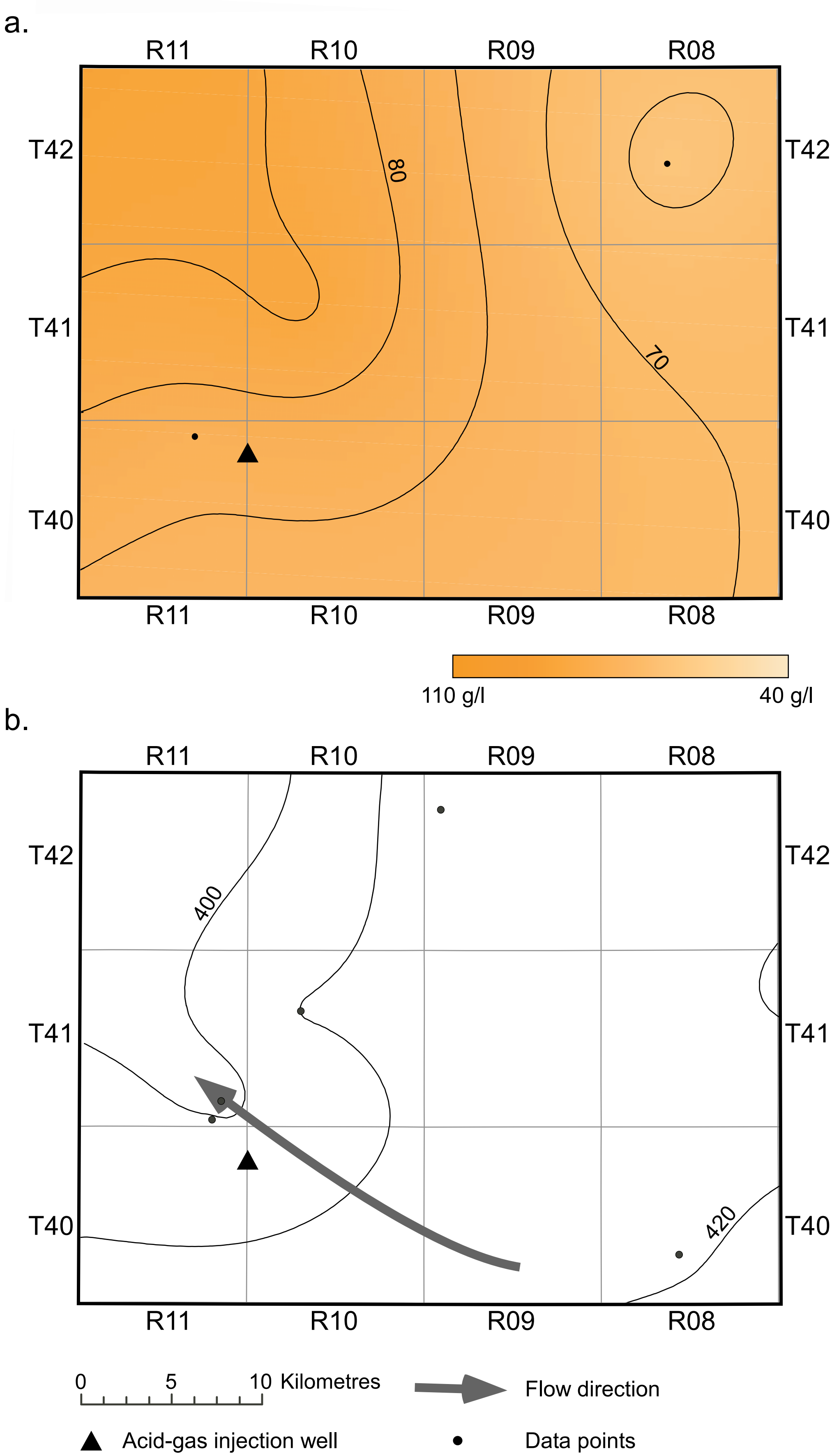


Figure 63. Distribution of: a) salinity (g/l) and b) hydraulic heads (m) in the Leduc-Cooking Lake aquifer in the Thompson Lake local-scale study area. The location of the injection well is also shown. Contour intervals are 5 g/l and 10 metres, respectively.

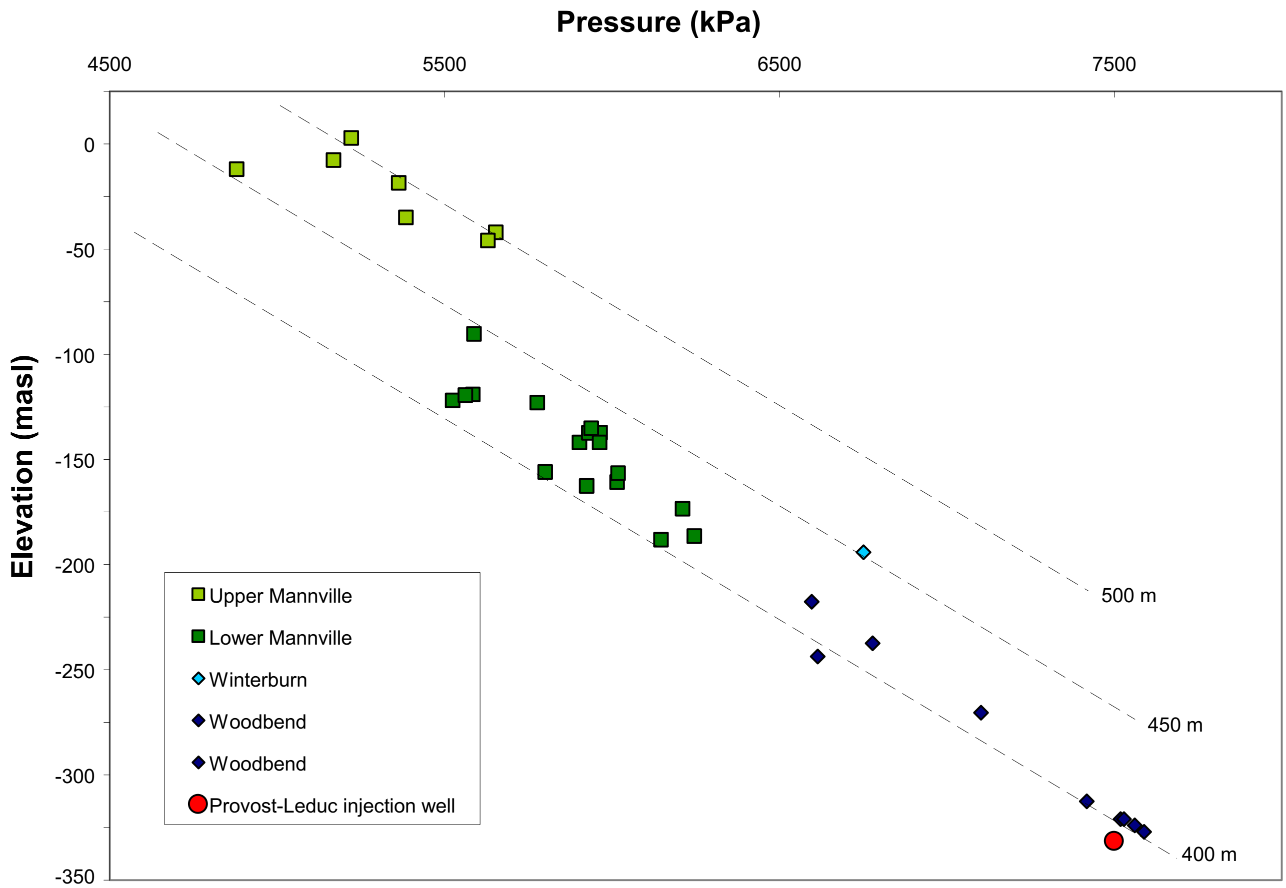


Figure 64. Distribution of pressure versus elevation in the injection strata and adjacent formations in the local-scale study area of the Thompson Lake acid-gas injection operation. The dashed lines delineate pressure-elevation trends with equal hydraulic-head values and the potential for vertical flow may be inferred perpendicular to those lines from high to low values.

pools in the Lower Mannville Group has caused significant pressure depletion in the Lower Mannville aquifer, reversing the potential of the vertical flow direction. Upper Mannville pressure values are considerably offset towards a higher equivalent hydraulic head value of approximately 500 m, which suggests that a barrier to flow exists between Upper and Lower Mannville aquifers and that the vertical potential for flow is downward.

Rock Properties

No core analysis data from the Woodbend Group exist for the Thompson Lake area. The median permeability of Leduc strata calculated from drillstem test analyses is approximately 3 mD (Table 15).

Table 15. Permeability values calculated from 4 drillstem test analyses performed in the Leduc Formation.

	Porosity (%)			Horiz. Perm. (mD)			Vert. Perm. (mD)			DST Perm. (mD)		
Formation	Min	Max	Avg	Min	Max	Median	Min	Max	Median	Min	Max	Median
Ireton	No data											
Leduc/CKLK										0.3	100	2.9

Flow of Formation Water

Flow of formation water in the Leduc-Cooking Lake aquifer in the Thompson Lake area is northwestward with an approximate horizontal gradient of 1 m/km in the vicinity of the Provost-Leduc injection site. As in the neighbouring Galahad study area, the effectiveness of the Ireton aquitard is questionable in the Thompson Lake area as shown by comparable ranges of salinity and hydraulic head values in the Lower Mannville and Leduc-Cooking Lake aquifers (Figures 27 and 29a).

5.6 Summary of the Local-Scale Hydrogeological Analysis

With the exception of the Provost-Keg River acid-gas injection operation, acid gas in the Provost area is injected into the Lower Mannville to Woodbend succession. In all local-scale areas, hydrogeological data suggest that the Upper Mannville aquifer is clearly hydraulically disconnected from the Lower Mannville and deeper aquifers. However, within the Lower Mannville to Woodbend succession various aquitards can be either absent due to pre-Cretaceous erosion or thin above Woodbend Group reef and platform carbonates. Consequently, hydraulic communication between the Lower Mannville, Wabamun, Winterburn and Leduc-Cooking Lake aquifers appears to exist in places as demonstrated by similar ranges in salinity and hydraulic-head values in these aquifers. Specifically, the anomalously high salinity (< 80 g/l) of formation waters in large parts of the Lower Mannville aquifer originate from mixing with Mississippian and Devonian brines, showing that hydraulic communication between Paleozoic aquifers and the Lower Mannville aquifer have existed in the past. In addition, hydrocarbons in the Lower Mannville Group pools originate from Mississippian and Devonian source rocks (Riediger *et al.,* 1999). In contrast, significantly higher salinities in the Beaverhill Lake and Keg River aquifers show that these aquifers, and specifically the injection horizon at the Provost-Keg River acid-gas injection operation, are vertically isolated from flow in overlying aquifers.

5.7 Site Specific Characteristics of the Acid Gas Operations

The site-specific characteristics of the acid gas operations in the northeastern Provost area are summarized in Table 16. The information contained therein has been compiled from the applications submitted by operators to the Alberta Energy and Utilities Board (EUB) in the process of obtaining approval for these operations, and from other sources.

At three of the six acid-gas injection sites in the Provost area (Hansman Lake, Bellshill Lake and Galahad), sour water was injected at least at some point during their time of operation. At Hansman Lake, sour water was injected between 1995 and 1997, but the operation was rescinded because of the closure of the associated gas plant. At Bellshill Lake, acid gas was added to the initial waste water stream in 1995, although the official approval by the EUB was not issued before 1998. Sour water was also injected at Galahad from 1993 to 1999, after which the operator switched to the injection of dry acid gas. The composition of the injected acid gas is approximately 80% CO_2 and 20% H_2S at all injection operations except for Bellshill Lake, where up to 35% hydrocarbon gases, specifically methane, are part of the injection stream. The depth of the injection interval varies between 809 m at Hansman Lake and 1433 m at the Provost-Keg River operation.

With respect to the reservoir geology, operators usually identify and characterize the first stratigraphic unit that overlies the injection horizon as caprock. It is difficult to quantify the sealing capacity, which depends on the caprock thickness and permeability, of which the latter is generally not known. Most often the integrity of seals and aquitards is assessed indirectly by comparing pressures and water chemistry in the over- and underlying reservoirs or aquifers. In fact, only for the Bellshill Lake-Blairmore, Hansman Lake-Cummings and Provost-Keg River operations, pressure-elevation plots indicate that the overlying aquitards prevent cross-formational flow from the injection horizon into overlying aquifers. In the cases of the Kelsey-Wabamun, Galahad-Leduc, and Provost-Leduc, the caprock identified by the operator is either thin or has non-aquitard lithology, and no obvious hydraulic separation of injection horizons and overlying aquifers can be deduced from pressure and salinity distributions. However, no breakthrough of acid gas has been reported to date in any wells producing from potentially affected horizons, which suggests that the injected acid gas remains within the injection horizon.

Detailed downhole stratigraphic models for the injection sites are shown in Appendix 1. The operators indicate site-specific porosity and permeability values for the injection horizon that are within the range of and generally close to the average local-scale values (Tables 7, 9, 11, 13 and 15).

Vertical stresses, S_V, at the top of the various injection intervals vary between 17.2 MPa at 809 m depth and 32.4 MPa at 1416 m depth, reflecting the thickness and density of the strata that overlie the injection interval (Table 16). The gradient of the vertical stress was determined from density logs of the injection well, or, where this was incomplete or not available, combined with wells in the vicinity of the injection well. The gradient varies slightly between 21.2 kPa/m and 22.9 kPa/m, reflecting variations in rock density. Minimum horizontal stresses, S_{Hmin}, in the five injection intervals vary between 12.3 MPa and 22.8 MPa (Table 16) and corresponding gradients between 13.0 kPa/m to 16.1 kPa/m, reflecting variations in the rock properties, injection depth and stress distribution. The rock-fracturing threshold in each well is between S_{Hmin} and S_V, but generally closer to S_{Hmin}. If the bottom hole injection pressure (BHIP) reaches the S_{Hmin} value, pre-existing fractures, if present, may open up. If no fractures are present, and there is no indication that there are any (except maybe around the well bore), the pressure has to increase

Table 16. Characteristics of acid-gas injection operations in the Provost area.

	Operation Description	Bellshill Lake	Galahad	Hansman Lake	Kelsey	Provost-Keg River	Provost-Leduc
Injection Operations	**Gas Plant**	Bellshill Lake Plant	Hastings Coulee Plant	Caribou Gas Plant	Holmberg Plant	Provost Gas Plant	Thompson Lake Gas Plant
	Current Operator	Viking Energy Ltd.	Husky Energy	EnCana Corporation	Thunder Energy Inc.	Husky Energy	Husky Energy
	Approval Date	11-May-98	28-Dec-93	18-Apr-95	27-Apr-99	20-Dec-94	24-May-95
	Status	active	active	rescinded	active	active	active
	Location (DLS)	03-28-041-12-W4	01-14-041-15-W4	09-08-040-03-W4	11-16-044-18-W4	08-14-040-03-W4	13-30-040-10-W4
	Latitude (N)	52.55000	52.52492	52.42620	52.79585	52.43959	52.47665
	Longitude (W)	-111.67000	-112.04690	-110.36860	-112.56050	-110.3194	-111.44140
	KB Elevation (m AMSL)	910.0	905.0	1120.0	1069.0	1057.0	715
	Depth of Injection Interval (m)	913-984	1200-1310	809-838	1167-1197	1416-1433	1020-1130
	Average Injection Depth (m)	949	1255	823.5	1182	1424.5	1025
Reservoir Geology	**Injection Formation Name**	Basal Quartz Fm.	Leduc Fm.	Cummings Mbr.	Wabamun Gp.	Keg River Fm.	Upper Leduc Fm.
	Injection Formation Lithology	Sandstone	Dolostone	Sandstone	Limestone	Dolostone	Dolostone
	Injection Formation Thickness (m)	71	110	29	30	17	112
	Net Pay (m)	58		2	4	10	40
	Caprock Formation	Glauconitic & Clearwater Fms.	Ireton Fm.	Lloydminster Mbr.	Wabamun-Ellerslie Fms.	Prairie Fm.	Nisku Fm.
	Caprock Formation Lithology	Shale and siltstone	Shale	Siltstone	Lime-mudstone	Salt	Dolostone
	Caprock Thickness (m)	150	22	30	7	185	20
	Underlying Formation	Wabamun-Winterburn	Duvernay Fm.	Woodbend Gp.	Graminia-Blueridge Fms.	Cambrian	Lower Ireton
	Underlying Formation Lithology	Limestone	Shale	Shale & Carbonate	Shaly siltstone	Siliciclastics	Shale
	Underlying Thickness (m)	35	83	250	10	300	30
Rock Properties	**Porosity (fraction)**	0.26	0.10	0.30	0.13	0.06	0.22
	Permeability (md)	413	100	4250	6	14	67
	S_V (MPa)	19.4	27.3	17.2	26.2	32.4	28.8
	S_V Gradient (kPa/m)	21.2	22.8	21.2	22.5	22.9	21.5
	S_{HMIN} (MPa)	13.9	16.6	12.3	18.4	22.8	17.4
	S_{HMIN} Gradient (kPa/m)	15.2	13.8	15.2	15.8	16.1	13
Reservoir Properties	**Original Formation Pressure (kPa)**	7214	9465	5717	8900	13790	7500
	Formation Temperature (°C)	34.0	39.0	29.0	45.0	38.0	35
	Reservoir Volume (1000 m^3)	n/a	137	230	201.4	241	5084
Formation Water	**TDS Calculated (mg/L)**	87021	95878	83277	119387	341430	78924
	Na (mg/L)	29596	27100	28600	37200	106920	24330
	Ca (mg/L)	2769	11100	1740	7110	21976	3160
	HCO_3 (mg/L)	758	771	1190	299	126	971
Licensed Injection Operations	**Injected Gas - CO_2 (mole fraction)**	0.54	0.67	0.65	0.77	0.79	0.76
	Injected Gas - H_2S (mole fraction)	0.12	0.19	0.24	0.19	0.20	0.19
	Maximum Approved H2S (mole fraction)	NA	0.20	0.24	0.25	0.25	0.21
	Maximun Approved WHIP (kPa)	11000	9000	NA	9800	10000	8000
	Maximum Approved Injection Rate (1000 m^3/d)	NA	35	12	11	24	45
	Total Approved Injection Volume ($10^3 m^3$)	NA	64000	16000	41000	86000	160000
	EPZ (km)	0.25	2.40	NA	2	1.20	1.5

beyond S_{Hmin} to overcome the compressive strength of the rocks, at which time the rocks will fracture. However, fractures may be limited to reservoir rocks only and may not propagate into the caprock. In order to avoid reservoir fracturing, EUB regulations require that the maximum BHIP be less than 90% of the fracturing threshold. Maximum BHIPs as set for the studied acid-gas injection operations are safely below the S_{Hmin} (Figure 65; thus, if the maximum BHIP is reached, there is no danger of opening pre-existing fractures, if any exist.

According to regulations of the EUB, acid-gas injection operators must submit annual or bi-annual progress reports that contain operating information, such as injection rate, volume and gas composition, and wellhead pressure and temperature. This information has been captured and is presented in Appendix 2, in individual Summary Reports for each of the operations in the Provost area.

Because the injected acid gas may react with the formation rocks and fluids, it is important to know the geochemical composition of the rocks at each site. The results of mineralogical analyses and modeling of potential geochemical reactions between the injected acid gas, and formation water and rocks will be presented in a separate report (Talman and Buschkuehle, in preparation).

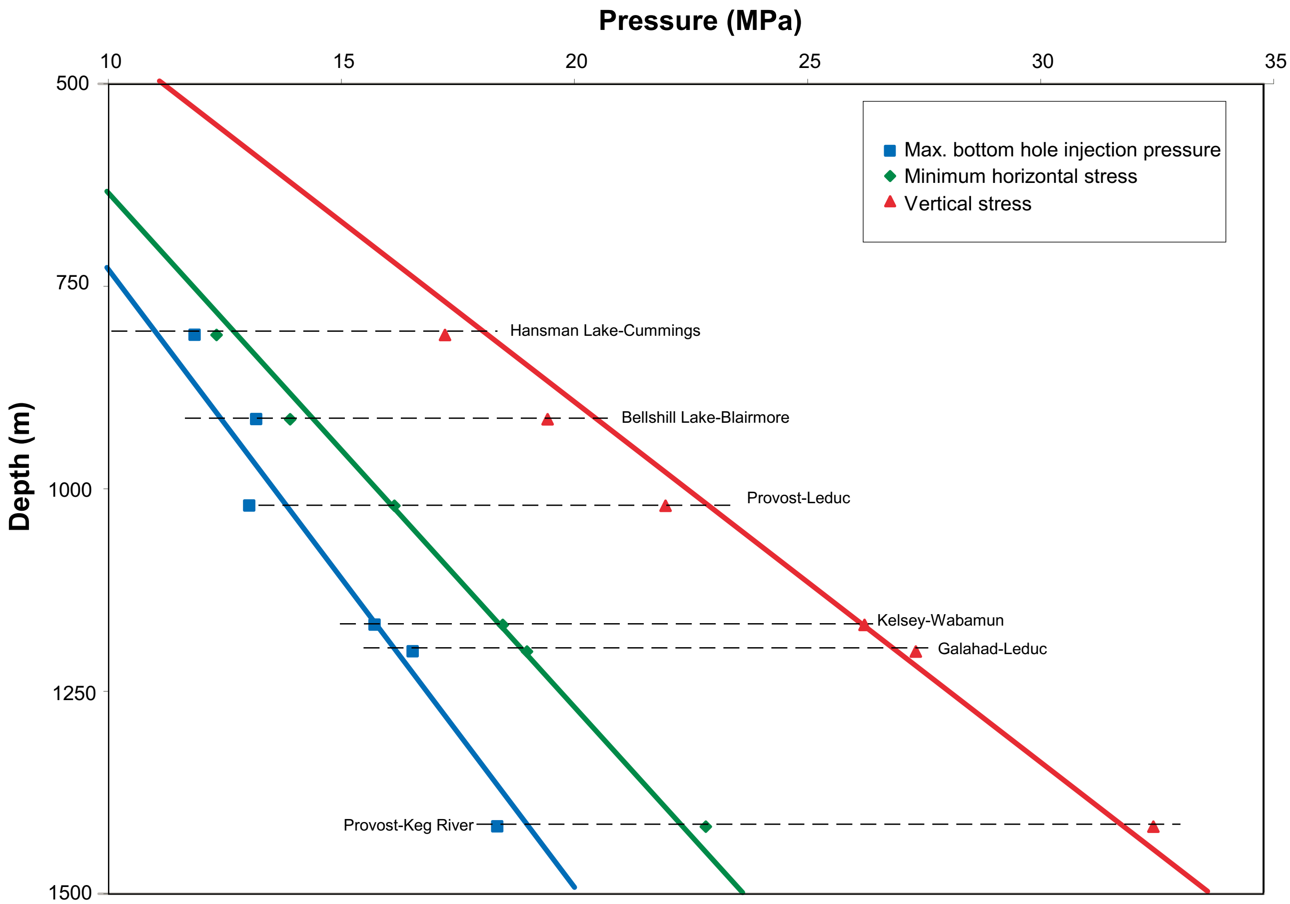


Figure 65. Maximum bottom-hole injection pressure in relation to minimum horizontal stress and vertical stress at the various injection sites in the Provost area. Coloured lines represent linear regression (intercept of zero MPa at zero metres depth) through respective data points.

6 Discussion

Based on the hydrogeological analysis of the acid-gas injection sites at local, regional and basin scales presented in the preceding chapters, the potential for acid gas migration and/or leakage from the injection sites in the Provost area can be qualitatively assessed. Migration is defined here as flow along bedding within the same formation (reservoir or aquifer). Leakage is defined as upward flow to overlying formations and possibly to the surface. Both will be considered in the context of the natural hydrogeological setting and of man-made features, such as pressure drawdown, wells and induced fractures.

The containment characteristics of the injected acid gas in the case of the six injection sites in the Provost area can be split into two categories:

- Injection of sour water into producing oil reservoirs at Hansman Lake and Bellshill Lake.
- Injection into deep saline carbonate aquifers at Kelsey, Galahad, Thompson Lake and Provost-Keg River.

The containment of the injected acid gas has to be assessed differently for aquifers and producing hydrocarbon reservoirs. Reservoirs usually have well defined vertical and lateral boundaries, within which the hydrocarbons were trapped initially and, after hydrocarbon production, the injected acid gas will be confined. Aquifers, although confined vertically by aquitards, generally have a large areal extent (defined in reservoir engineering as an infinite aquifer), and there are no lateral physical constraints to the flow of the injected acid gas.

6.1 Injection of Sour Water into Producing Oil Reservoirs

Because sour water rather than “dry” acid gas was or is injected at Hansman Lake and Bellshill Lake, these two cases will be treated separately from the other four injection sites in the Provost area. Initially, oilfield produced water was injected (disposed of) at these two sites. Subsequently the operator was granted permission to co-dispose of acid gas by dissolving it into the produced water prior to injection. Currently, both the Bellshill Lake-Blairmore and the Hansman Lake-Cummings I pools are still producing oil from the Lower Mannville Group. The annual volumes of water production and injection have the same order of magnitude and both have increased exponentially during the life of the two reservoirs (Figure 66). Therefore, a portion of the injected sour water is most likely produced back through the active oil wells and, in the case of the Bellshill Lake operation, re-injected. The production wells, as long as they are active, represent fluid sinks, ensuring that the injected sour water does not migrate beyond the boundaries of the respective oil pools.

After production from the Bellshill Lake-Blairmore and Provost-Cummings I pools has ceased and pool pressures have equilibrated, the injected sour water will be redistributed within the respective injection horizon due to density differences between disposal water and the Lower Mannville formation water. Dissolution of acid gas leads to an increase in water density by 2-4% (see Bachu and Adams, 2003, for the case of pure CO_2). Although the produced water in both cases is generally from the Lower Mannville, its density is not necessarily equal to that of in-situ formation water because the produced water loses dissolved gases as it is brought to the surface. If the density of the injected water is less than the density of formation water, then the injected sour water will rise to the top of the water leg in the reservoir and will be confined within the Lower Mannville channel sands. Mixing with and diffusion within the formation water in the Lower Mannville reservoir sands will occur over time. On the other hand, if the injected sour water is heavier than the formation water, then it will drop to the bottom of aquifer, generating

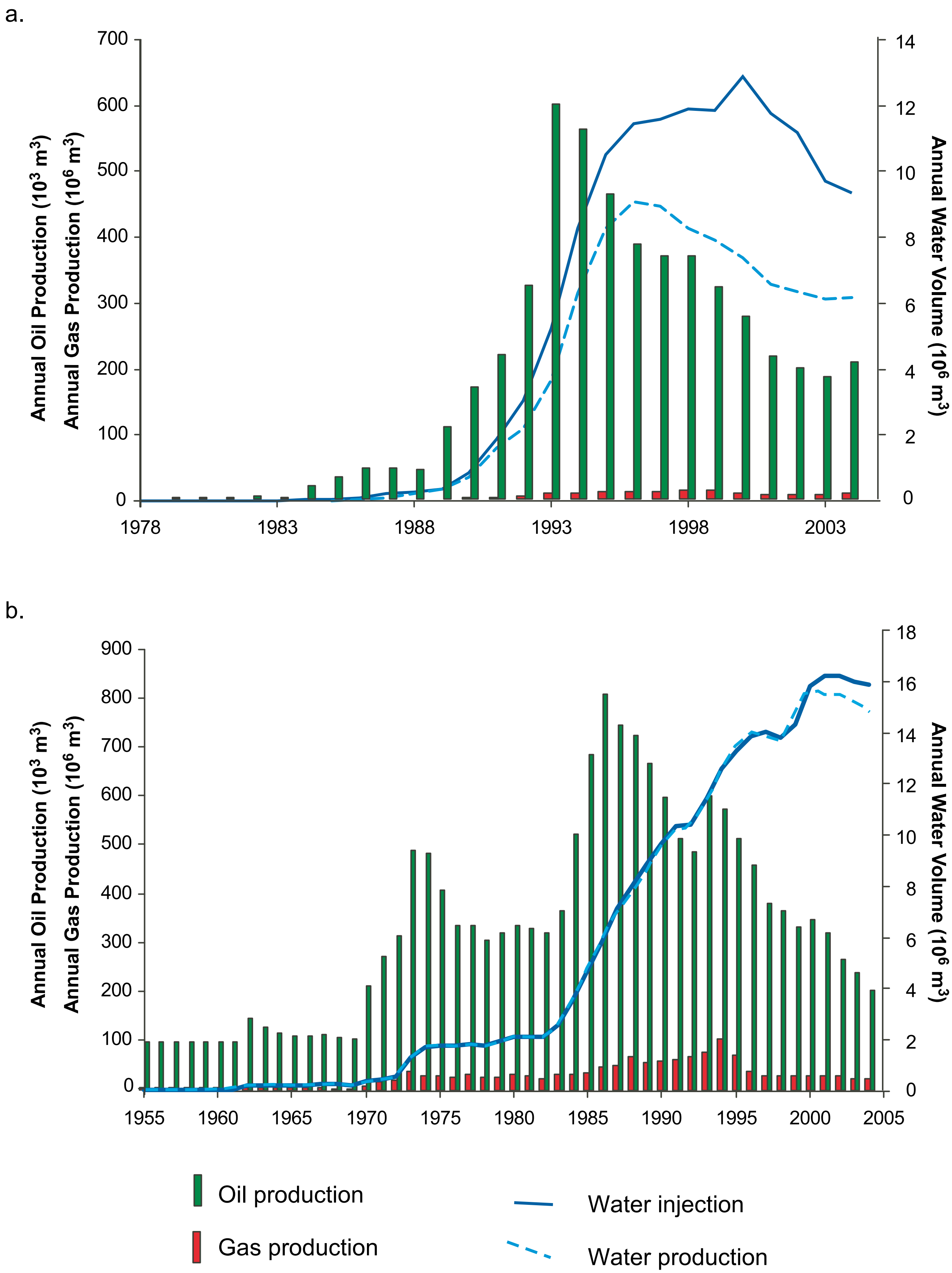


Figure 66. Production-injection history of the: a) Hansman Lake-Cummings I pool and b) Bellshill Lake-Blairmore pool.

convective flow. There, the sour water will be subjected to hydrodynamic forces in the natural flow system of the Lower Mannville aquifer and to negative buoyancy that will drive the water downdip.

6.1.1 Hansman Lake-Cummings

At Hansman Lake, sour water was injected into the Provost-Cummings I pool for 15 months from 1995 to 1996, resulting in a total injection volume of 2.6 million cubic metres of acid gas. Acid-gas injection was rescinded due to the decommissioning of the associated gas plant. Although the addition of acid gas to the disposal stream has ceased, there are still 34 wells that dispose of water into the injection horizon (Figures 67 and 68a). At the same time, 271 wells currently produce oil and large amounts of water from the Cummings Member (Figure 68a), and migration of sour water will be constrained to the pool outline by the injection-production cycle. An additional 7 wells produce from the overlying Upper Mannville Group. Only after production has ceased, downdip migration of sour water in a westward direction, following natural formation water flow, beyond the pool boundaries becomes a possibility. The flow magnitude will be on the order of 0.7 m/year, estimated on the basis of a hydraulic gradient of 1 m/km an average permeability value of 600 mD. At this slow flow velocity, the sour water will mix with and diffuse further within the formation water, such that the plume of injected water will ultimately disappear.

The potential for vertical flow of formation water is downwards from shallow aquifers into the Lower Mannville aquifer in the Hansman Lake area and buoyancy effects between the injected water and formation water are small. Therefore, vertical upward leakage of sour water from the injection horizon along potential faults or through aquitard windows is unlikely. For the same reason, the 45 abandoned and 115 suspended wells that penetrate the injection horizon, even if they should have corroded plugs or cements, would probably not allow any upward leakage of sour water to shallow groundwater or the ground surface. In addition, the first wells in the Hansman Lake area were drilled in the 1970s (Figure 68b) and well abandonment did not start before the 1980s (Figure 68c), when more stringent abandonment guidelines were in place.

6.1.2 Bellshill Lake-Blairmore

At Bellshill Lake, sour water has been injected into the Blairmore pool through 19 intermittently operating wells since 1995, and reportedly, 9.2 million cubic metres of acid gas were disposed of by the end of 2004. The Bellshill Lake field is a densely drilled area. Of the 756 wells that penetrate the injection horizon within the Blairmore pool, 473 wells currently produce hydrocarbons (Figures 69 and 70a), the majority (470) pumping oil from the Lower Mannville, and three from the overlying Viking Formation. In addition to the 19 sour water disposal wells, one well classified as “gas injector” disposes gas, oil and water into the Blairmore pool and a second well disposes of water into the Leduc Formation. Similarly, to the Hansman Lake operation, the injection of sour water largely compensates for the production-induced pressure depletion in the Blairmore pool, and any sour water migration beyond the pool is likely inhibited by the production-injection cycle.

Migration of sour water in response to the natural flow regime after the cessation of any pumping stress in the Blairmore pool will be towards the west at a velocity on the order of 1.8 m/year. At this flow velocity, based on a hydraulic gradient of 2 m/km and an average permeability value of 600 mD, the sour water will mix with and diffuse further within the formation water, such that the plume of injected water will ultimately disappear. In addition, similar to hydrodynamic conditions at Hansman Lake, the vertical potential for flow in the Bellshill Lake area is downwards from the

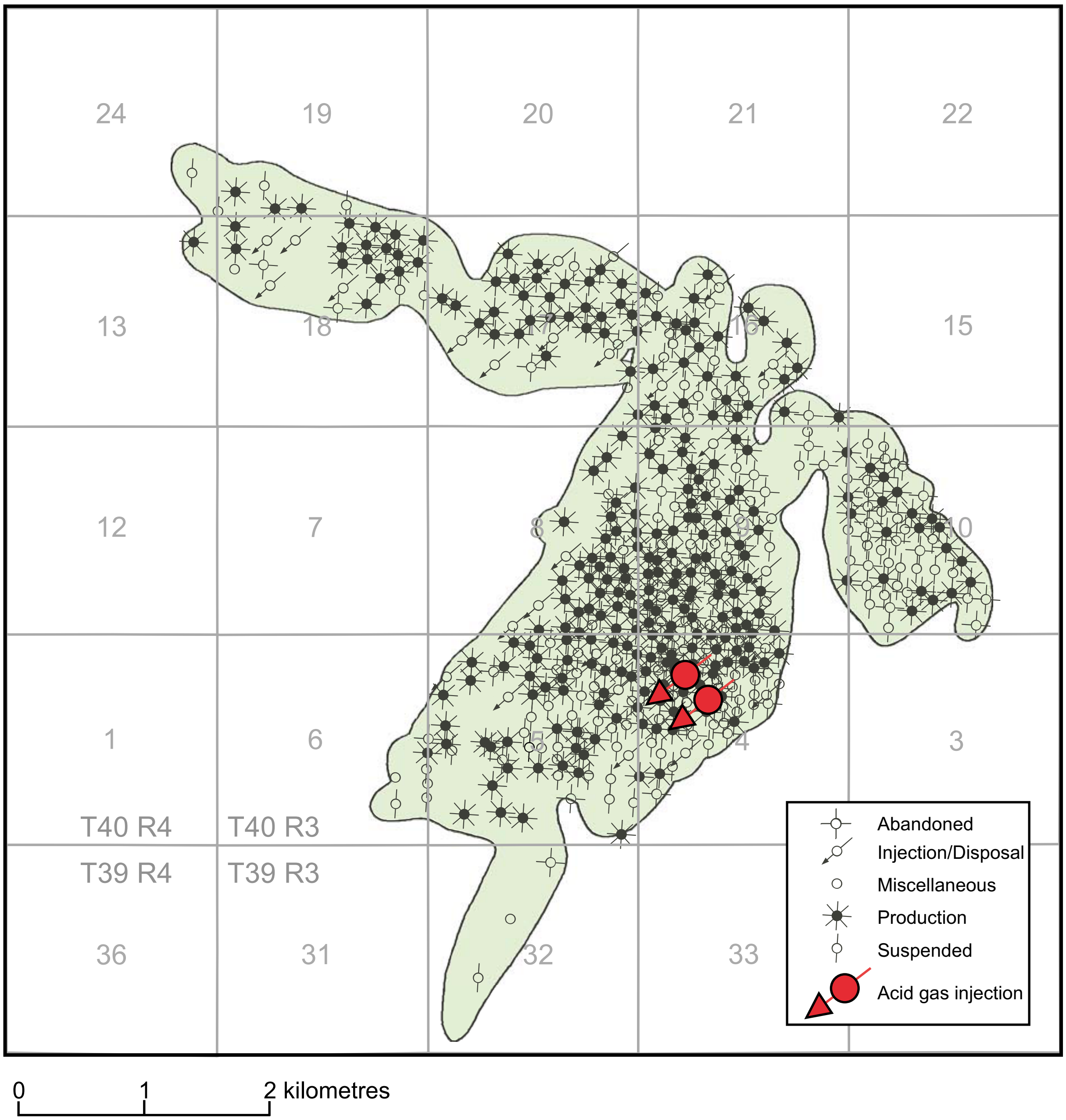


Figure 67. Location and current status of wells that penetrate the injection horizon within the limits of the Hansman Lake - Cummings I oil pool (in green).

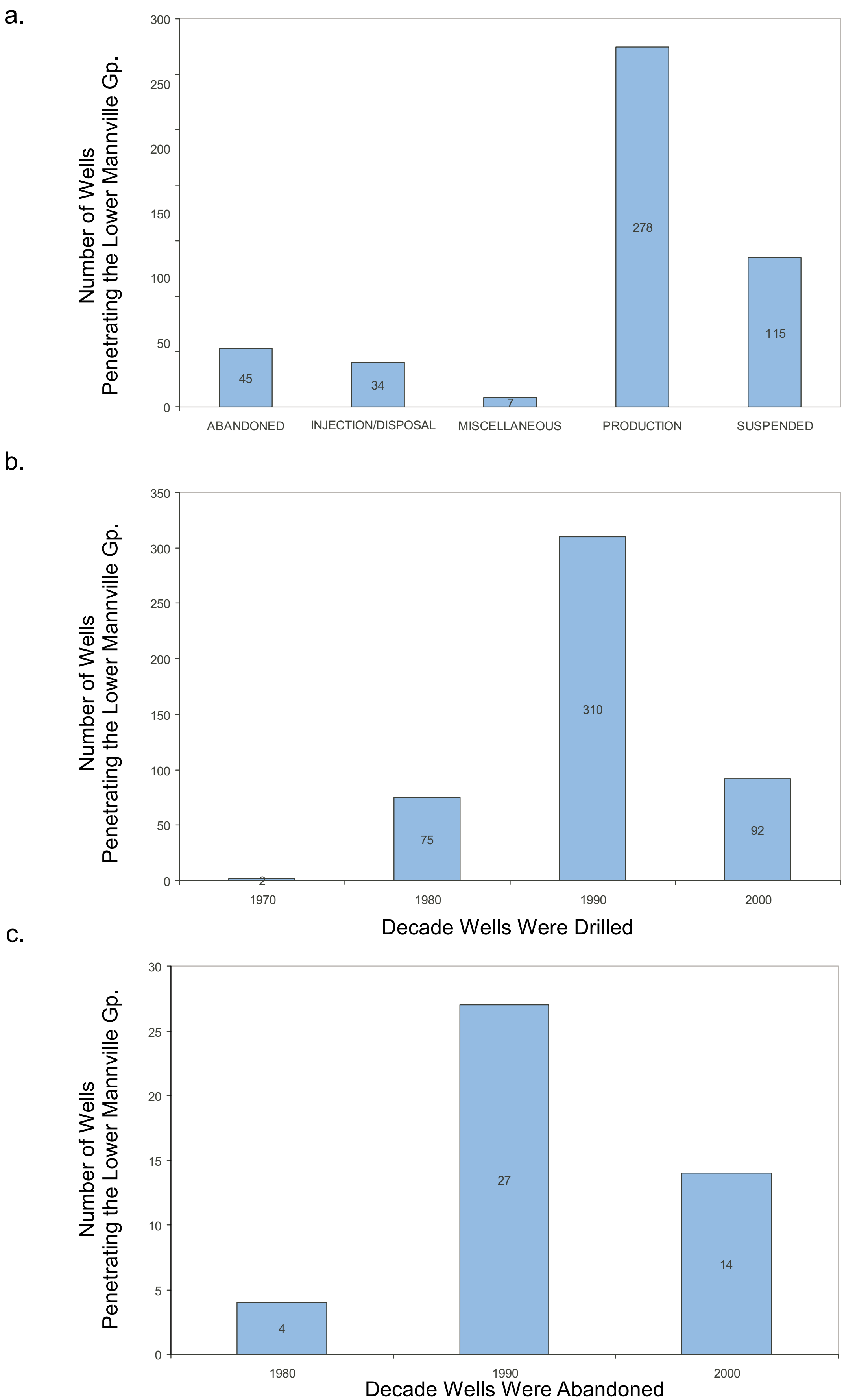


Figure 68. Histograms for wells that penetrate the Lower Mannville Group in the Hansman Lake - Cummings I pool showing: a) well status, b) time of drilling, and c) time of abandonment for abandoned wells.

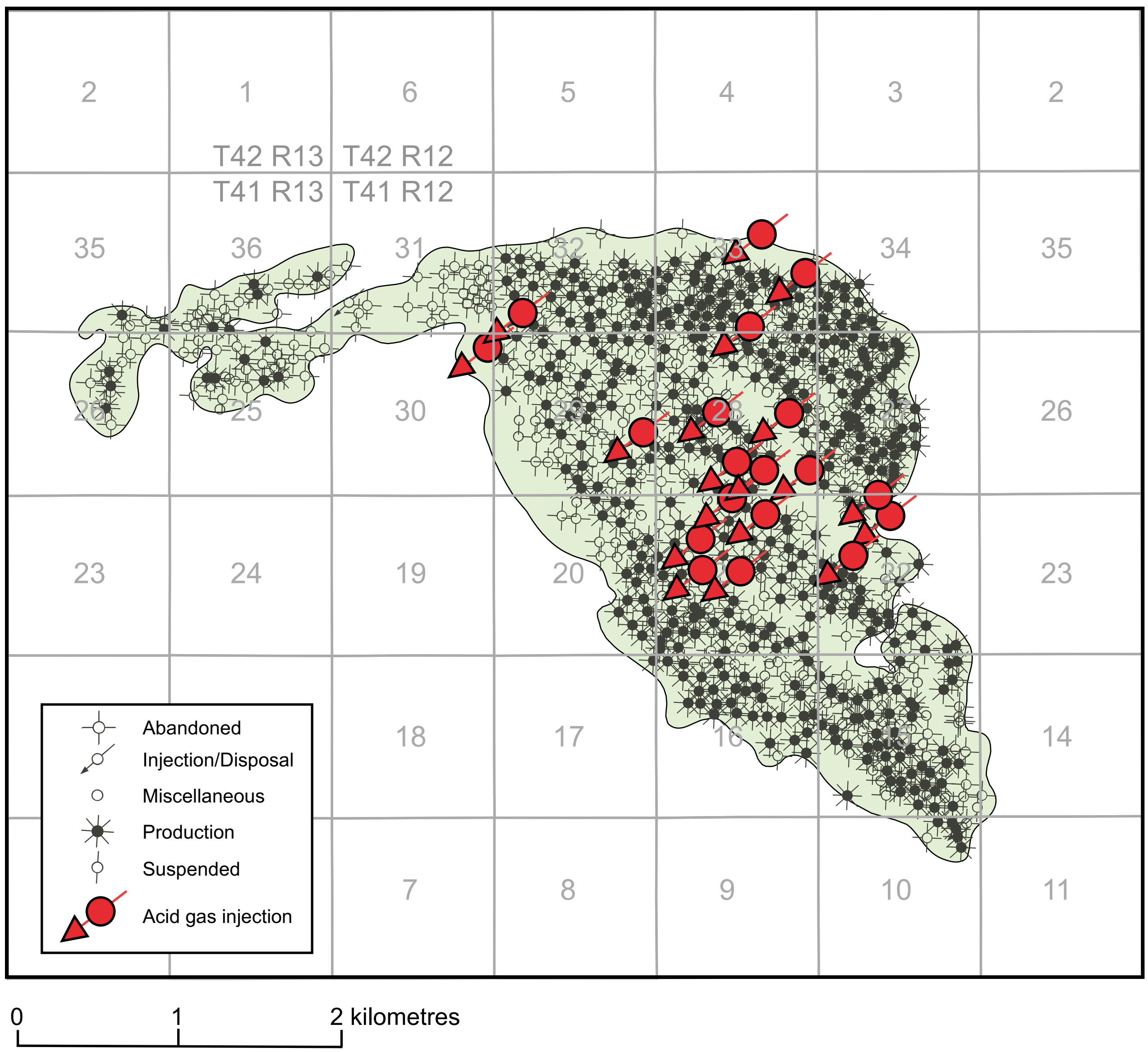


Figure 69. Location and current status of wells that penetrate the injection horizon within the limits of the Bellshill Lake - Blairmore oil pool (in green).

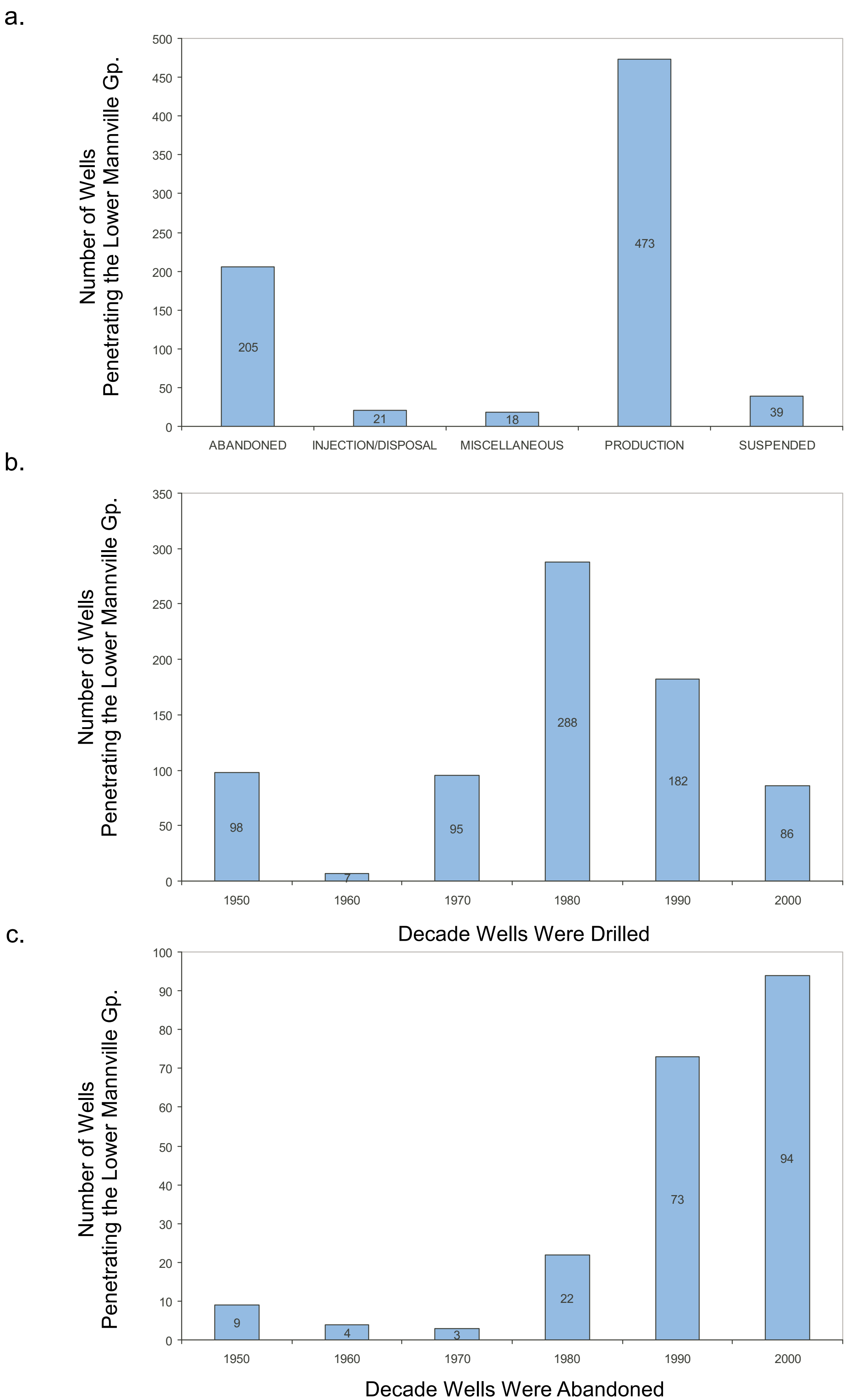


Figure 70. Histograms for wells that penetrate the Lower Mannville Group in the Bellshil Lake - Blairmore pool showing: a) well status, b) time of drilling, and c) time of abandonment for abandoned wells.

ground surface into the Lower Mannville, counteracting any possible upward leakage along faults, fractures, aquitard windows or well bores. Drilling in the area of the Bellshill Lake Blairmore pool commenced in the 1950s and a large number of wells was drilled in the 1980s (Figures 70b). Infill drilling started in the mid 1990s, adding to the high well density. Wells potentially most susceptible for cement degradation and casing erosion are the 13 wells that were drilled and abandoned in the 1950s and 1960s (Figures 70c), when guidelines for well abandonment were less stringent.

6.2 Injection of "Dry" Acid Gas into Regional Aquifers

Dry acid gas is injected into the Wabamun aquifer at Kelsey, into the Leduc-Cooking Lake aquifer at Galahad and Thompson Lake, and into the Keg River aquifer at Hansman Lake (Provost-Keg River). The fate of the injected acid gas is controlled by the in-situ properties of the gas and native fluid (reservoir gas or formation water). Table 17 presents the density and viscosity of the injected acid gas and native reservoir gas or formation water calculated for the initial in-situ conditions given in Table 16 (Adams and Bachu, 2003; Bachu and Carroll, 2004).

Table 17. Properties of native fluids and injected acid gas at in-situ conditions at the four operations in the Provost area where dry acid-gas is injected.

Fluid Property	Galahad	Kelsey	Provost-Leduc	Provost-Keg River
Native fluid	Water	Water	Water	Water
ρ (kg/m^3)	1056	1075	1052	1236
μ (mPa s)	0.62	0.74	0.82	1.32
ρ_{ag} (kg/m^3)	395	334	492	718
μ_{ag} (mPa s)	0.030	0.025	0.036	0.063
(1)max ρ_{ag} (kg/m^3)	660	692	750	789
(1)max μ_{ag} (mPa s)	0.060	0.060	0.067	0.075

(1) Values calculated for maximum approved bottom-hole injection pressures.

6.2.1 Mathematical Expression for the Lateral Migration of Separate-Phase Acid Gas

In an aquifer, acid gas flows as a result of the interplay between the hydrodynamic drive imposed by injection, the natural hydrodynamic drive in the aquifer and buoyancy. The flow velocity of acid gas in a sloping aquifer can be written with respect to a reference density ρ_0 as (Bachu, 1995):

$$v = \frac{q}{\Phi} = -\frac{k k_{rag} \rho_0 g}{\mu_{ag}} \left(\nabla H_0 + \frac{\Delta\rho}{\rho_0} \nabla E \right) \qquad (1)$$

Where q is the specific discharge or Darcy flow velocity, Φ is porosity, g is the gravitational constant, μ_{ag} is acid gas viscosity, k_{rag} is the relative permeability of the acid gas, ρ_0 is the reference density (that of formation water), $\Delta\rho$ is the density difference between the acid gas and formation water, ∇H_0 is the hydraulic head gradient, and ∇E is the slope of the aquifer. The first term in brackets in relation (1), ∇H_0, represents the hydrodynamic drive, and the second term represents buoyancy. The relative importance of the two driving forces is expressed by the driving force ratio (Bachu, 1995):

$$DFR = \frac{\Delta\rho}{\rho_0} \cdot \frac{|\nabla E|}{|\nabla H_0|_h} \tag{2}$$

where the subscript *h* denotes the horizontal component of the hydraulic gradient.

The hydrodynamic drive in turn has two components, one induced by injection and/or production (if present), and the second corresponding to the natural flow of formation water. The hydraulic gradient created by injection decreases logarithmically with distance from the well, such that in the vicinity of the well (near-field) the hydrodynamic drive induced by injection dominates the flow, while away from the injection well (far-field) it becomes negligible.

During injection of a non-aqueous fluid into an aquifer, the flow of the injected fluid in the near-field of the well is driven by injection hydrodynamics and by the density contrast between the two fluids (buoyancy), and is controlled by the viscosity contrast (mobility) between the two fluids. The following dimensionless parameter:

$$\Gamma = \frac{2\pi\Delta\rho g k k_{rb} B^2}{\mu_b Q} \tag{3}$$

represents the ratio of buoyant versus viscous and pressure forces, and is an indication of the importance of buoyancy (density differences) in driving the flow of the injected acid gas (Nordbotten *et al*., 2004a). In the above expression, porosity ϕ, permeability k (m^2) and thickness B (m) are aquifer characteristics, k_{rb} and μ_b (Pa·s) are, respectively, the relative permeability and viscosity of the formation water (brine) and express mobility (including viscous forces), Q (m^3/s) is the injection rate and expresses injection forces, and $\Delta\rho$ (kg/m^3) is the density contrast between the injected acid gas and formation water, expressing buoyant forces.

For $\Gamma < 0.5$ hydrodynamic and viscous forces dominate and buoyancy can be neglected in the near-field (Nordbotten *et al*., 2004a). In this case, the maximum spread of the plume can be estimated by:

$$r_{\max}(t) = \sqrt{\frac{\mu_b V(t)}{\mu_{ag} \Phi \pi B}} \tag{4}$$

This situation will happen for: 1) high injection rate (strong hydrodynamic force); b) small density difference between the injected gas and formation water (low buoyancy); and 3) injection into a thin and/or low porosity and permeability aquifer. At the other end of the spectrum, buoyancy totally dominates for $\Gamma > 10$. Such cases will occur for a combination of the following factors: 1) large density differences between the injected fluid and formation water; 2) injection into a thick aquifer characterized by high porosity and permeability; and 3) low injection rate (small hydrodynamic force). This estimate of r_{max} is based on a certain set of simplifying assumptions, such as no mixing and diffusion between the acid gas and aquifer brine, no gas dissolution in the brine, full saturation with either acid gas or brine in their respective domains, no capillary effects, and a sharp interface between the two fluids (Nordbotten *et al*., 2004a). All these assumptions by and large lead to overestimates of the plume spread because, in reality, some plume mass will be lost through dissolution, diffusion and mixing. In addition, saturations less than 100% and capillary effects will retard the gravity override and plume spread. On the other hand, in a sloping aquifer buoyancy will distort the plume, which will advance faster updip and slower downdip. As a result, the plume will become elongated along dip, with the downdip edge of the plume closer to and the updip edge of the plume farther from the injection well than the radial plume for a horizontal aquifer.

For $0.5 < \Gamma < 10$, buoyancy, hydrodynamic and viscous forces are comparably important (Nordbotten *et al*., 2004a). The change from one flow regime to another is not sharp, but rather gradual. These results are quite intuitive, because the injected acid gas will rise to the top of the aquifer (gravity override) if the aquifer has large enough permeability, porosity and thickness, and if the density difference is large enough; otherwise the plume will spread mostly laterally as a result of the strong hydrodynamic drive, being controlled by the mobility contrast between the two fluids.

After injection has ceased the migration of acid gas is governed by the natural hydrodynamics in the aquifer and buoyancy according to Equation 1. The relative importance between hydrodynamic and buoyancy driving forces can be assessed with Equation 2. Solving Equation 1 will give an estimate of the lateral migration velocity and direction of acid gas in the aquifer. The velocity is a force vector resulting from the vectorial summation of the hydrodynamic and buoyancy force vectors for homogeneous aquifer and fluid properties. Due to the naturally occurring variations in permeability and porosity, fluid properties, as well as local changes of aquifer slope and hydrodynamic gradient, which are difficult to fully capture over a large area, Equation 1 represents only an order of magnitude assessment of the regional direction and velocity of acid gas migration. In addition, during plume migration, acid gas will continuously come in contact with formation water, leading to the dissolution, diffusion and mixing of acid gas. As acid gas dissolves in formation water, this will become heavier than unsaturated brine, and a process of brine free convection will be set in motion (Lindeberg and Wessel-Berg, 1997). The heavier brine will drop to the bottom of the aquifer and then migrate downdip, while brine not saturated with acid gas will replace it and come in contact with the acid gas plume. This process will continue as the plume migrates, ultimately leading to the total dissolution of the acid gas plume (McPherson and Cole, 2000). In addition, acid gas will collect along the migration path in traps created by the uneven aquitard base at the top of the respective aquifer. In addition, not all of the injected acid gas will exist in a mobile phase, but some amounts will remain fixed in the pore space in the reservoir and along the flow path due to the effects of residual phase saturation (Holtz, 2003). As a result of all these processes (dissolution, dispersion, mixing, traps along the migration path, and residual saturation) the acid gas plume will migrate a finite distance from the injection well. Modelling studies of the migration of CO_2 in the subsurface have shown that the maximum distance of plume migration is in the order of a few tenths of kilometres (Ennis-King *et al*., 2004).

In the following, the lateral migration of acid gas will be assessed for the near- and far-fields of the various acid-gas injection sites that inject into aquifers. In addition, the potential for acid gas leakage through overlying aquitards and wells along the flow path will be discussed.

6.2.2 Near-Field Acid-Gas Migration During Injection

In the near-field (injection well and its vicinity), pressures are actually higher than the initial aquifer pressure. Since water is only very slightly compressible, and its density is affected mostly by temperature and salinity and very little by pressure (Adams and Bachu, 2003), the density values presented in Table 17 for formation water are valid even if pressure increases as a result of injection. However, for acid gas, whose properties are strongly dependent on pressure, the density is highest at the well and decreases away from the well as pressure drops, towards the values presented in Table 17. The bottom-hole injection pressure, although not measured, can be estimated based on the hydrostatic weight of the acid gas column in the well assuming average gas density. As an upper limit, pressures have to be always below 90% of the fracturing pressure. Using this upper limit for pressure, the maximum acid-gas density at the injection well would be 692 kg/m^3 at Kelsey, 660 kg/m^3 at Galahad, 750 kg/m^3 at Thompson Lake and 782 kg/m^3 at Provost-Keg River (Table 17). Thus, at each site, the density contrast between the injected acid gas and formation water will likely vary from approximately 1:1.5 at the injection well to 1:3 at the boundary of the area of influence, and the viscosity contrast will vary correspondingly from 1:10 to 1:20.

The average injection rates at surface pressure/temperature conditions to the end of 2004 were ~7,000 m^3/day at Kelsey, ~13,600 m^3/day at Galahad, 23,000 m^3/day at Thompson Lake, and ~15,500 m^3/day at Provost-Keg River. Considering full saturation in the regions occupied respectively by the injected gas and formation water (i.e., $k_{rb}=k_{rag}=1$), values of $\Gamma = 0.01$, $\Gamma = 0.6$, $\Gamma = 4.6$, and $\Gamma = 0.2$, respectively are calculated (Equation 3, Table 18).

Table 18. Injection characteristics of acid-gas injection operations in aquifers.

	Q (m^3/day)	V_{max} in-situ (10^3m^3)	Γ	R_{max}(m)
Kelsey-Wabamun	7000	216	0.01	1965
Galahad-Leduc	13600	273	0.6	1500
Provost-Leduc	23000	577	4.6	690
Provost-Keg River	15500	211	0.2	1530

Q = average injection rate; V_{max}in-situ = maximum approved injection volume at reservoir conditions; R_{max} = maximum spread of acid gas plume during injection calculated by Equation 4.

Injection hydrodynamics and viscous forces dominate in the cases of acid gas injection at the Kelsey and Provost-Keg River sites and Equation 4 will give an accurate estimate of the maximum plume spread. Relatively low injection rates at Galahad and a large aquifer thickness at Provost-Leduc are the main reasons why buoyancy cannot be neglected in the estimation of plume spread. Comparing results from Equation 4 with more elaborate, semi-analytic solutions indicates that Equation 4 underestimates the plume spread by up to 15% for cases where $0.5 < \Gamma < 3.0$ (Bachu *et al*., 2004a). Considering uncertainties in other parameters that affect plume spread, like permeability distribution, porosity and acid gas properties, a 15% error due to the neglect of buoyancy effects is deemed acceptable in an order of magnitude analysis of long-term acid-gas migration. For maximum volumes of acid-gas at the end of injection, the respective maximum radii of plume spread estimated using Equation 3 at the various injection sites range from 690 m to 1965 m. The maximum extent of plume spread during injection will be used as the starting point for the assessment of acid gas migration in the far-field of the respective injection wells at each injection site.

6.2.3 Kelsey - Wabamun

Injection of acid gas at Kelsey commenced in 1999 and 15 million cubic metres of acid gas have been injected by the end of 2004. The injection interval is within the Wabamun Group. However, no aquitard directly above the injection horizon could be clearly identified based on the interpretation of geological and hydrogeological data and the Wabamun and Lower Mannville strata appear to form a contiguous aquifer.

In the far-field, away from the injection well, the natural flow in the aquifer becomes dominant over the hydrodynamic drive caused by injection. In the vicinity of the Kelsey injection site the hydraulic gradient in the Wabamun-Lower Mannville aquifer is approximately ∇H_0 = 0.05% (0.5 m/km) at 45° to the northwest (Figure 71). The slope of the top of the aquifer is ∇E = 0.48% (4.8 m/km) at 58° to the northeast. Considering the density contrast between the injected acid gas and formation water (Table 17), the driving force ratio (DFR) is 6.6, which indicates that buoyancy is significantly stronger than the natural hydrodynamic drive in the aquifer. This means that the plume of acid gas will migrate generally to the northeast at ~50°. On the basis of the permeability and porosity values for the Wabamun-Lower Mannville aquifer (Table 8) and of acid gas and brine properties (Table 17), an order-of-magnitude analysis shows that, once outside the cone of influence around the injection well, the velocity of the updip migrating acid gas is on the order of 2 m/year or less (Figure 71), depending on relative permeability of acid gas k_{rag}. Even with the acceleration of acid-gas migration due to an increase in buoyancy at shallower depths, it would take theoretically more than 100,000 years before any laterally-migrating acid gas would reach the outcrop of the Lower Mannville aquifer, 350 km northeast of the injection site.

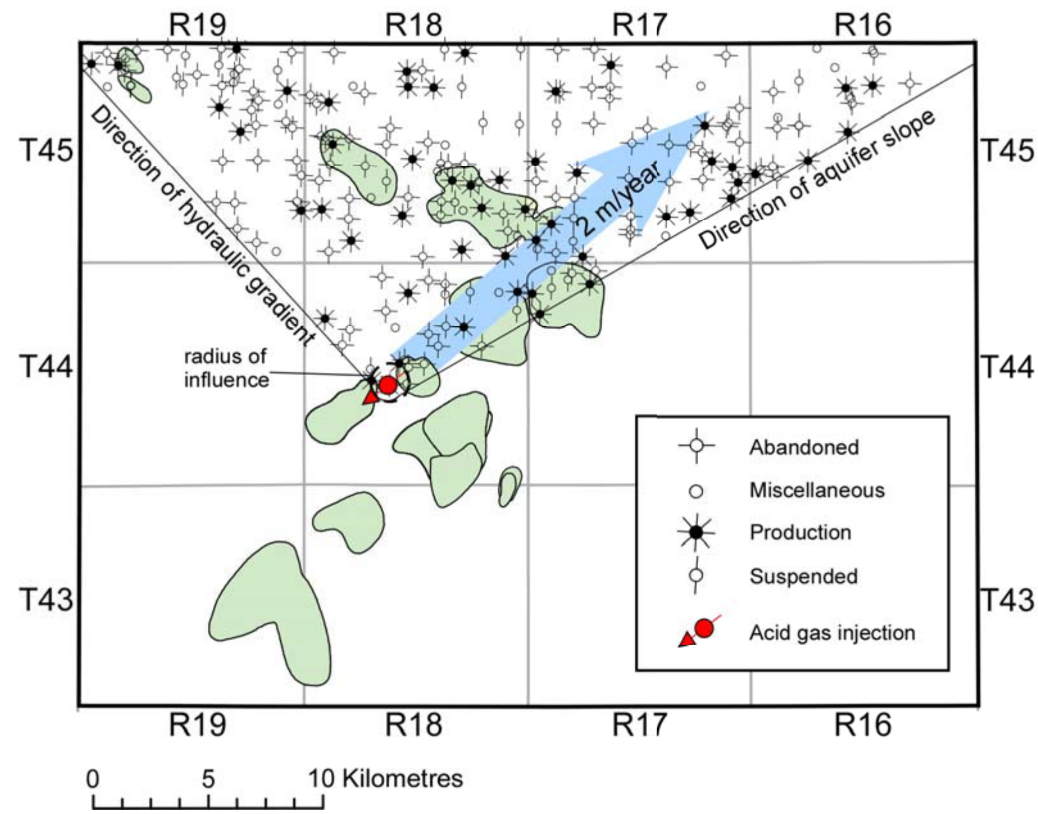


Figure 71. Assessment of long-term acid-gas migration at Kelsey, showing location and status of wells along the potential migration path and outlines of oil pools (in green) that produce from the Lower Mannville Group. The blue arrow represents the inferred flow direction of separate-phase acid-gas as a result of the vectorial summation of buoyancy and hydrodynamic drive (Equation 1).

As explained previously, the vertical migration of acid gas from the Wabamun injection zone into the overlying Lower Mannville Group is very likely due to the absence of intervening aquitards. Continuing upward leakage could potentially be possible through a) windows, natural faults and/or fractures in the aquitards units in the Upper Mannville, or b) induced fractures and/or improperly completed and/or abandoned wells. The heterogeneity of the Mannville Group strata makes it difficult to identify continuous hydrogeological units, especially in the Upper Mannville Group. However, the hydrogeological assessment has shown that there is clear hydraulic separation between Lower and Upper Mannville aquifers. In addition, the thick Colorado aquitard farther up in the stratigraphic column would effectively prevent any leakage to shallow aquifers or the ground surface, even if there were local cross-formational flow within the Mannville Group.

Wells that penetrate the injection horizon along the potential flow path of the acid gas in the Wabamun-Lower Mannville aquifer (Figure 71) represent possible leakage conduits to overlying formations and, ultimately, to the ground surface. Figure 72 shows histograms of status, age, and time of abandonment for these wells. Of the 206 wells, the majority were drilled in the last 20 years and more than two thirds were either abandoned or suspended. Fifty-three wells currently produce gas from Cretaceous formations, 18 of which are completed in the Lower Mannville Group. The gas-producing wells in the Lower Mannville represent potential pressure sinks for the injected acid gas, the closest of which is located just 40 m east of the injection well. However, only chemical analyses from the produced gas could show a change in acid gas content with time, indicating breakthrough of the injected acid gas. There is no production from the Wabamun Group in this area. There are 17 wells that are characterized as “miscellaneous”, which in this case mostly refers to “drilled and cased”.

6.2.4 Galahad - Leduc

At Galahad, 52 million cubic metres of acid gas acid gas have been injected into the Leduc-Cooking Lake aquifer between 1994 and 2005. The injection site is located at the western edge of the Devonian Killam Barrier Reef, which represents an important conduit for fluid flow. The direction of formation water flow in the Leduc-Cooking Lake aquifer is northeastward at 38^{O}, sub-parallel to the limit of the Killam Barrier Reef (Figure 73), and the hydraulic gradient is approximately ∇H_0 = 0.1% (1 m/km). The slope of the top of the aquifer is ∇E = 0.5% (5 m/km) at 60°, also to the northeast. A driving force ratio (DFR) of 3 indicates that buoyancy is stronger than the natural hydrodynamic drive the in the aquifer. As a result, acid gas will migrate northeastward at approximately 53°. Based on the porosity and permeability values for the Leduc-Cooking Lake aquifer (Table 6) and of acid gas and brine properties (Table 17), an order-of-magnitude analysis shows that the velocity of the updip migrating acid-gas in the far-field of the injection well is on the order of 40 m/year or less (Figure 73).

The subcrop edge of the Leduc-Cooking Lake aquifer, beyond which it is in direct hydraulic communication with the Lower Mannville aquifer, is located at a distance of approximately 150 km (~ 4000 years migration time) from the injection well along the potential acid-gas migration path. Dissolution, dispersion, residual gas saturation and trapping of the acid gas along the migration path make it unlikely that the lateral extent of the acid gas plume would reach the Lower Mannville aquifer. Once in the Lower Mannville aquifer, the acid gas will have to move farther updip along the top of the aquifer for another 150 km, before it will reach the ground surface in the outcrop area of the Lower Mannville aquifer. It is not realistic that this long migration path will ever be completed because of dissolution, dispersion, residual gas saturation and trapping of the acid gas along the migration path.

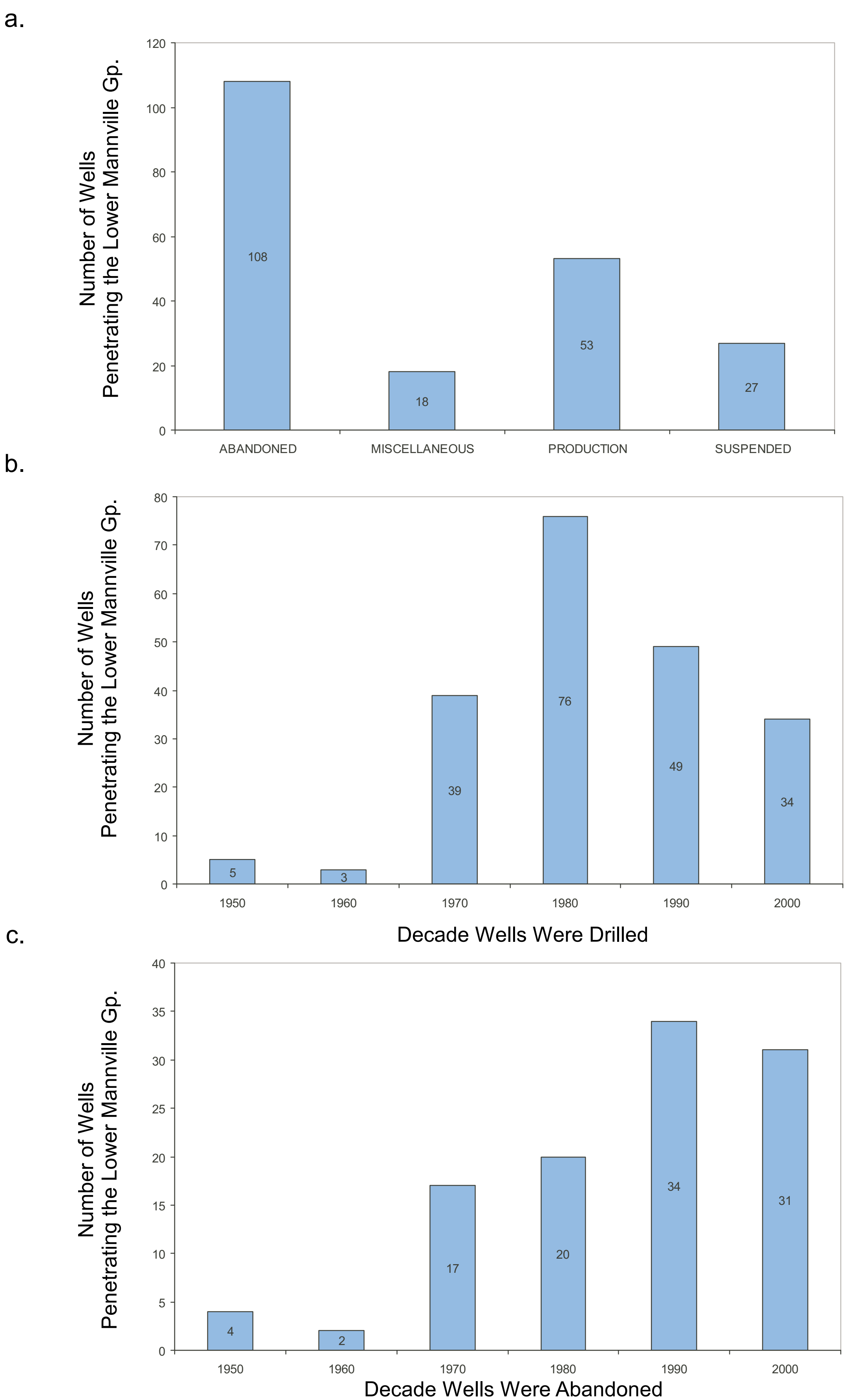


Figure 72. Histograms for wells that penetrate the Lower Mannville Group along the potential acid-gas migration path in the Kelsey area showing: a) well status, b) time of drilling, and c) time of abandonment for abandoned wells.

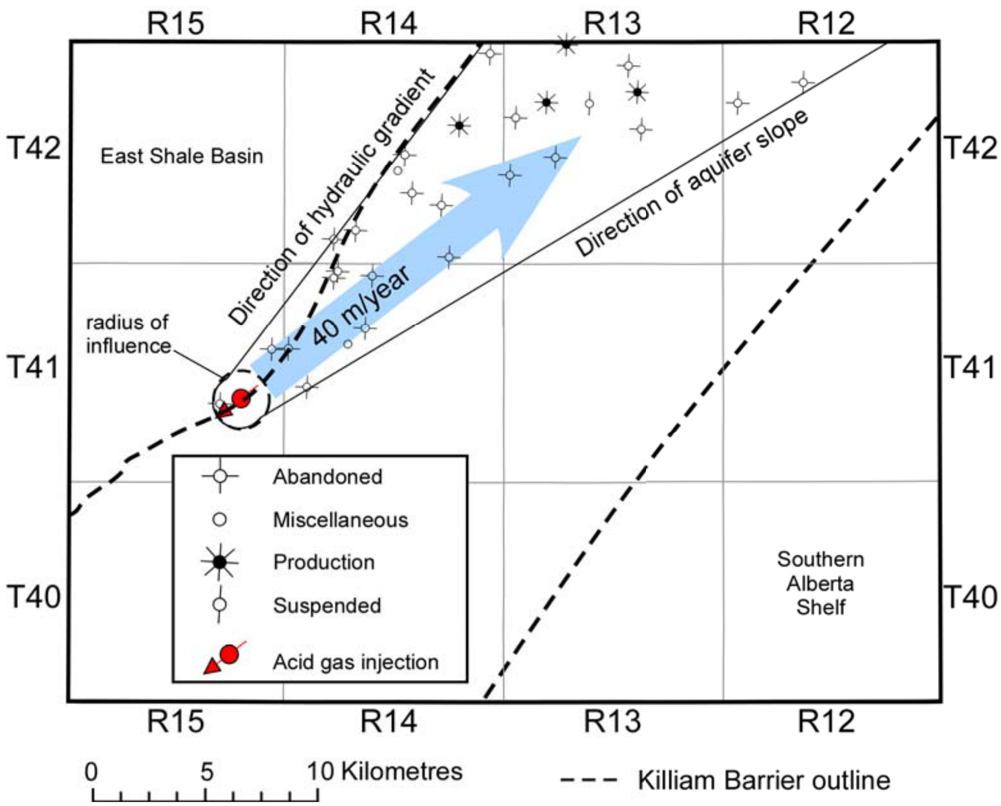


Figure 73. Assessment of long-term acid-gas migration at Galahad, showing location and status of wells along the potential migration path. The blue arrow represents the inferred flow direction of separate-phase acid-gas as a result of the vectorial summation of buoyancy and hydrodynamic drive (Equation 1).

There are no known faults propagating through the sedimentary succession in the Galahad area. Therefore, the only possibility of vertical migration of acid gas into aquifers overlying the Leduc Formation through the natural system is upward leakage through windows in the Ireton aquitard. In the Galahad area, the Ireton Formation shales identified in existing wells have a thickness between 10 and 30 m. The local- and regional-scale hydrogeological assessments show that there are similarities in the pressure regime and formation water chemistry in the Lower Mannville and Leduc-Cooking Lake aquifers, suggesting the possibility of hydraulic communication between the two aquifers. In fact, previous studies have demonstrated that the high-salinity plume in the Lower Mannville aquifer originates from cross-formational flow of Devonian brines (Bachu, 1995; Rostron and Toth, 1995; Anfort *et al*.; 2001; However, the breaches of the Ireton aquitard reported in the literature are all located west (Bashaw), or northwest (Rimbey-Meadowbrook) of the Galahad area, and so far no windows in the Ireton aquitard have been identified in the area of the Killam Barrier Reef and east of it. The succession of additional regional aquitards (Upper Mannville and Colorado) farther up in the stratigraphic column would effectively prevent any leakage to shallow aquifers or the ground surface, even if the Ireton aquitard had windows or was breached by production-induced fractures.

Only 30 wells, the earliest drilled in 1948, penetrate the injection horizon along the potential flow path of the acid gas in the Leduc-Cooking Lake aquifer (Figures 73 and 74), which represent possible leakage conduits to overlying formations. Figure 74 shows the well statistics with respect to status, age, and time of well abandonment. The majority of wells (24) were abandoned or

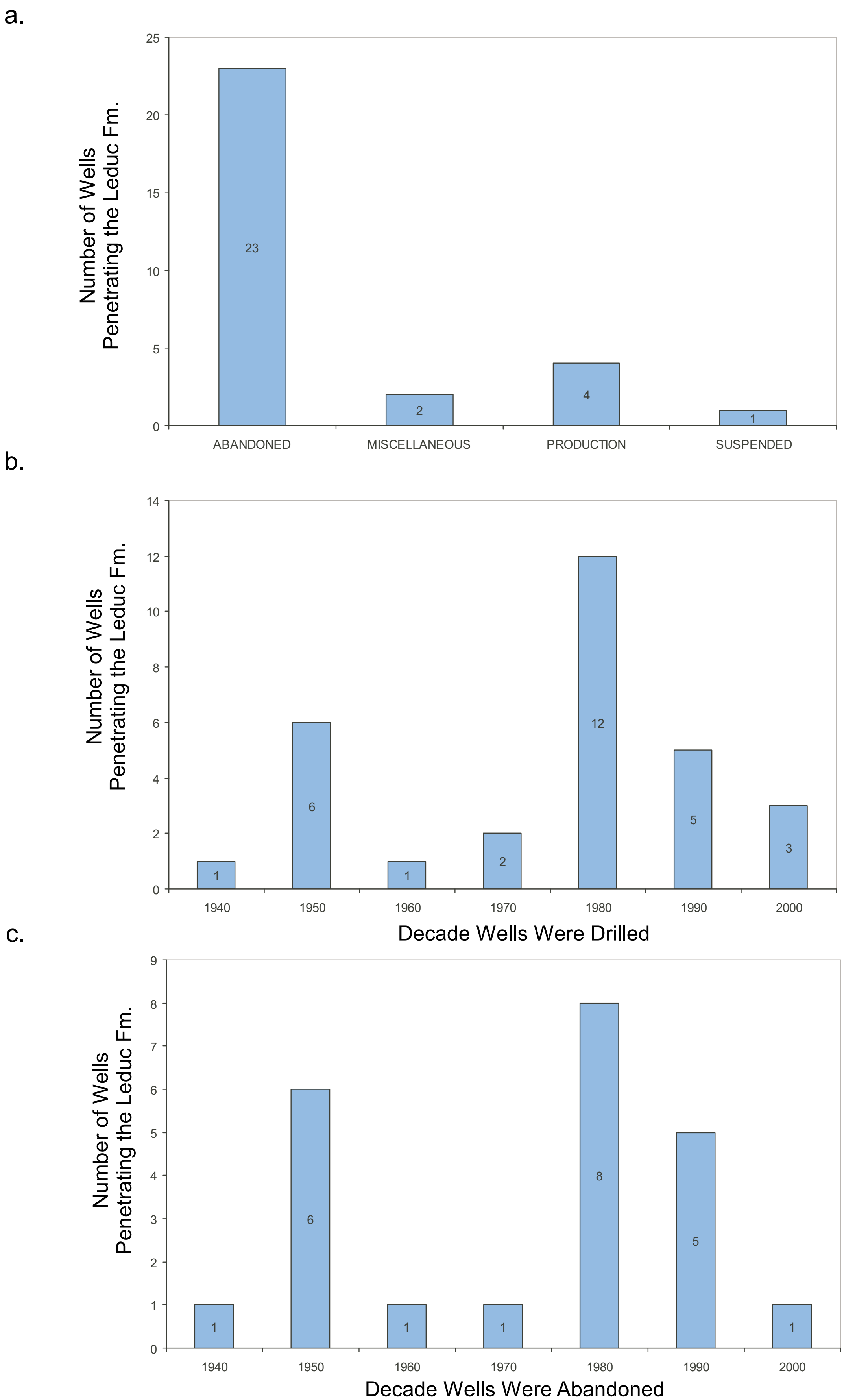


Figure 74. Histograms for wells that penetrate the Leduc Formation along the potential acid-gas migration path in the Galahad area showing: a) well status, b) time of drilling, and c) time of abandonment for abandoned wells.

suspended. The only four producing wells are completed above the injection horizon in the Lower Mannville Group.

6.2.5 Provost - Leduc (Thompson Lake)

At Thompson Lake, acid gas mixed with water was injected into the Leduc-Cooking Lake aquifer from 1995 to 1999 and "dry" acid-gas has been injected since then. A total volume of 85 million cubic metres of acid gas has been injected by the end of 2004. The injection well is located approximately 30 km east of the Galahad operation, at which acid gas is injected into the same aquifer in the central part of the Leduc-Cooking Lake platform. The Thompson Lake injection operation is the biggest in the Provost area with an anticipated total acid-gas injection volume of 160 million cubic meters.

Formation water flow at the Provost-Leduc site is towards the northwest at 49°, with a hydraulic gradient ∇H_0 = 0.1% (1 m/km) (Figure 75). The slope of the aquifer is ∇E = 0.42% (4.2 m/km) at 49° to the northeast. Buoyancy is the slightly more dominant flow-driving mechanism for acid gas migration (DFR = 2), and the flow direction of the acid gas plume will be approximately 22° to the northeast, at a velocity in the order of 6 m/year.

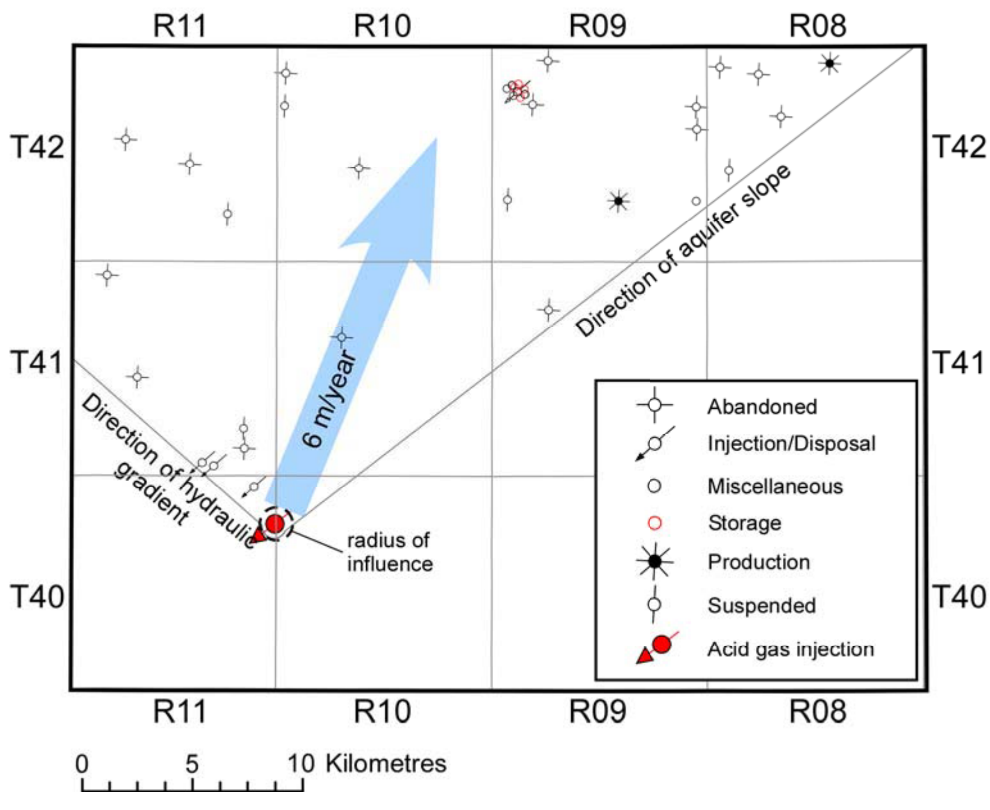


Figure 75. Assessment of long-term acid-gas migration at Thompson Lake, showing location and status of wells along the potential migration path. The blue arrow represents the inferred flow direction of separate-phase acid-gas as a result of the vectorial summation of buoyancy and hydrodynamic drive (Equation 1).

The Ireton aquitard that overlies the Leduc-Cooking Lake aquifer will retard any vertical leakage of acid gas to shallower aquifers. Lateral updip migration within the aquifer will lead to dissolution/trapping/dispersion of the acid gas, and it is unlikely that significant concentrations of acid gas will be detected more than 50 km away from the injection site. The nearest outcrop of the Leduc-Cooking Lake aquifer in the updip direction is approximately 125 km to the northeast, and covering that distance theoretically would take an acid gas plume in the order of 20,000 years.

Forty-three wells, the oldest drilled in the 1950s, penetrate the injection horizon along the potential flow path of the acid gas in the Leduc-Cooking Lake aquifer (Figures 75 and 76), and represent possible leakage conduits to overlying formations. Figure 76 shows the well statistics with respect to status, age, and time of well abandonment. There is no production from the injection horizon, the Leduc Formation. In addition to the acid-gas injection well, one well disposes of production water into the Leduc Formation, approximately 22 km to the northeast. In this area, there are four wells that inject LPG into Elk Point strata for storage purposes. The three production wells are completed in the Cretaceous Viking Formation and water disposal occurs through three wells into the Lower Mannville Group. Of the 16 abandoned wells, five have been abandoned before the 1970s.

6.2.6 Provost - Keg River

The Provost-Keg River acid-gas injection operation is located in the Hansman Lake area and acid gas injection into the Keg River Formation commenced in 1995. A total volume of 56 million cubic metres of acid gas has been injected by the end of 2004. The direction of formation water flow in the Keg River aquifer, as determined from a limited amount of data in the regional-scale study area, is approximately northeastward at 66°, and the hydraulic gradient is ∇H_0 = 0.05% (0.5 m/km). The slope of the top of the aquifer is ∇E = 0.27% (2.7 m/km) at 36° to the northeast. The hydraulic gradient is very small due to the vertical hydraulic isolation from the ground surface and the long distance to the outcrop of the Keg River aquifer (~300 km), resulting in a weak influence of topography on formation water flow. Consequently, the DFR of 2.3 indicates that buoyancy is stronger than the natural hydrodynamic drive in the aquifer, and acid gas will migrate dominantly northeastward at approximately 30° at a velocity in the order of 1 m/year. At this velocity, it would take approximately 300,000 years for any acid gas to reach the subcrop of the Keg River aquifer below the Lower Mannville aquifer, which is located at a distance of approximately 300 km from the injection well near eastern edge of the Alberta Basin. Besides dissolution, dispersion and residual saturation, the undulating surface of the top of the Keg River aquifer forms many traps along the potential flow path of the acid gas, making it improbable that any acid gas will ever reach the subcrop edge.

The local and regional hydrogeological assessment has shown that the Prairie Formation forms an effective aquitard at the top of the Keg River aquifer, preventing natural vertical leakage to overlying aquifers. Low-permeability sediments in the Ireton Formation, Upper Mannville and Colorado groups provide additional vertical barriers to flow to shallow aquifers containing potable groundwater or the ground surface. Except for the acid-gas injection well, there are no wells penetrating the Keg River aquifer along the potential migration path.

6.3 Comments on Well Abandonment and Potential Leakage through Wells

Open-hole wells are abandoned by plugging every aquifer and producing formation in the succession above perforations, to avoid cross-formational flow, such that further leakage through these wells is unlikely unless cement plugs are completely degraded. In the case of open-hole abandoned wells, further leakage of acid gas is stopped by the succession of plugs. Cement degradation takes place in the presence of both formation water and acid gas; if the acid gas forms an isolating layer at the bottom of the plug that stops any contact between cement and

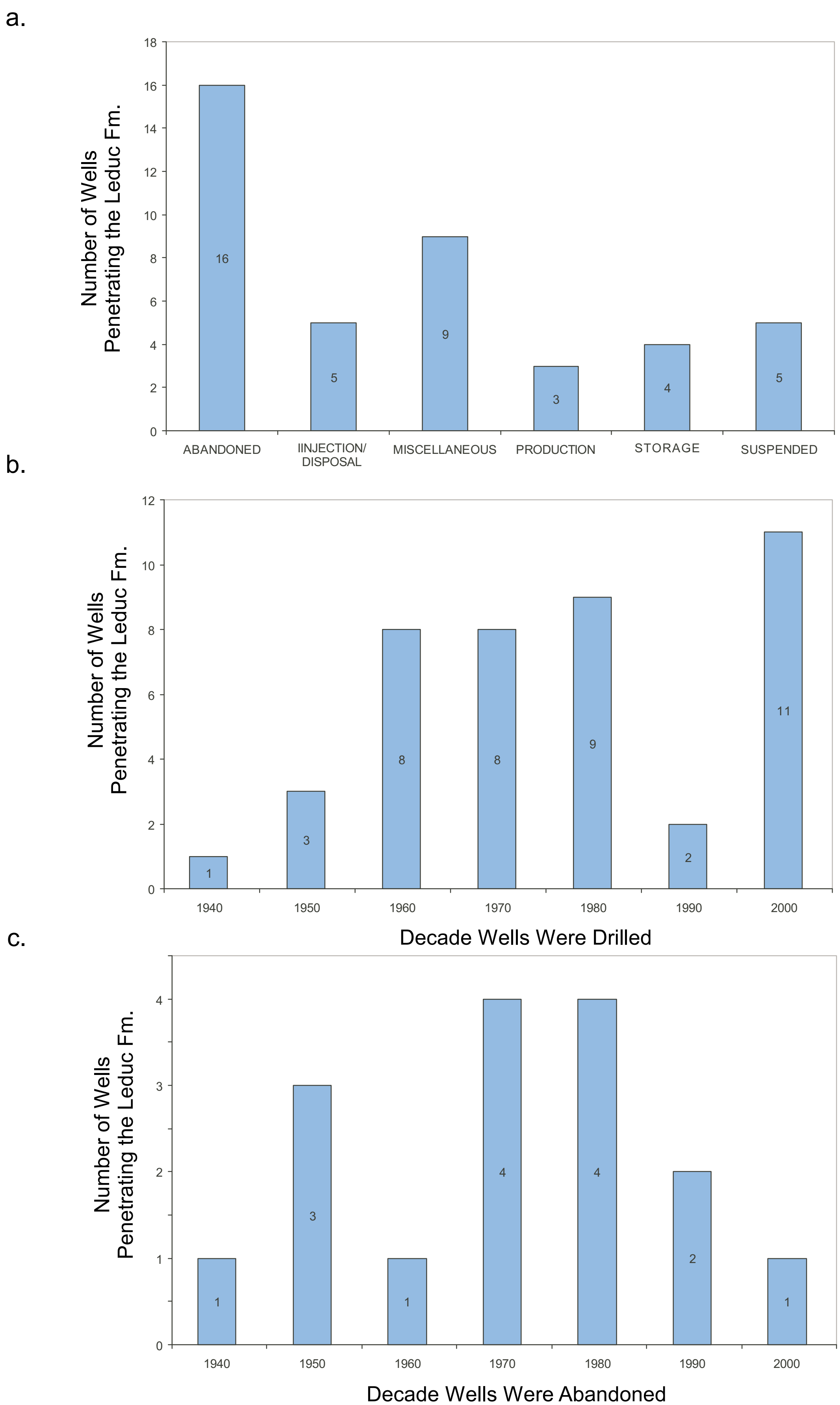


Figure 76. Histograms for wells that penetrate the Leduc Formation along the potential acid-gas migration path in the Thompson Lake area showing: a) well status, b) time of drilling, and c) time of abandonment for abandoned wells.

formation water, then further degradation will not occur (Scherer *et al*., 2004). Any leaked acid gas will likely spread into the aquifer that is isolated by that plug, where it will dissolve. The rate of leakage is relatively small (flow through porous media) and likely decreases from one aquifer to another, similar to the “elevator model” in the case of water leakage (Nordbotten *et al.*, 2004b). Cased wells are usually abandoned by emplacing a plug just above perforations, and another one close to surface. If acid gas corrodes the casing, leaks inside casing and degrades the cement plug, it will migrate upwards all the way to the top plug. Along the way, the acid gas will decompress and reach gaseous phase at the top. Accumulation of acid gas with water present will have a corrosive effect on casing, such that acid gas leakage may subsequently occur directly into shallow groundwater close to the surface. In this case, the well tubing provides an open-flow conduit that bypasses the entire succession of aquifers and aquitards above the injection unit with their retarding effect. From this point of view, leaky cased wells represent a greater risk than open-hole abandoned wells.

In all the cases, poor-quality completion in existing or future wells may provide a pathway for upward leakage from the injection reservoir or from any place that an acid gas plume may reach in the future. However, the time scale and magnitude of the degradation cannot be assessed with the current data, knowledge and methods. Also, leakage to the surface through abandoned wells at the six acid-gas injection sites, now or in the future, should not be a concern, even if some wells are improperly abandoned, for the following reasons:

- Leaky wells affect each other (pressure interference), such that the leakage rate per well is significantly reduced (Nordbotten *et al*., 2004b).
- The leakage rate is again significantly reduced when other aquifers containing high-salinity brine overly the injection unit, because these aquifers serve as receptors for most of the leaked gas (Nordbotten *et al*., 2004b) before it can reach shallow freshwater aquifers or the ground surface.
- Any acid gas that would leak from the injection horizon into overlying or underlying aquifers will disperse, diffuse and mix further with the formation water in that aquifer.
- Additionally, in the cases of sour water injection at Bellshill Lake and Hansman Lake, the respective injection reservoir is still under production. Thus, the injected acid gas will not have enough pressure drive to reach the surface but rather be captured in the nearest producing well, at least during the active production life of the reservoir.

7 Conclusions

The experience gained since the start of the first acid-gas injection operation in Canada in 1989 shows that, from an engineering point of view, acid gas disposal is a well-established technology. By the end of 2004, close to 2.5 Mt CO_2 and 1.8 Mt H_2S have been successfully injected into deep hydrocarbon reservoirs and saline aquifers in Alberta and British Columbia. A major issue that has not been addressed is the containment and long-term fate of the injected acid gas.

Injection of acid gas in the Provost area in southeast Alberta takes place at six sites into four different stratigraphic intervals. Dry acid gas is injected into the deep saline Middle Devonian Keg River aquifer at Provost. At Thompson Lake and Galahad, dry acid gas is injected into the Upper Devonian Leduc-Cooking Lake aquifer, and into the Upper Devonian Wabamun aquifer at Kelsey. At Hansman Lake and Bellshill Lake, the acid gas was or is mixed with disposal water at the surface and injected into Lower Mannville oil reservoirs. By the end of 2004, more than 290 kt CO_2 and 55 kt H_2S were injected into deep geological formations in the Provost area.

If only the natural setting is considered, including geology and flow of formation waters, the basin- and local-scale hydrogeological analyses indicate that injecting acid gas into these deep geological units in the Provost area is basically a safe operation with no potential for acid gas migration to shallower strata, potable groundwater and the surface. At Bellshill Lake and Hansman Lake, where sour water is or was injected into currently producing Lower Mannville reservoirs, the injected water will remain within the respective pool outlines and will partly be recycled in the injection/production cycle. In the cases of dry acid-gas injection, the acid gas plume will likely be reduced by dissolution, dispersion, residual gas saturation and trapping along the migration pathway and therefore not reach the overlying aquifers. In the unlikely event of further migration, it would take in the order of 5000 years before acid gas could be detected in the overlying Lower Mannville aquifer at Galahad and Thompson Lake, where acid gas is injected into the Leduc Formation. Once in the Lower Mannville aquifer, the acid gas theoretically would have to move farther updip along the top of the aquifer for another 150 km (~15,000 years), before it would reach the ground surface in the outcrop area of the Lower Mannville aquifer. Although migration of acid gas from the Wabamun into the Lower Mannville aquifer at Kelsey is very likely, the acid gas would have to complete an even longer migration path before it reaches the area of Lower Mannville Group outcrop. Ultimately, it is not realistic that this long migration path will ever be completed because of dissolution, dispersion, residual gas saturation and trapping of the acid gas along the migration path. At Provost-Keg River, vertical migration will be prevented by the effective aquitard characteristics of the Prairie Formation. In addition, low-permeability sediments of the Beaverhill Lake Group, the Ireton Formation and the Colorado Group provide additional vertical barriers to flow to shallow aquifers.

The entire stratigraphic interval from the Keg River Formation to the Lower Mannville Group is overlain by at least one thick shale sequence, the Colorado Group. There are many barriers to acid gas migration from an injection zone into other strata, and the flow process, if it will ever happen, would take an extremely long time, on a geological time scale. Any acid gas plume would disperse and dissolve in formation water during flow on such large time and spatial scales.

Based on available data, it seems that there is no potential for acid gas leakage through fractures. However, the possibility for upward leakage of acid gas exists along wells that were improperly completed and/or abandoned, or along wells whose cement and/or tubing has degraded or may degrade in the future as a result of chemical reactions with formation brine and/or acid gas. The Provost area has a very high well density, the majority of the wells penetrating hydrocarbon-bearing strata in the Lower Mannville Group. Wells in the Provost area were drilled, and successively abandoned, as early as the late 1940s and, considering the old age, damage to or improper well completion is very likely in some cases. No leakage has been detected and reported to date, however, the potential for this occurring in the future should be considered by both operators and regulatory agencies.

These conclusions are based on a qualitative hydrogeological analysis in the sense that the geological and hydrogeological data were interpreted within the framework of the most current knowledge about the Alberta Basin and its contained fluids. No quantitative analysis based on numerical modeling was performed because, to the best knowledge of the authors, no such models are available. Predictive numerical models of acid gas injection and flow, if not already in existence, should be developed and used to validate the qualitative hydrogeological analysis presented in this report. Geochemical and geomechanical effects on reservoir rock and caprock should be assessed to confirm integrity. The potential for and risk of leakage through existing wells should be better assessed. In addition, a monitoring program would support and provide feedback to the analysis and modelling, and greatly enhance the confidence in the safety of the operation.

Extension of this type of analysis to other current and future disposal sites will lower risk and increase the public trust in the potential and safety of geological sequestration of acid and greenhouse gases. Ideally, a thorough program for predicting the long-term fate of the injected acid gas should contain the following major components:

- a hydrogeological analysis of the injection site at various scales, from site-specific to regional, to provide the context, understanding and necessary data for a qualitative assessment;
- numerical modeling for predicting possible migration and/or leakage paths and corresponding time scales for the injected acid gas;
- monitoring of the acid gas plume, to validate and update the numerical model; and
- continuous updating of the hydrogeological and numerical models as new data are acquired.

Currently there are no adequate numerical models that could properly simulate the fate of the acid gas injected in deep geological formations. In addition, monitoring programs are expensive, and, in the absence of forward-simulating models, may not provide the necessary information. However, the hydrogeological analysis, the first step for understanding the fate of the acid gas, can be easily implemented for all acid-gas injection sites, particularly in the case of basins with a wealth of data such as the Alberta Basin.

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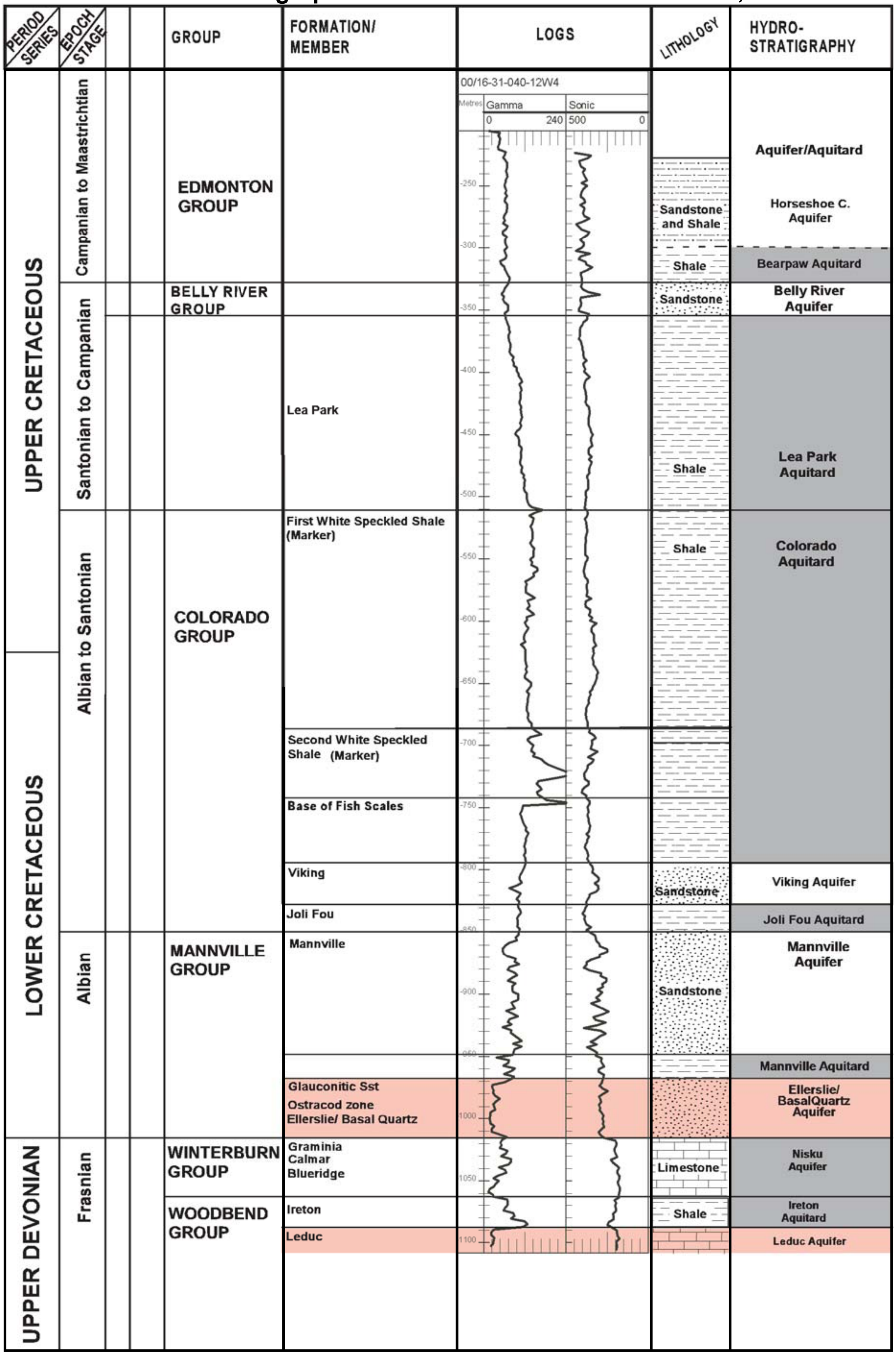
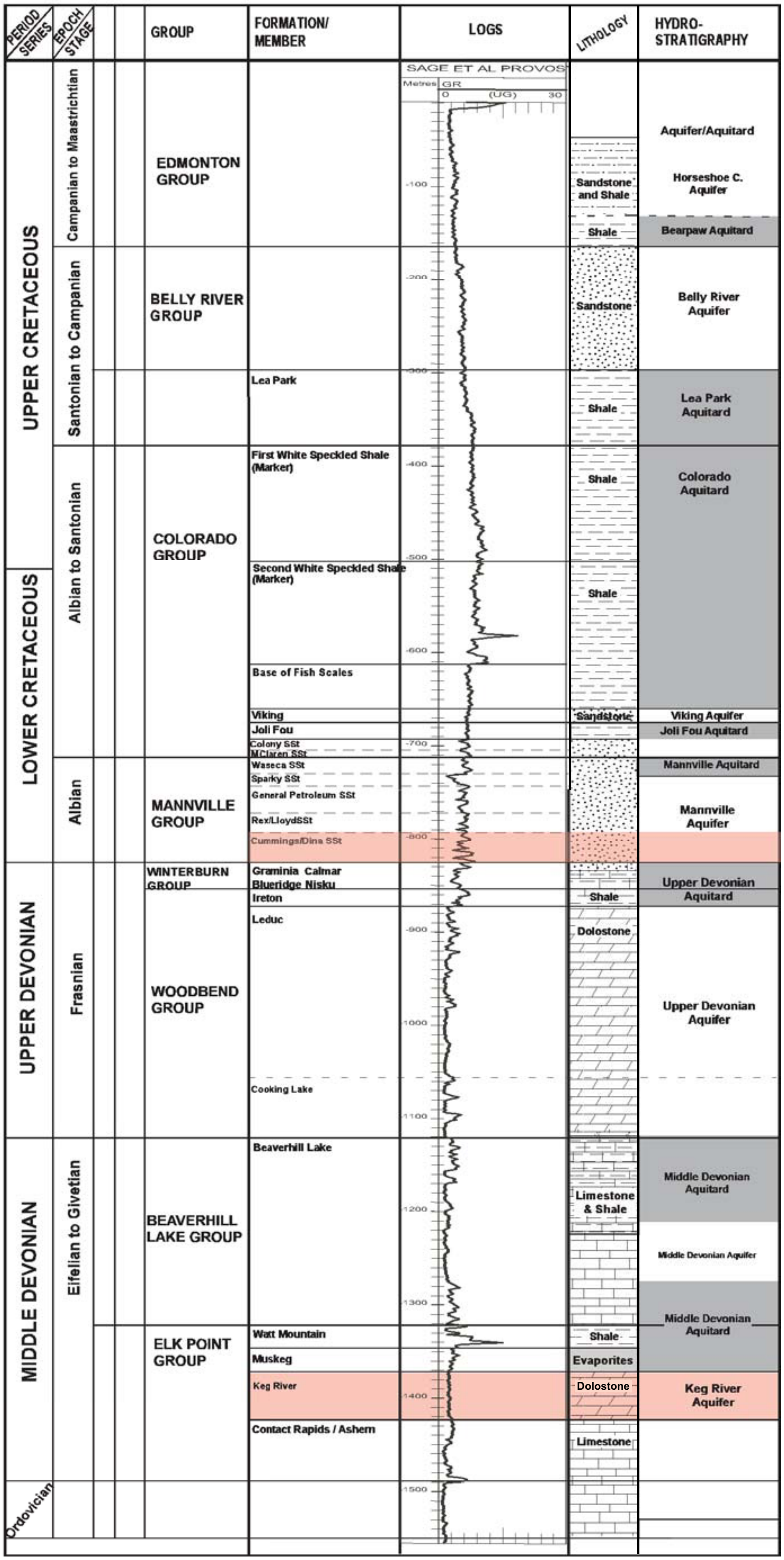
Appendix 1

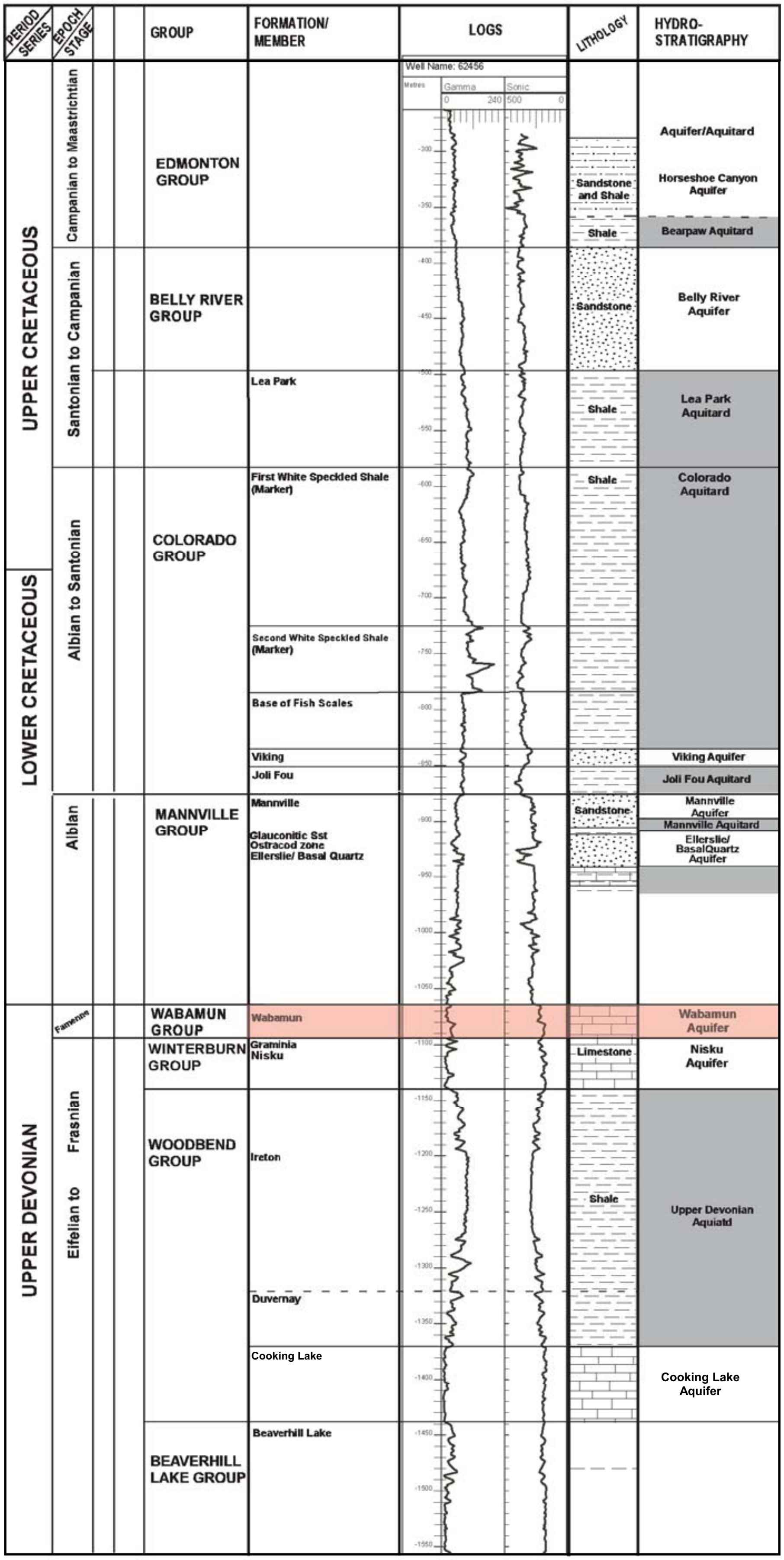
Downhole Stratigraphic Model for the Bellshill Lake Area, Alberta



Downhole Stratigraphic Model for the Hansman Lake Area, Alberta



Downhole Stratigraphic Model for the Kelsey Area, Alberta



Downhole Stratigraphic Model
for the Galahad and Thompson Lake Areas, Alberta