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ERCB

Subsurface Characterization of Acid-Gas Injection Operations in the Peace River Arch Area

Energy Resources Conservation Board

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Alberta Geological Survey

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This report is the AGS release of a 2007 client report prepared for the Acid Gas Management Committee, a consortium of provincial and federal agencies and industry partners.

Executive Summary

Injection of acid gas in the Peace River Arch area occurs at eleven operations in three major stratigraphic units, the Upper Devonian Leduc Formation and Wabamun Group, the Permo-Mississippian Belloy and Kiskatinaw formations, and the Triassic Halfway Formation. By the end of 2006, approximately 340 million cubic metres of acid gas were injected into deep geological formations in the Peace River Arch area.

If only the natural setting is considered, including geology and flow of formation waters, the regional- and local-scale hydrogeological analyses indicate that injecting acid gas into these deep geological units in the Peace River Arch area is a safe operation with no potential for acid-gas migration to shallower strata, potable groundwater and the surface. At Dunvegan, Eaglesham, Gordondale (Halfway), Mirage, Normandville, Parkland, and Puskwaskua, injection occurs or took place into depleted hydrocarbon reservoirs. By regulation, downhole pressures will not exceed the respective initial reservoir pressures and the injected gas will remain within the respective pool outlines. At Mirage and Gordondale-Halfway, acid gas was injected into currently producing Halfway reservoirs, which will partly be recycled in the injection/production cycle. In the cases of acid-gas injection into deep saline aquifers (Gordondale-Belloy, Mulligan, Pouce Coupe, Rycroft and Wembley), the extent and migration of the acid-gas plume will likely be limited by dissolution, dispersion, residual gas saturation and trapping along the migration pathway and therefore not reach the overlying aquifers.

The entire stratigraphic interval from the Leduc Formation to the Halfway Formation is overlain by at least one contiguous thick shale sequence, the Smoky Group. Other aquitards (i.e., Wilrich, Fernie, Charlie Lake, Montney, Banff-Exshaw) form additional barriers to acid-gas migration from the various injection zones 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.

Tectonics greatly affected the sedimentary framework, particularly the Paleozoic succession, in the Peace River Arch area. The main tectonic activity occurred during the late Carboniferous, resulting in thick Mississippian to Permian sediment accumulation in the area of the Dawson Creek Graben Complex. Under the present-day stress regime, faults that are present in the various local-scale study areas do not appear to act as fluid conduits through aquitards overlying the respective injection horizons. However, the displacement of strata along faults that are present near injection wells results in a partial lateral confinement of acid-gas within injection intervals. Based on available data, it seems that there is no potential for acid gas leakage through faults and 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 Peace River Arch area has a high well density and the wells penetrate hydrocarbon-bearing strata down to the Granite Wash overlying the Precambrian basement. Wells in the Peace River Arch area were drilled, and successively abandoned, as early as the late 1950s 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. However, recent modelling results published in the literature suggest that after 10,000 years the maximum radius of an acid-gas plume is in the order of 5 km. Predictive numerical models of acid-gas injection and flow should be used in the future to validate the qualitative hydrogeological analysis presented in this report. Geochemical and geomechanical effects on reservoir rock, caprock and faults should be assessed to confirm integrity. The potential for and risk of leakage through existing wells and faults 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.

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Dr. Dong Chen constructed the majority of the local-scale cross-sections by interpreting geophysical well logs and created a set of six downhole stratigraphic models. Her extensive knowledge of the stratigraphy in the Peace River Arch area was a great benefit for understanding the geology of the Triassic to Mississippian succession in this area.

Dr. Nigel Atkinson contributed in the setup of databases and in the modelling of the stratigraphic framework.

Dr. Dinu Pana provided scientific advice in the interpretation of faults and their affect on fluid flow.

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Dan Magee provided graphic support and Maryanne Protz was in charge of the final assemblage and layout of the manuscript

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1 Introduction

Over the past 17 years, 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, 48 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 eleven operations that are the subject of this report (Dunvegan, Eaglesham, Gordondale, Mulligan, Normandville, Parkland, Pouce Coupe, Puskwaskua, Rycroft, and Wembley) form the cluster in the Peace River Arch area and inject acid gas into Upper Devonian to Triassic 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 (Gordondale-Halfway and Gordondale-Belloy), or has different compositions (i.e., dry gas, acid gas mixed with 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 in west-central Alberta, the Edmonton and Provost areas in central Alberta, and in northeastern British Columbia (Bachu *et al*., 2003a, b, Buschkuehle and Michael, 2005, Michael and Buschkuehle, 2005; see Figure 1 for location of study areas). The subsurface characterization of the acid-gas injection operations in the Peace River area will help to address various issues that relate to the disposal and/or sequestration of acid and greenhouse gases, specifically into faulted Devonian to Triassic strata in west-central Alberta and eastern British Columbia. The characterization is based on reservoir-scale data and information submitted by the operators to the EUB and BCEM, on basin-scale work performed at the Alberta Geological Survey (AGS) during the last 5 years, and on local and reservoir-scale work performed by the AGS specifically for this report.

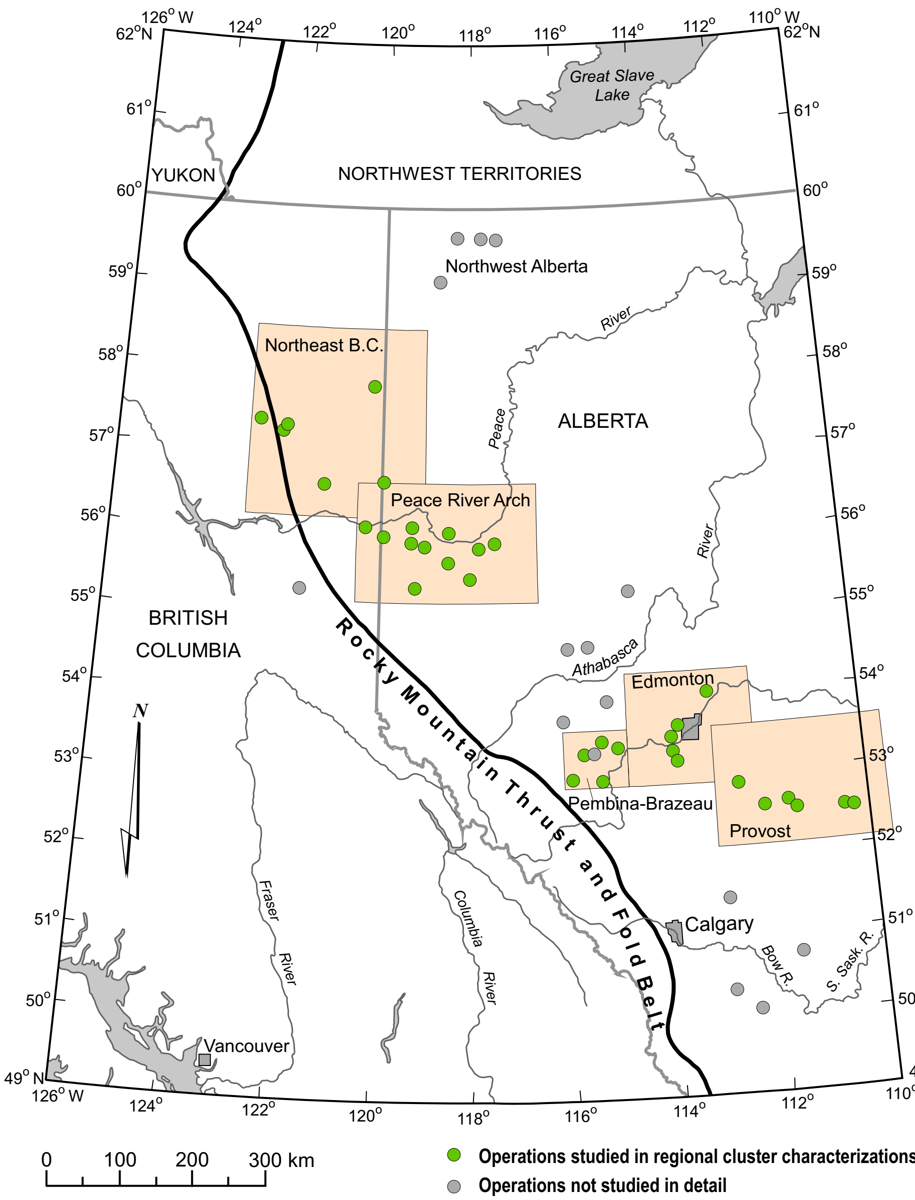


Figure 1. Location of acid-gas injection operations in the Alberta Basin, Canada, at the end of 2006.

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 Directive 65 (revised in December 2006) 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).

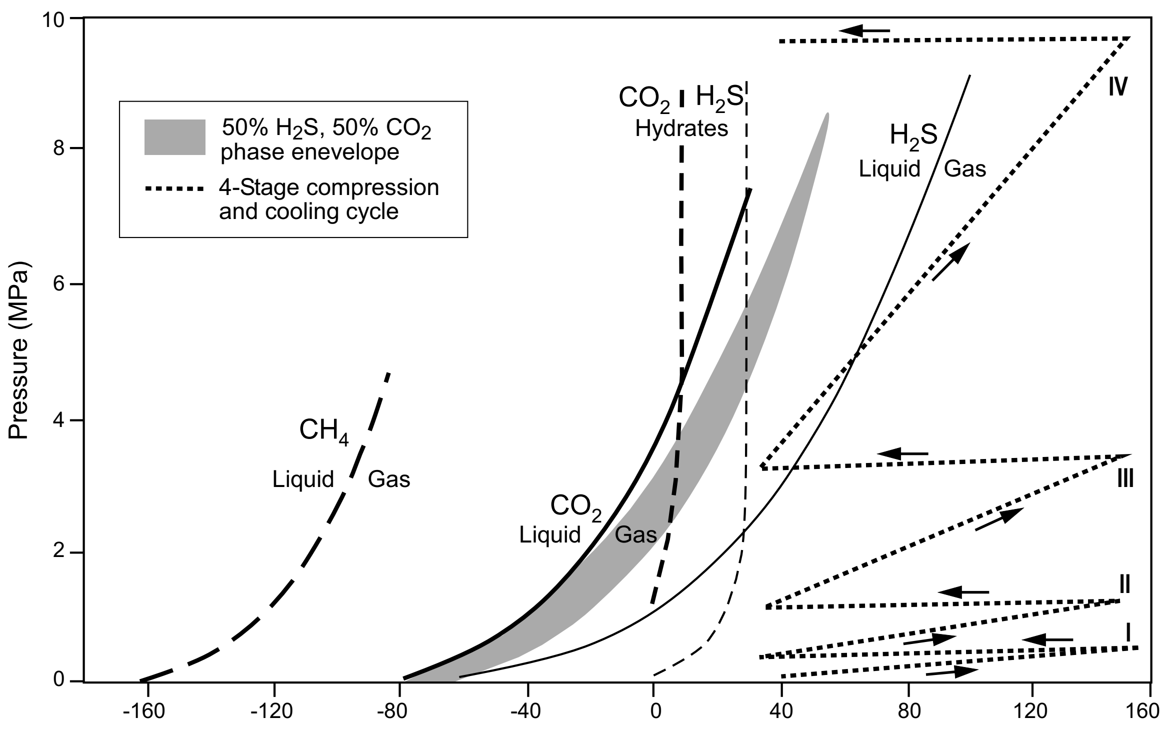


Figure 2. Phase diagrams for methane (CH_4), carbon dioxide (CO_2), hydrogen sulphide (H_2S) and a 50%-50% acid gas mixture; hydrate conditions for CO_2 and H_2S (after Wichert and Royan, 1996, 1997). A four-stage compression and cooling cycle is also shown.

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).

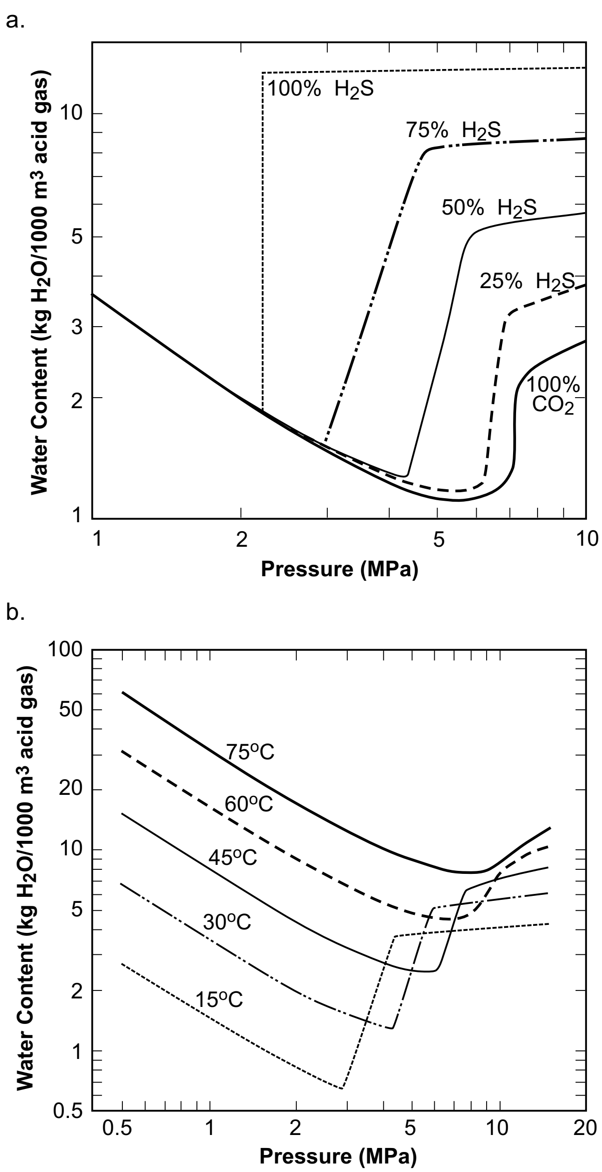


Figure 3. Solubility of water in acid gas as a function of pressure for: a) different acid-gas compositions (CO_2 and H_2S) at 30° C, and b) different temperatures for an acid gas with a composition of 49% CO_2, 49% H_2S and 2% CH_4 (see also Lock, 1997; Wichert and Royan, 1996, 1997).

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;
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 bottomhole 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 Peace River Arch Area

The eleven acid-gas injection operations, which are the subject of this report, are located in the west-central 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 west-central Alberta and eastern British Columbia (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 (1995, 1997, 1999).

The injection targets in the Peace River Arch area are: a) the Devonian Woodbend Group (Leduc Formation, one site), b) the Devonian Wabamun Group (two sites), c) the Carboniferous Stoddart Group (three sites), d) the Permian Belloy Formation (four sites), and the Triassic Halfway Formation (two sites) (Figure 4). Therefore, the Woodbend to Triassic strata 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 bounded by the Rocky Mountain Trench to the west and southwest, the Tathlina High to the north and the Canadian Precambrian Shield to the

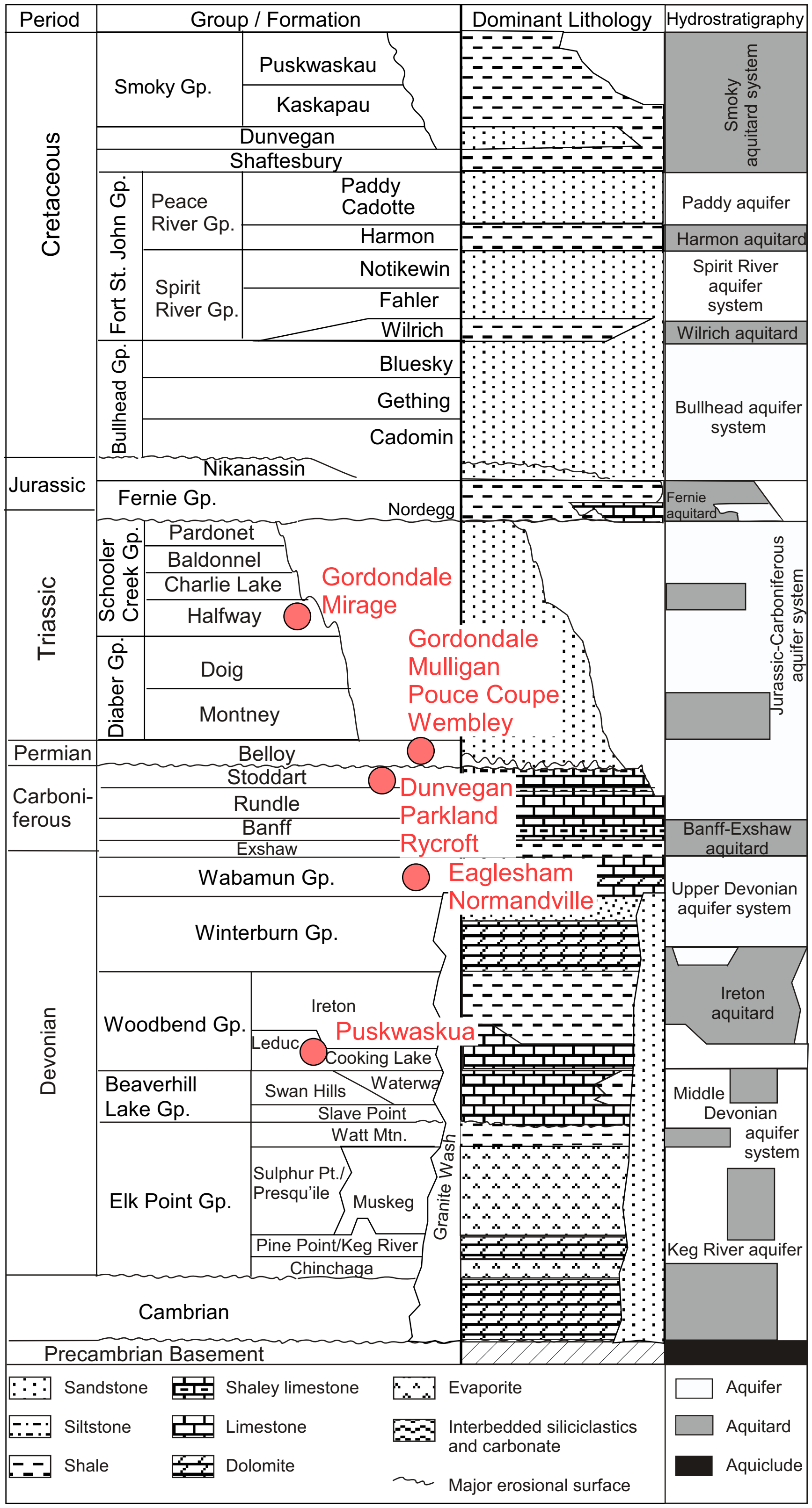


Figure 4. Basin-scale stratigraphic and hydrostratigraphic delineation and nomenclature as well as general lithology for the Peace River Arch area. Acid-gas injection horizons are indicated by red circles.

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 stratigraphic and hydrostratigraphic nomenclature and delineation for the entire sedimentary succession in the Alberta Basin 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 southeastern Alberta 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.

A Middle Devonian interbedded succession of low-permeability anhydritic red beds and carbonates, halite and argillaceous carbonates of the Lower Elk Point Group overlies the Cambrian units or Granite Wash detritus, and forms the Elk Point aquitard system. The overlying platformal and reefal carbonates of the Upper Elk Point Group Keg River Formation form the Keg River aquifer. This unit is overlain over most of the basin by the thick evaporites of the Prairie Formation (Muskeg Formation), followed by the shales of the Watt Mountain Formation, which together form the Prairie aquitard system. In the northern part of the Alberta Basin, the time-equivalent Sulphur Point/Presqui'ile Barrier reef complex forms a carbonate aquifer on top of the Keg River aquifer. 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.

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.

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 5), 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 5), 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.

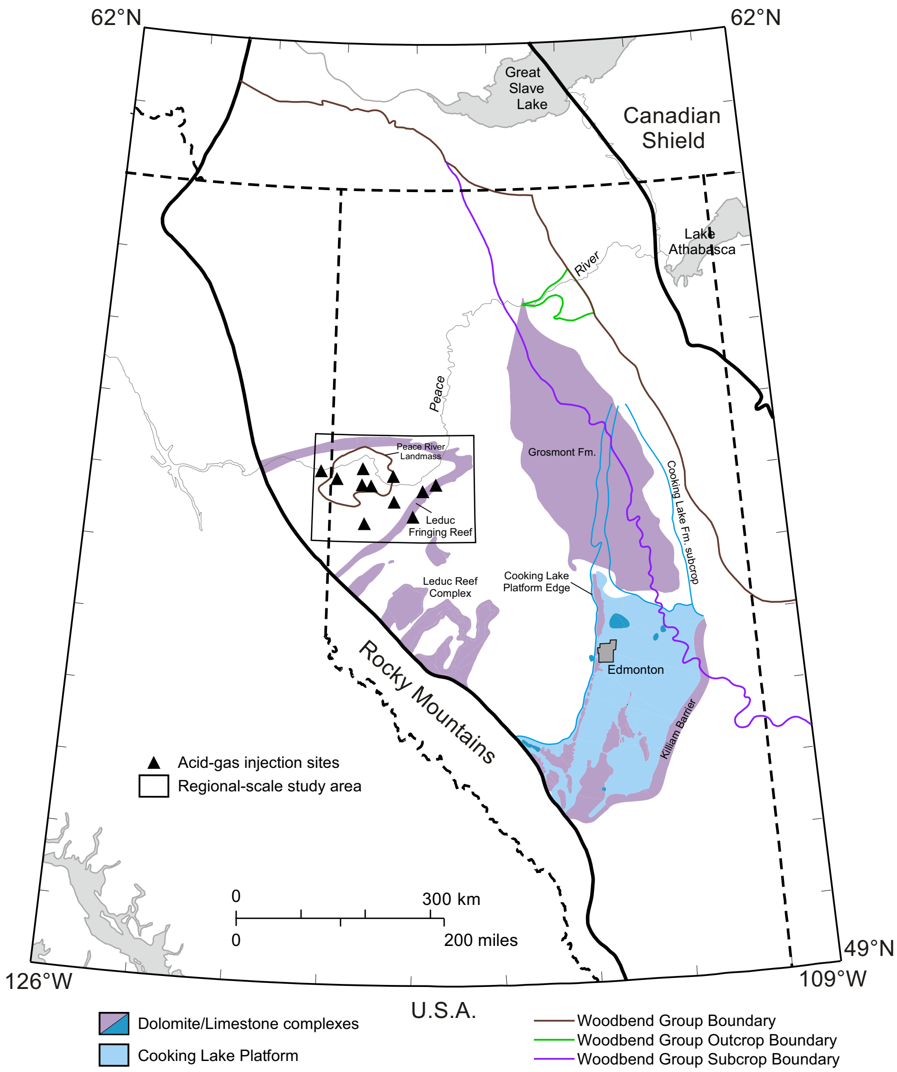


Figure 5. Depositional and erosional boundaries of the Woodbend Group, and outlines of Cooking Lake platform carbonates, Leduc Formation reefs and Grosmont Formation platform carbonates.

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 6) 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 (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 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 unconformably deposited on top of the Wabamun Group during the Late Devonian to Early Mississippian and form the base of the Carboniferous succession. The Carboniferous comprises three main lithofacies associations (Richards *et al*., 1994) (Figure 7). The lower association is represented by interbedded shales and carbonates of the Banff Formation, which was deposited in a basin to slope environment, generally thickening to the southwest (basinward). Upward and northwestward, these basin and slope deposits develop into a second assemblage of platform and ramp carbonates of the Rundle Group. The upper lithofacies association consists of mixed siliciclastics and carbonates of the Stoddart Group, which were deposited in a slope to continental setting.

The Permian succession unconformably overlies in most places the Carboniferous strata and consists generally of marine carbonaceous, phosphatic and dolomitic sandstones. Permian sediments were deposited in a shallow-marine shelf setting within the Ishbel Trough, the Liard Sub-basin (Ishbel Group), and in the Peace River Embayment (Belloy Formation) (Figure 8). The depositional extent of Permian sediments is similar, yet slightly larger, to that of the underlying Carboniferous Stoddart Group (Figure 7). This is the result of the tectonic setting during the Permian, where the Stoddart Group sediments

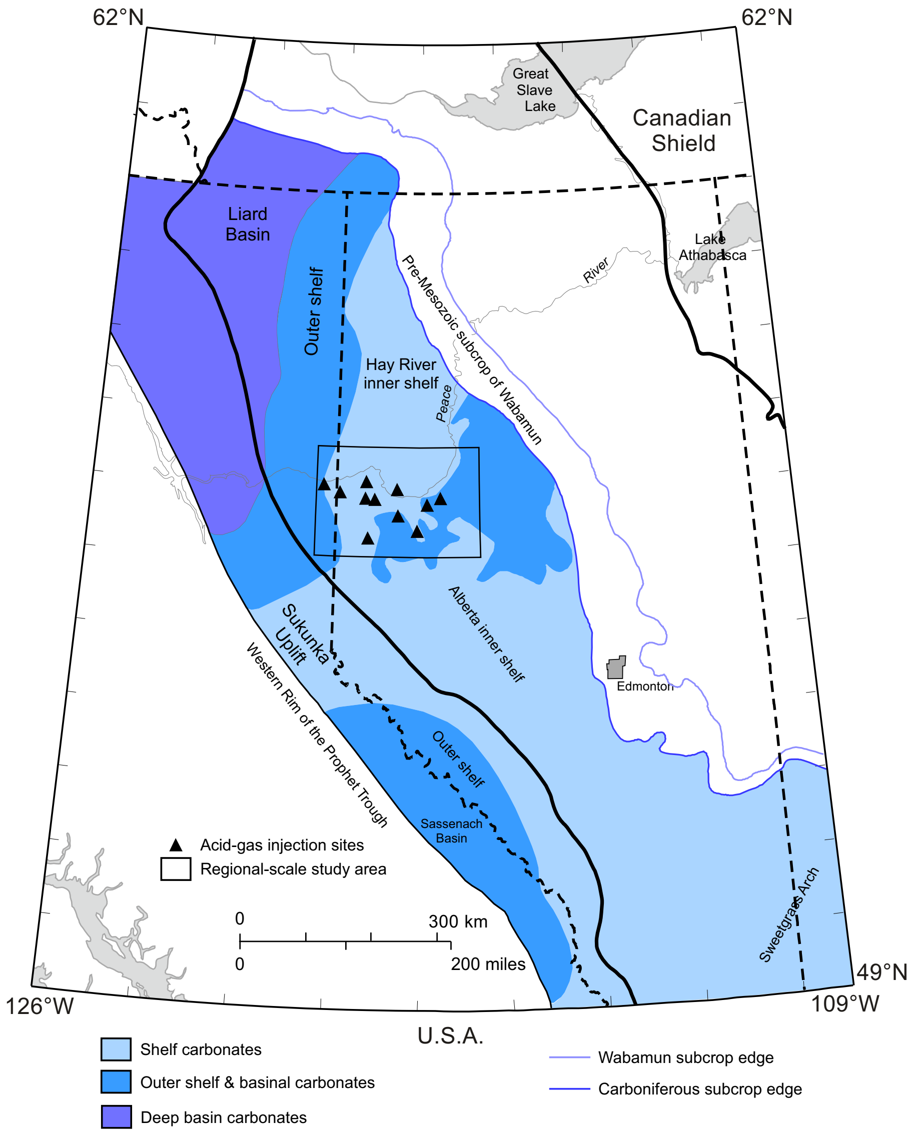


Figure 6. Physiography and tectonic elements of the Wabamun Group in the Alberta Basin.

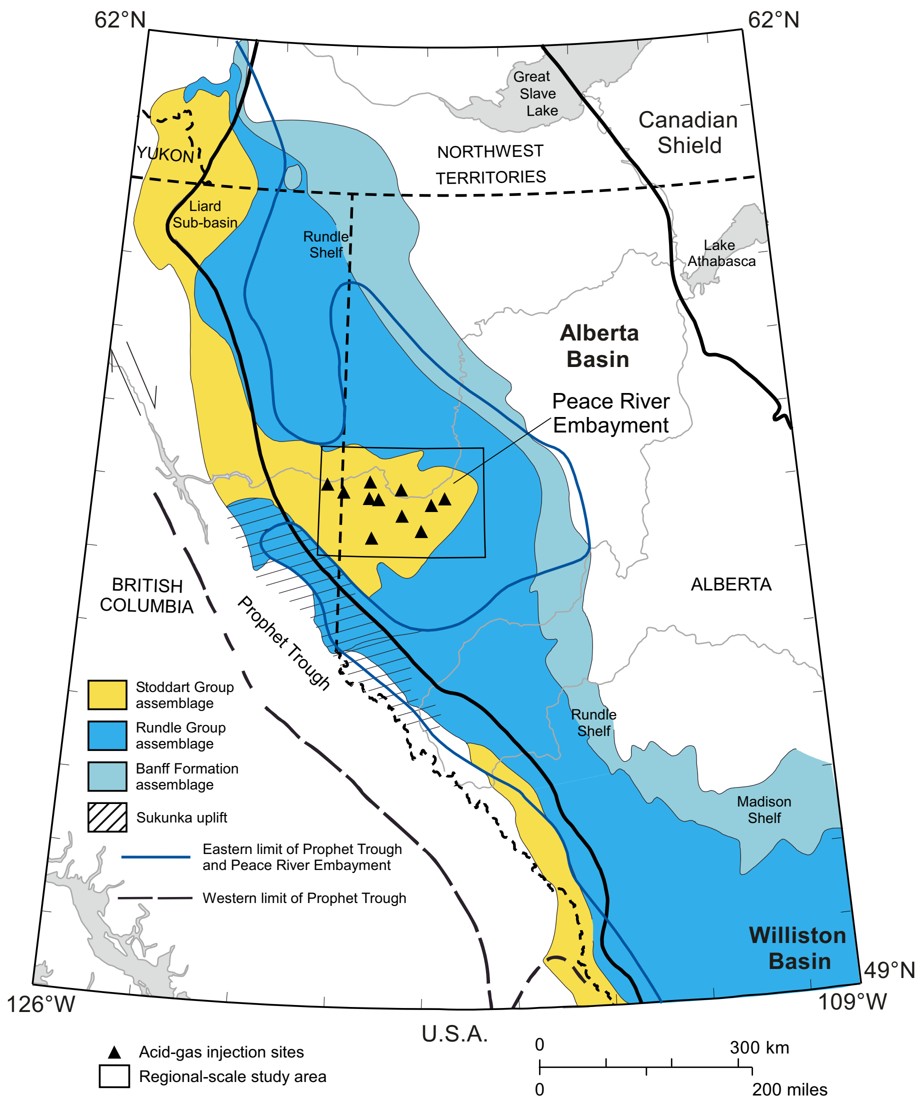


Figure 7. Tectonic elements and Carboniferous lithofacies assemblages in the Alberta Basin (modifies from Richards et al., 1994).

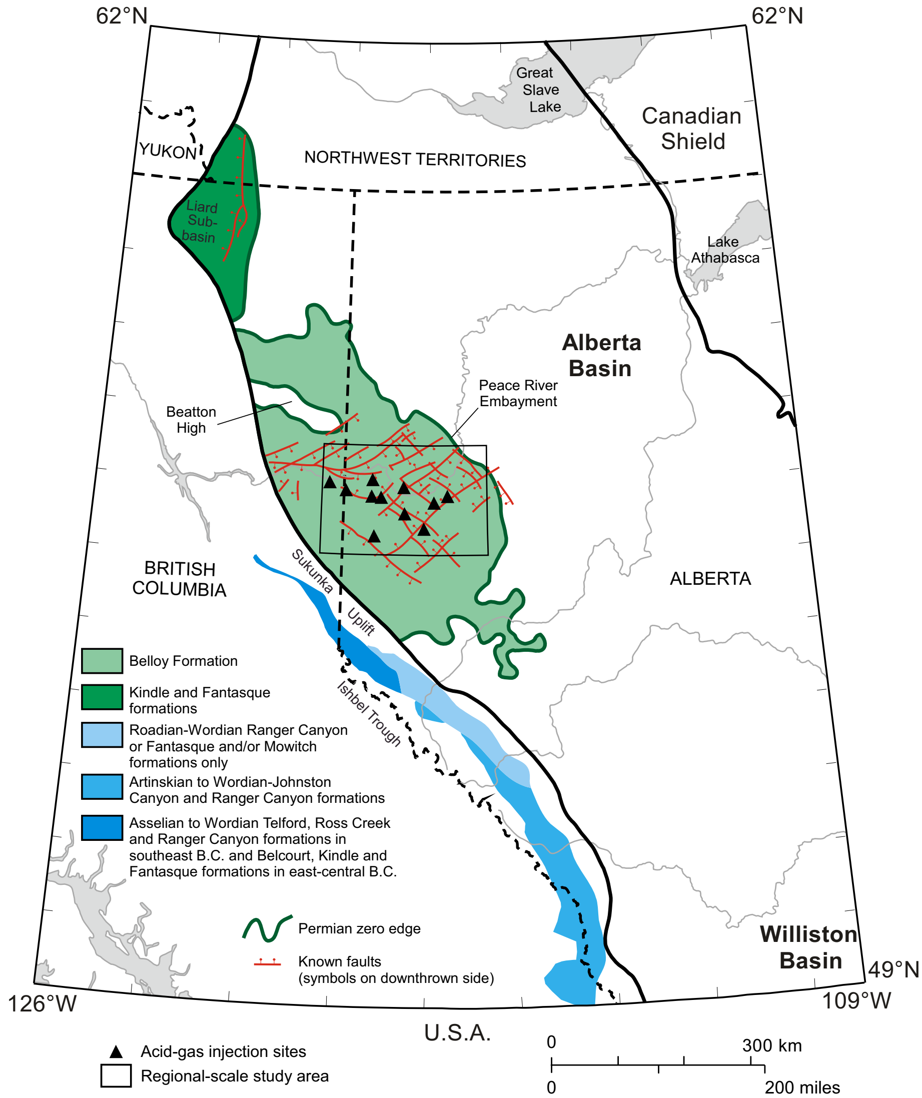


Figure 8. Tectonic elements and lithofacies distribution of Permian strata in the Alberta Basin. Note the difference between the clastic-dominated Belloy and Kindle formations in the Peace River and Liard sub-basin areas, versus carbonate dominated deposition in the Ishbel Trough. Injection takes place in the clastic-dominated Belloy Formation (modified after Henderson et al., 1994).

filled the Peace River Embayment and the Belloy Formation was draped over it. Generally, Permian strata were unconformably overlain by Lower Triassic strata; however, enhanced pre-Mesozoic erosion locally resulted in an unconformable contact between Permian and Cretaceous strata.

In the Alberta Basin, Triassic strata were deposited mainly in one large central sub-basin, the Peace River Embayment, which extended eastward from the western ocean onto the North-American craton (Figure 9). The embayment was connected to the Liard Sub-basin in the north and to deposits in the Rocky Mountains in the south. The Triassic can be subdivided into the Diaber Group and the Schooler Creek Group. Triassic sediments in the Alberta Basin were deposited as a series of three major transgressive-regressive third- or fourth- order cycles (Gibson and Barclay, 1989; Edwards *et al*., 1994). The first (lowermost) cycle involves sediments deposited along a tidally influenced, deltaic coastline with corresponding deep-marine and distal shelf deposits. The depositional environments of the second cycle show similarities to barrier island/ tidal coastlines such as those along the modern Texas Gulf coast or the Persian Gulf. The third major cycle is dominated by shallow-water carbonates.

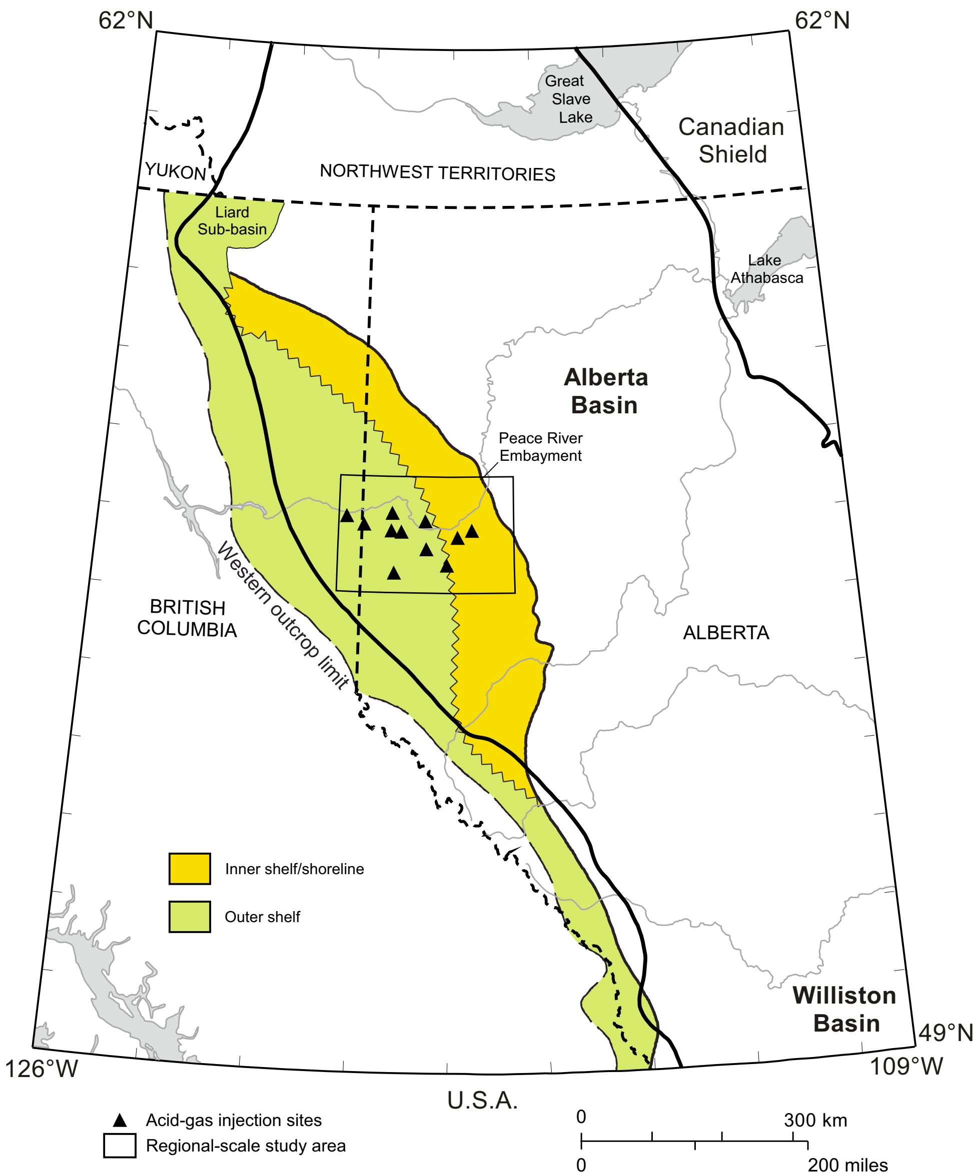


Figure 9. Depositional setting of Triassic sediments in the Alberta Basin (modified from Edwards et al., 1994).

The Lower to lower Upper Jurassic Fernie Group unconformably overlies the Triassic. Pre-orogenic, Lower Jurassic strata are characterized by thin platform limestones and phosphates and organic-rich shales with many disconformities (Smith, 1994). Upper Jurassic strata of Alberta and northeastern British Columbia record the early stages of the Columbian Orogeny (Smith, 1994). The first clear evidence of orogenic activity is found in lower Upper Jurassic strata, marked by westerly-derived fine sediments. The Fernie Group is overlain by the Late Jurassic/Early Cretaceous sandstones and minor shales of the Minnes Group and Nikanassin Formation.

Hydrostratigraphically, the shales of the Exshaw Formation and the shale-dominated lower part of the Banff Formation form the Banff-Exshaw aquitard (Figure 4). At the basin scale, the entire Upper Banff to Lower Jurassic succession forms the Jurassic-Carboniferous aquifer system. Regionally important aquitards occur within the Triassic. The Jurassic shales form the Fernie aquitard, whereas the uppermost Jurassic sandstone units are part of the overlying Cretaceous Bullhead aquifer.

Uplift, exposure, and erosion of older strata during the Late Jurassic to Early Cretaceous (Columbian orogeny) resulted in a major erosional unconformity. Along this pre-Cretaceous unconformity, southwestward-dipping strata of Jurassic to Cambrian age subcrop below the Cretaceous Mannville Group, becoming progressively older to the northeast (Figure 10).

The Cretaceous strata represent a major period of subsidence and sedimentation and are divided into several depositional successions. The Mannville Group and age-equivalent strata (Bullhead Group and Fort St. John Group) are the oldest Cretaceous rocks in the Alberta Basin. 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. The Lower Mannville Group was deposited over a broad unconformity surface cut by big valley systems. 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 (Wilrich) aquitard. In the northern part of the Alberta Basin, the entire Mannville Group consists of marine shales (Buckinghorse Formation) and forms the lower portion of the Fort S. John aquitard. 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 (Upper Fort St. John Group, Smoky 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 the Viking (Paddy-Cadotte), Dunvegan 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 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, most 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.

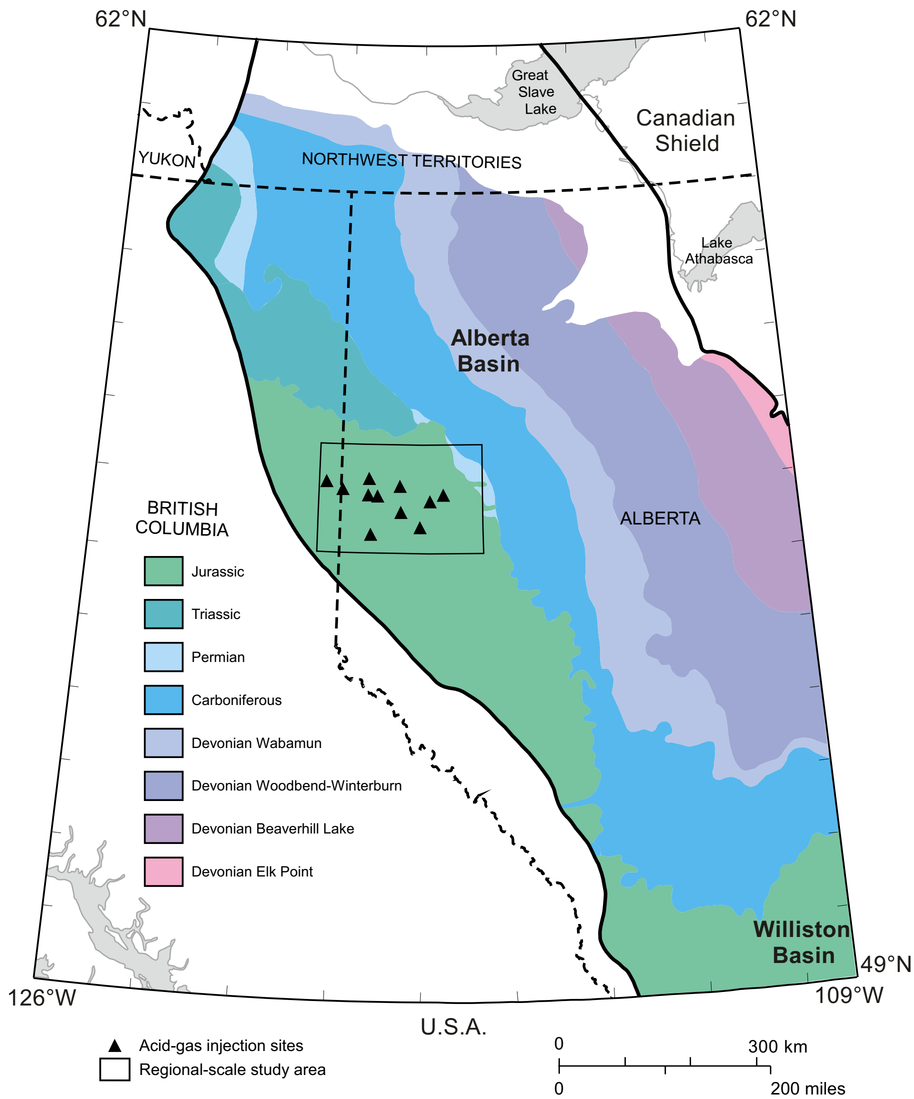


Figure 10. Structure map of the sub-Cretaceous unconformity surface. Colour coding indicates the age and lithology of strata underlying the unconformity. The strata become progressively older to the north and east (from Hayes et al., 1994).

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 11). 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 11). 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 10). 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).

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).

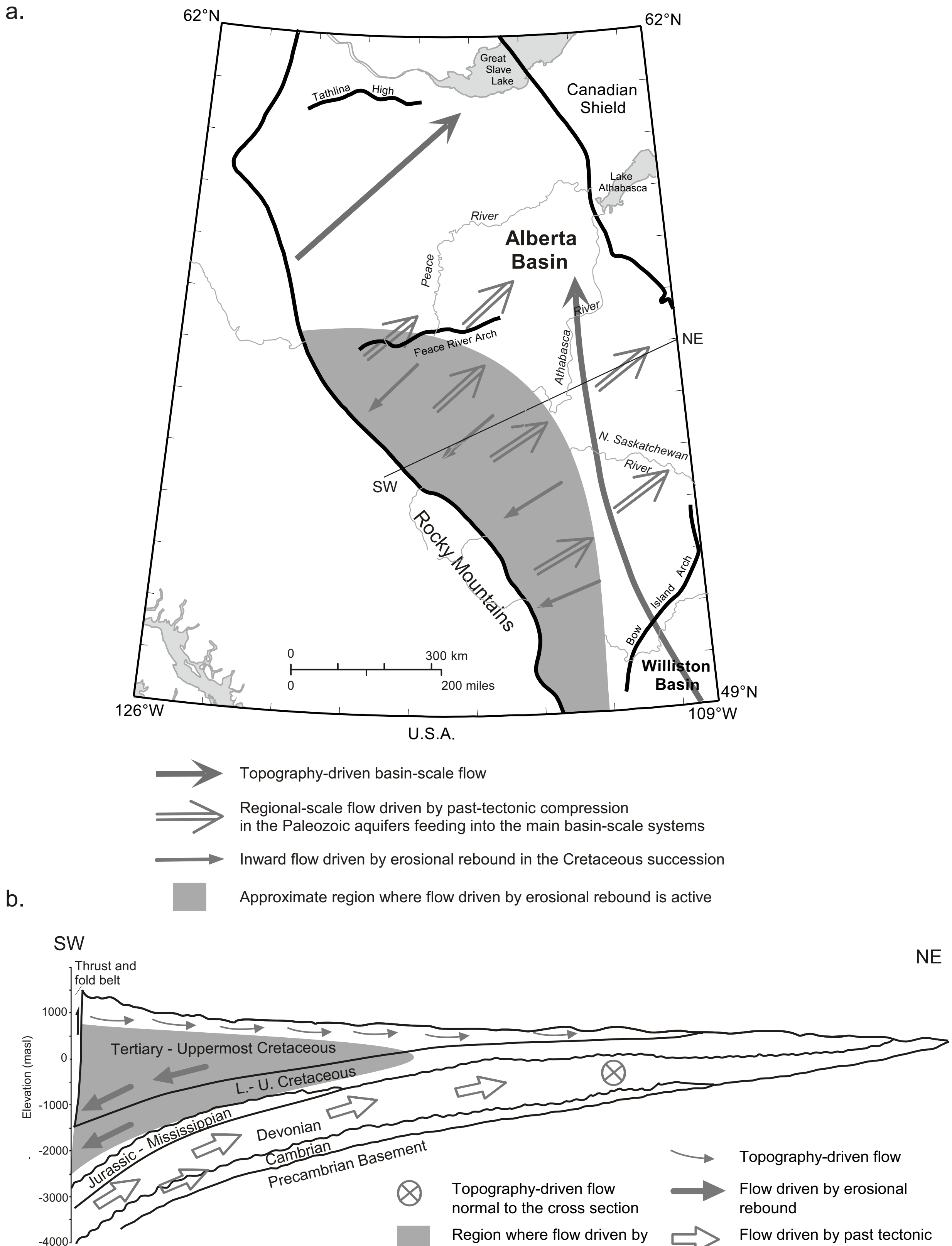


Figure 11. Diagrammatic representation of flow systems and hydrostratigraphy in the Alberta Basin: a) in plan view and b) in cross-section (after Bachu, 1999).

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 11) (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 (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 11) (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; 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, 1995a; 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 11) (Hitchon *et al*., 1990; Bachu and Underschultz, 1993, 1995; Rostron and Toth, 1997; Anfort *et al*., 2001).

4 Regional-Scale Setting of Acid-Gas Injection Sites in the Peace River Arch Area

To better understand the geology, hydrogeology, formation water flow at the acid-gas injection sites in the Peace River Arch area, and the containment of the injected acid gas, a regional-scale study area was defined between 55.1°N, 116.5°W and 56.6°N, 120.5°W (approximately Township 71 to 87 and Range 17W5 to Range 16W6) (Figure 12). The study area is located southeast of Fort St. John and straddles the Alberta-British Columbia border. Major population centers are Dawson Creek (B.C.), Grand Prairie (AB) and Peace River (AB). The ground surface elevation ranges from more than 900 m above sea level (a.s.l.) in the Rocky Mountains to the Saddle Hills in the southeast and in the Clear Hills in the north, to less than 400 m a.s.l. along the valley of the Peace River (Figure 12). The main surface water drainage is towards the Peace River, which runs eastward in the north of the study area, and towards the Smoky River in the east (Figure 13). The latter merges with the Peace River in the town of Peace River in the northeast corner of the study area.

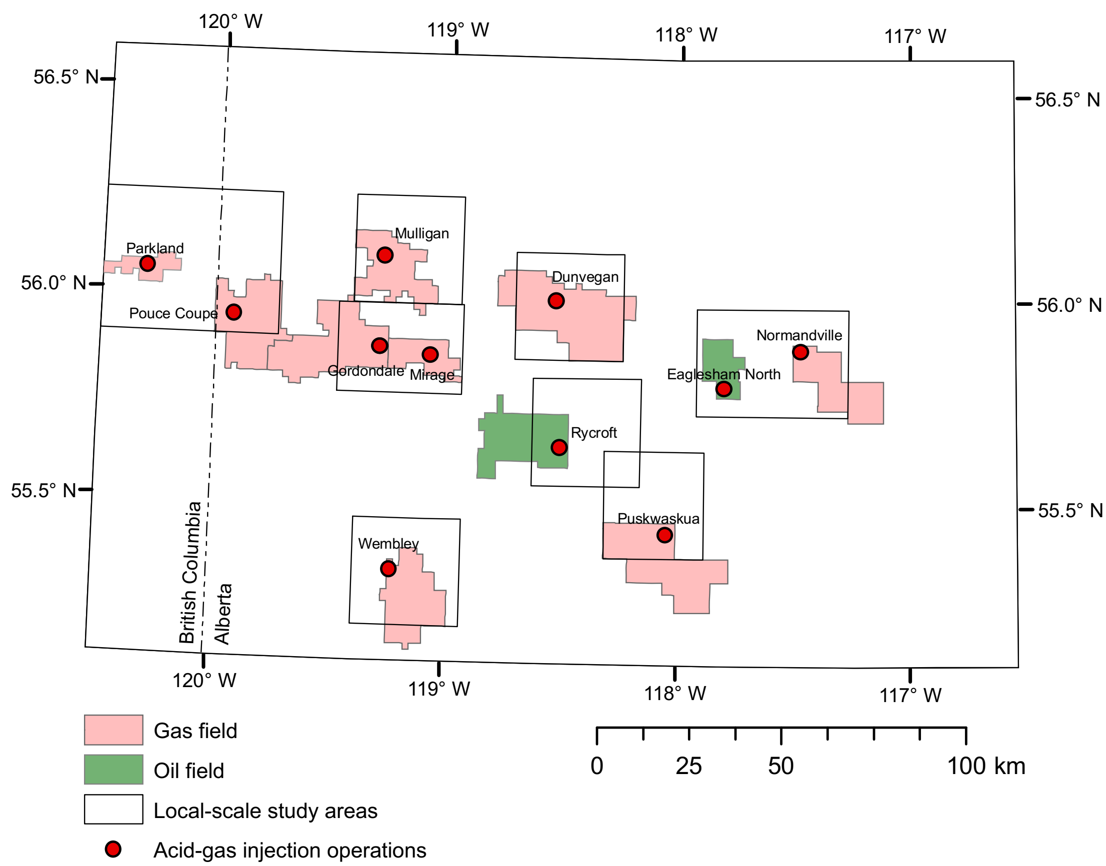


Figure 12. Location of acid-gas injection operations within the limits of the name-giving major oil and gas fields, and local-scale study areas in the Peace River Arch area.

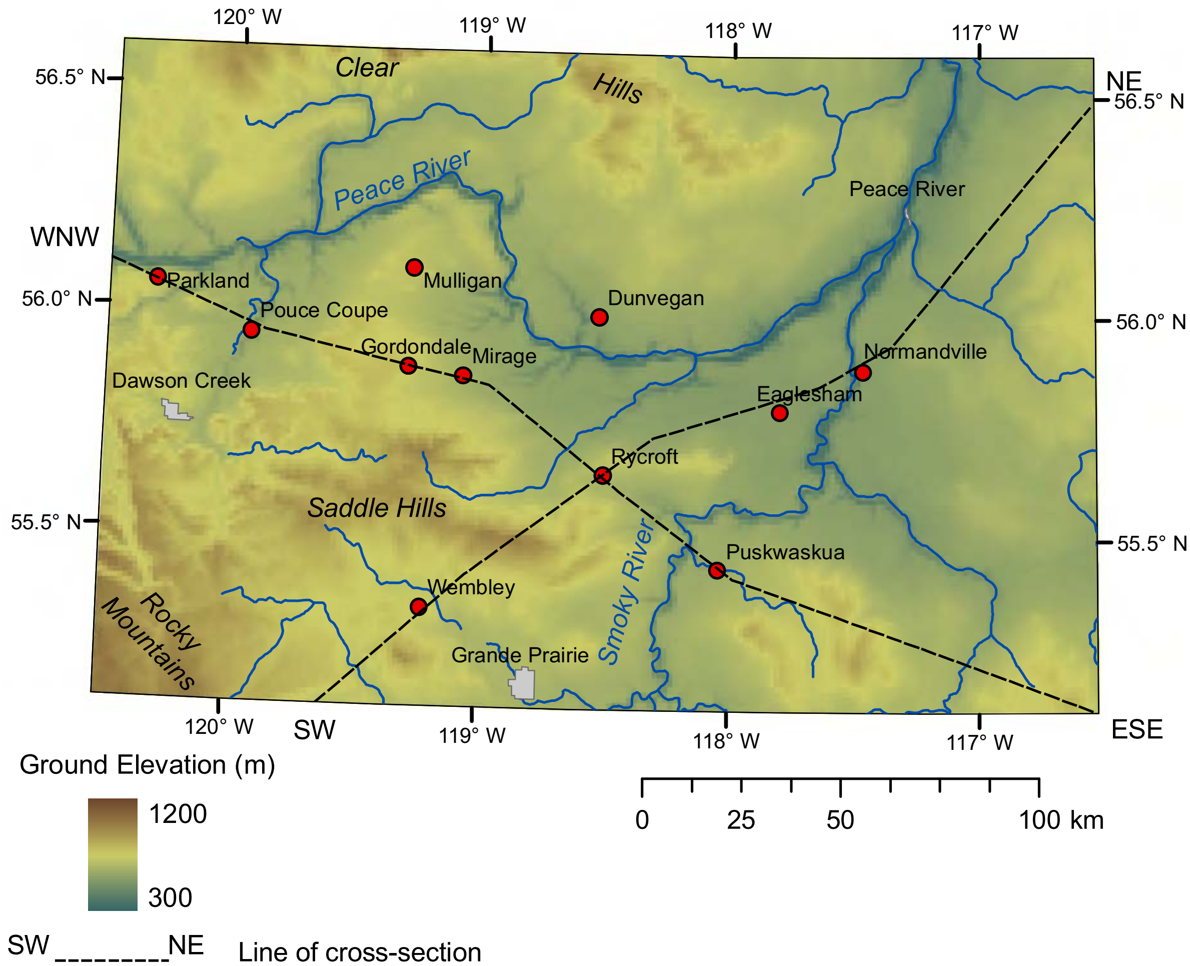


Figure 13. Topographic map of the regional-scale study area showing the location of the acid-gas injection operations in the Peace River Arch area. The lines of cross-section refer to Figure 17 and 18.

4.1 Evolution of the Peace River Arch

The Peace River Arch formed as a cratonic uplift during the Late Proterozoic. The arch was an asymmetrical structure, with major uplift along an east-west trending fault zone at its northern edge (O'Connell et al., 1990). The arch structure overprinted the pre-existing Precambrian basement structure, and several Paleo-Proterozoic fault zones may have been reactivated throughout the Phanerozoic, influencing the development of a number of structural and sedimentary features in the region. The Peace River Arch existed in three different forms during its history (O'Connell et al., 1990): a) as a late Proterozoic to early Paleozoic Arch, b) as a late Paleozoic to earliest Mesozoic Embayment (Peace River Embayment), and c) as a deep basin component of the Mesozoic foreland basin .

The Peace River Arch possibly originated as an uplift over a failed rift system in the early Paleozoic (Cant, 1988; Figure 14a). During the late Middle and Late Devonian, the emergent Arch landmass was progressively onlapped by siliciclastics, evaporites and shallow marine carbonate sediments (Figure 14b). The arch collapsed, maybe due to a later phase of rifting (Cant, 1988), and was buried by the end of the Devonian. During the early Carboniferous a series of northeast-southwest-trending interlinked grabens and half-grabens, known as the Dawson Creek Graben Complex (Barclay et al., 1990), were formed along the crest of the Devonian Arch (Figure 14c). These grabens indicate the onset of a period of local extension, possibly related to west-coast orogenies (O'Connell et al., 1990). Graben formation was mostly syndepositional, and the structures persisted through to the Permian, affecting the thickness of the sandstones in the Belloy Formation. The Fort St. John Graben is the main graben in the complex, which has a generally easterly trend and is intensely segmented and block-faulted (Figure 15). The Dunvegan Horst separates the Fort St. John Graben from the Hines Creek and Belloy grabens to the east. The latter is separated from the Grimshaw Graben by the Tangent Horst. The faults that delineate the main structural features of the Dawson Creek Graben Complex are from west to east: Bear Canyon, Gordondale, Saddle Hills, Hines Creek, Whitemud, Dunvegan, Tangent, and Peace River (Figure 15). Many structural elements in the Peace River Arch area have alternative names (see review by Mei, 2006), and the nomenclature in this report is based on names commonly used in the petroleum industry.

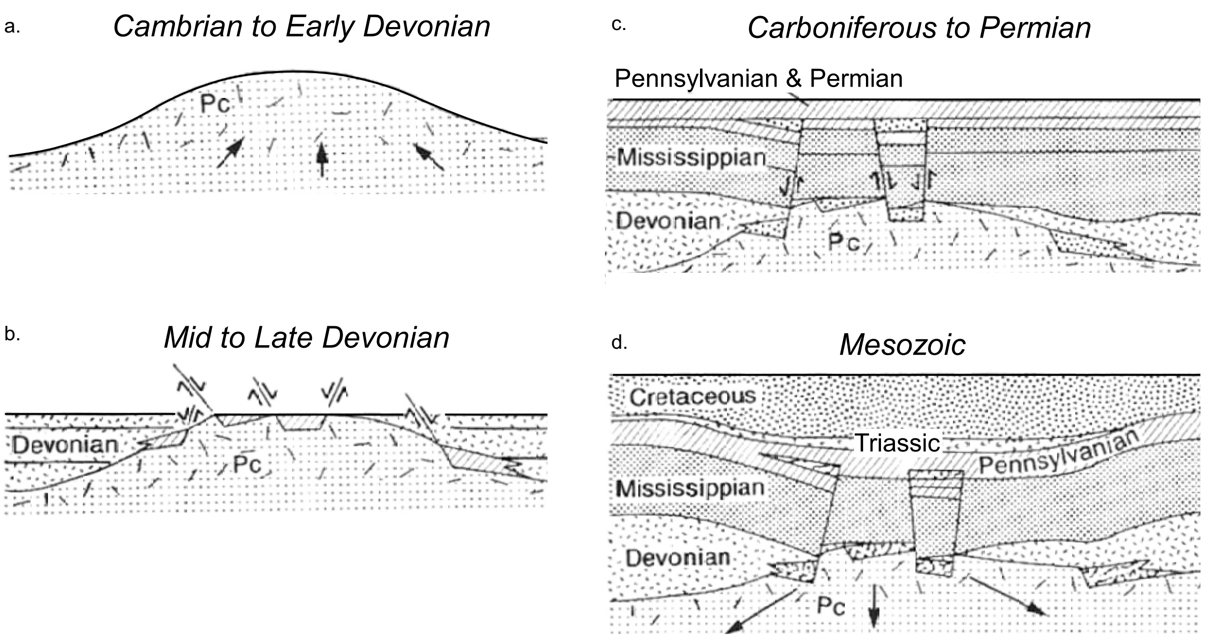


Figure 14. Diagrammatic summary of the history of the Peace River Arch (modified from Cant, 1988).

A wide, gently subsiding embayment was present in the region during the Triassic, leading to the deposition of siliciclastics (Figure 14d). During the development of the Jurassic and Cretaceous foreland basin, localized subsidence occurred in the Peace River Arch region, and the underlying structure, particularly the Early Carboniferous graben system, appears to have influenced Cretaceous basin configuration and facies distribution (Leckie et al., 1990).

4.2 Geology of the Upper Devonian to Triassic

Acid gas injection occurs in the Upper Devonian Woodbend and Wabamun groups, the Carboniferous Stoddart Group, and the Permo-Triassic succession (Figure 16), which will be the focus of this chapter. A major erosional event during Jurassic times resulted in the pre-Cretaceous unconformity along which Triassic to Carboniferous formations subcrop below the Cretaceous Bullhead Group. The stratigraphic and structural relationships between various injection units are shown along two cross-sections in Figures 17 and 18.

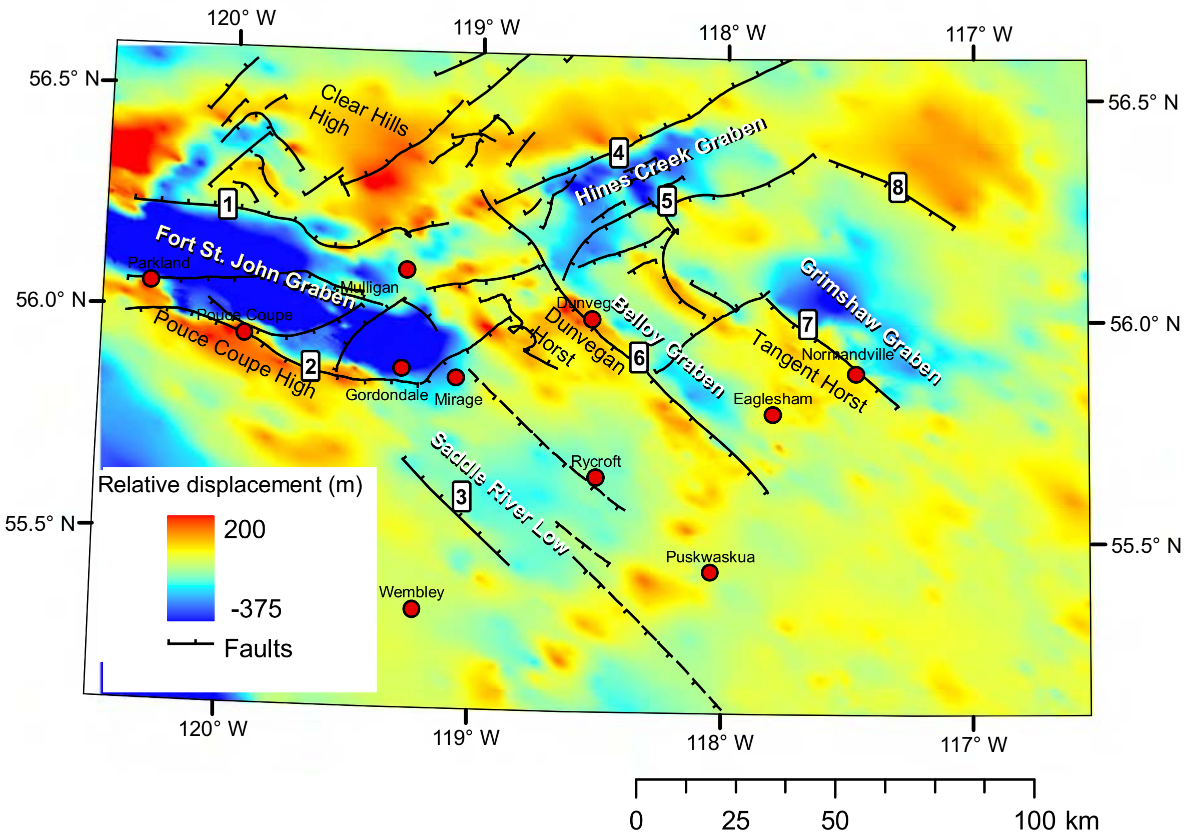


Figure 15. Structural features of the Dawson Creek Graben Complex superimposed on the residual map for the top of the Debolt Formation (after Mei, 2006). The major faults are (modified from Richards et al., 1994): 1) Bear Canyon, 2) Gordondale, 3) Saddle Hills, 4) Hines Creek, 5) Whitemud, 6) Dunvegan, 7) Tangent, and 8) Peace River.

4.2.1 Devonian Woodbend Group

The Upper Devonian Woodbend Group in the Peace River Arch area consists of shallow-water carbonates of the Leduc Formation, as well as deeper-water carbonates and shales of the Ireton Formation (Figures 16 and 19). The Leduc Formation represents three stages of carbonate platform development, surrounding and onlapping the insular continental landmass of the emergent Peace River Arch (Dix, 1990). The platform edge is formed generally by clean dolostone, whereas landwards siliciclastics become more dominant (Figure 19).The Woodbend Group overlies the siliciclastics and carbonates of the Beaverhill Lake Group and interfingers with the Granite Wash Formation, the latter forming a discordant sandstone layer directly overlying the Precambrian basement (Dix, 1990) (Figure 18).

The depth to the top of the Leduc Formation in the study area ranges from 5000 m in the southwest to less than 2000 m in the northeast (Figure 20 a). Along the southern rim of the Peace River Arch, the top of the Leduc Formation dips southwestward from above -1200 m to -3200 m a.s.l. with a slope of about 12 m/km (Figure 20b). North of the Arch, the Leduc formation dips southwestward from above -1200 m to -2100 m a.s.l. with a slope of about 4 m/km. Local structural highs in the north and east portions of the study area coincide with the outline of Carboniferous structural lineaments.

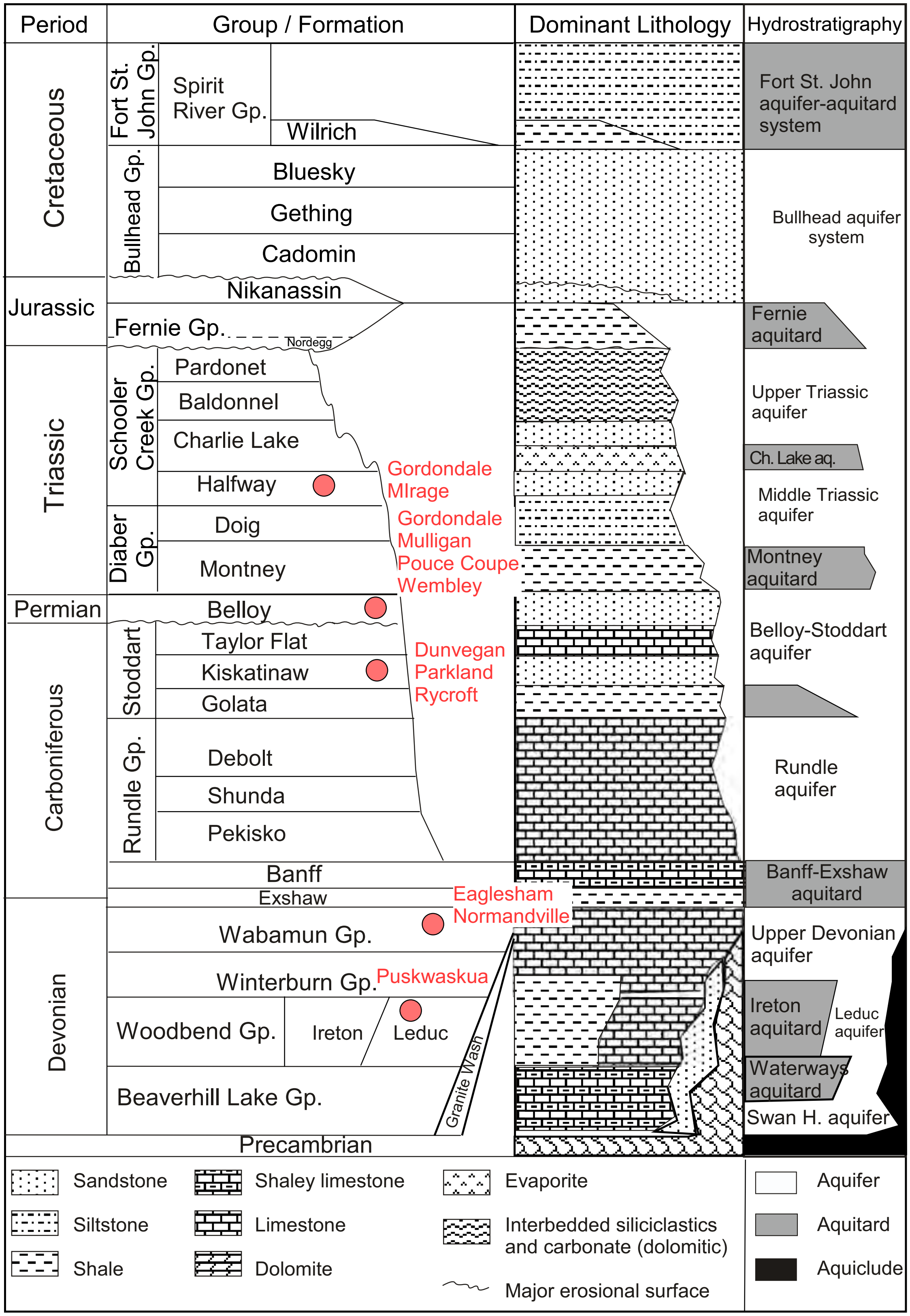


Figure 16. Stratigraphy, general lithology and hydrostratigraphy of the Mississippian to Lower Cretaceous (Spirit River Group) succession in the study area. Acid-gas injection horizons are indicated by red circles.

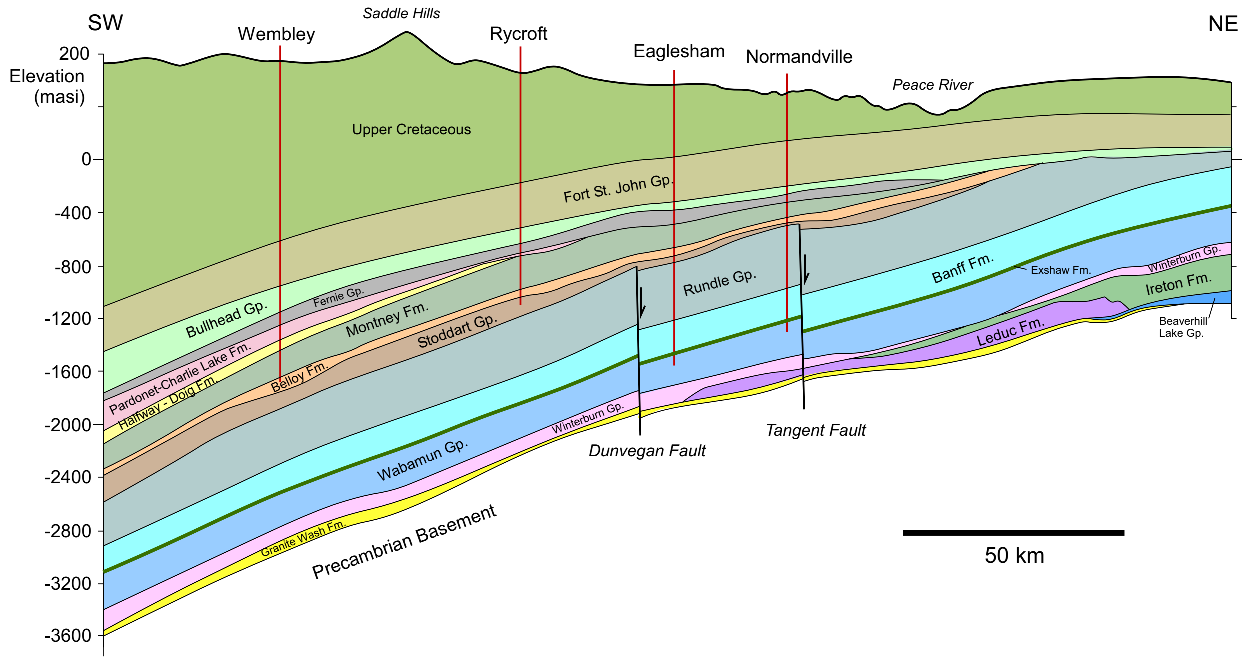


Figure 17. Stratigraphic SW-NE cross-section through the regional-scale study area showing the relative position of some of the target horizons in the Devonian to Triassic succession for acid-gas injection in the Peace River Arch area. The location of the cross-section is shown in Figure 13.

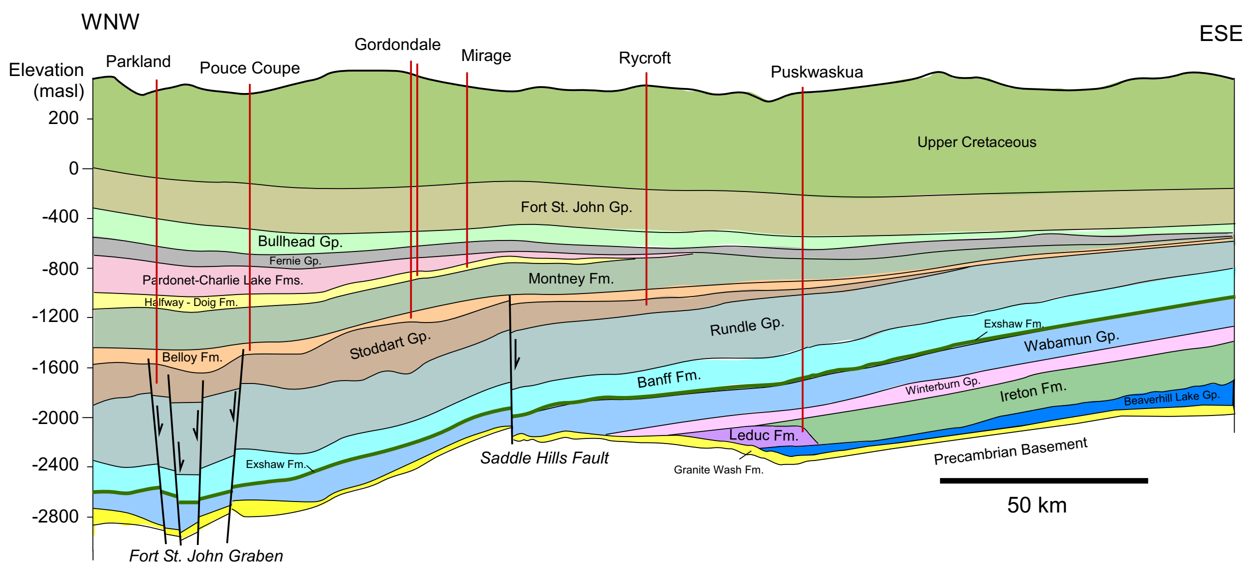


Figure 18. Stratigraphic WNW-ESE cross-section through the regional-scale study area showing the relative position of some of the target horizons in the Devonian to Triassic succession for acid-gas injectiton in the Peace River Arch area. The location of the cross-section is shown in Figure 13.

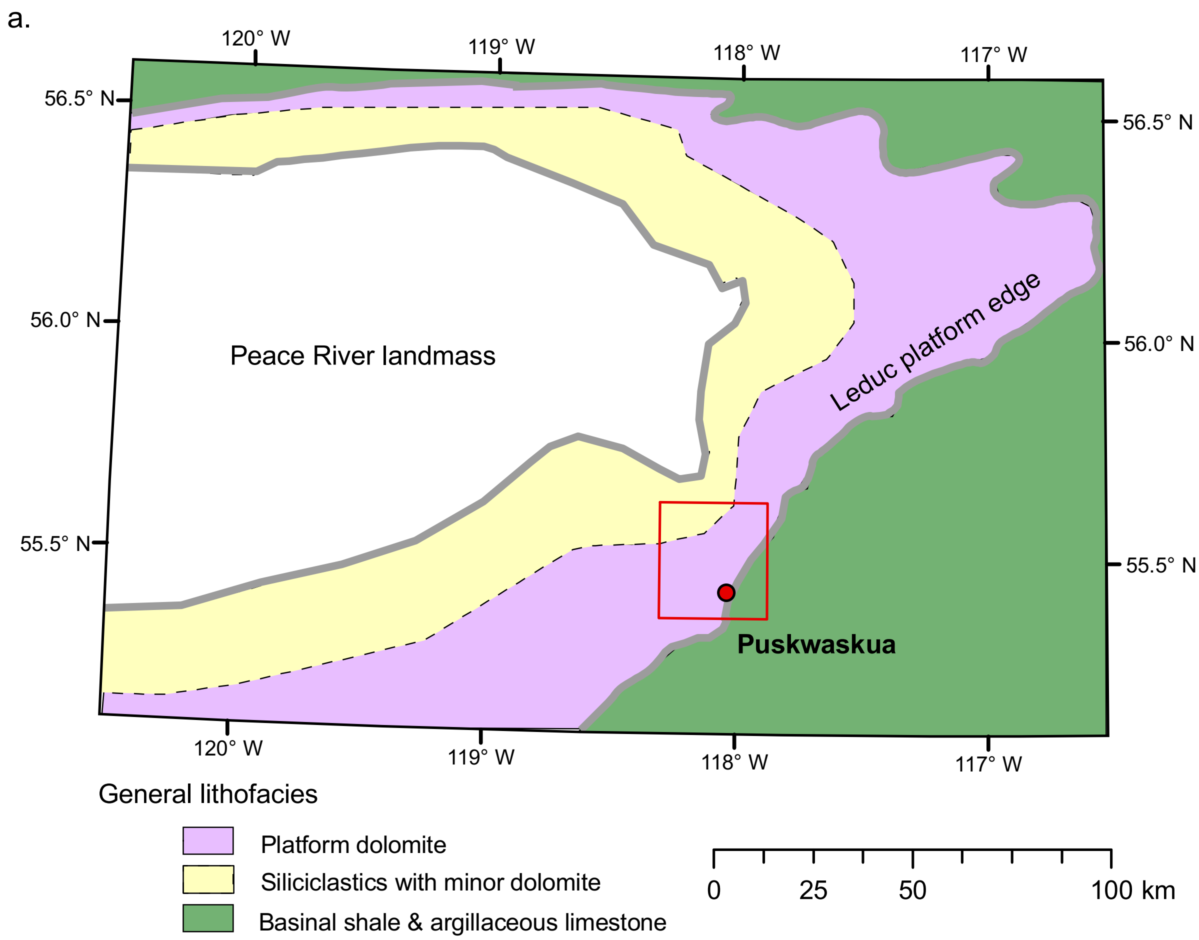


Figure 19. General lithofacies distribution in the Woodbend Group in the regional-scale study area (generalized and modified after Dix, 1990). The location of the Puskwaskua injection site and the outline of its local-scale study area (red box) are also shown.

The thickness of the Leduc Formation increases basinward from less than 50 m to approximately 250 m. The Woodbend Group is conformably overlain by basinal argillaceous carbonates as well as platform carbonates of the Winterburn Group (Dix, 1990).

4.2.2 Devonian Wabamun Group

The Wabamun Group in the regional study area consists mainly of an equivalent to the Stettler Formation, generally uniform, micrite-dominated carbonate ramp deposits which thin across the top of the Peace River Arch, indicating that the Arch was almost completely submerged during the later stages of the Upper Devonian (Halbertsma and Meijer Drees, 1987). The uppermost portion of the Wabamun Group, the sediments equivalent to the Big Valley Formation, was eroded at the end of the Devonian over most of the Peace River Arch (Halbertsma, 1994). The Wabamun Group carbonates were locally dolomitized (Figure 21). The dolomitized pods in the upper part of the Wabamun Group are the targets for acid-gas injection.

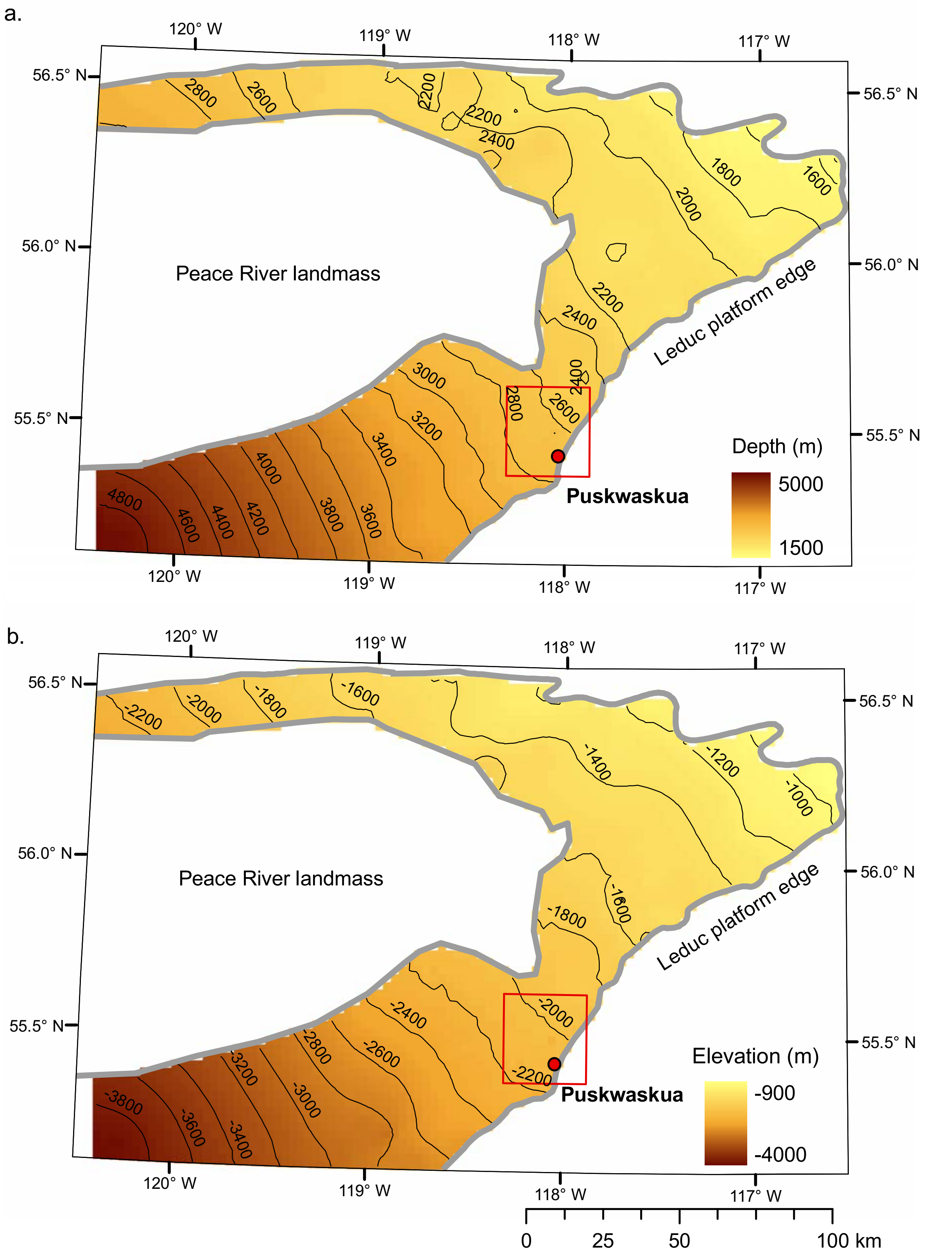


Figure 20. Main gelogocial features of the Leduc carbonate platform in the regional-scale study area: a) depth to top and b) structure elevation. The location of the Puskwaskua injection site and the outline of its local-scale study area (red box) are also shown.

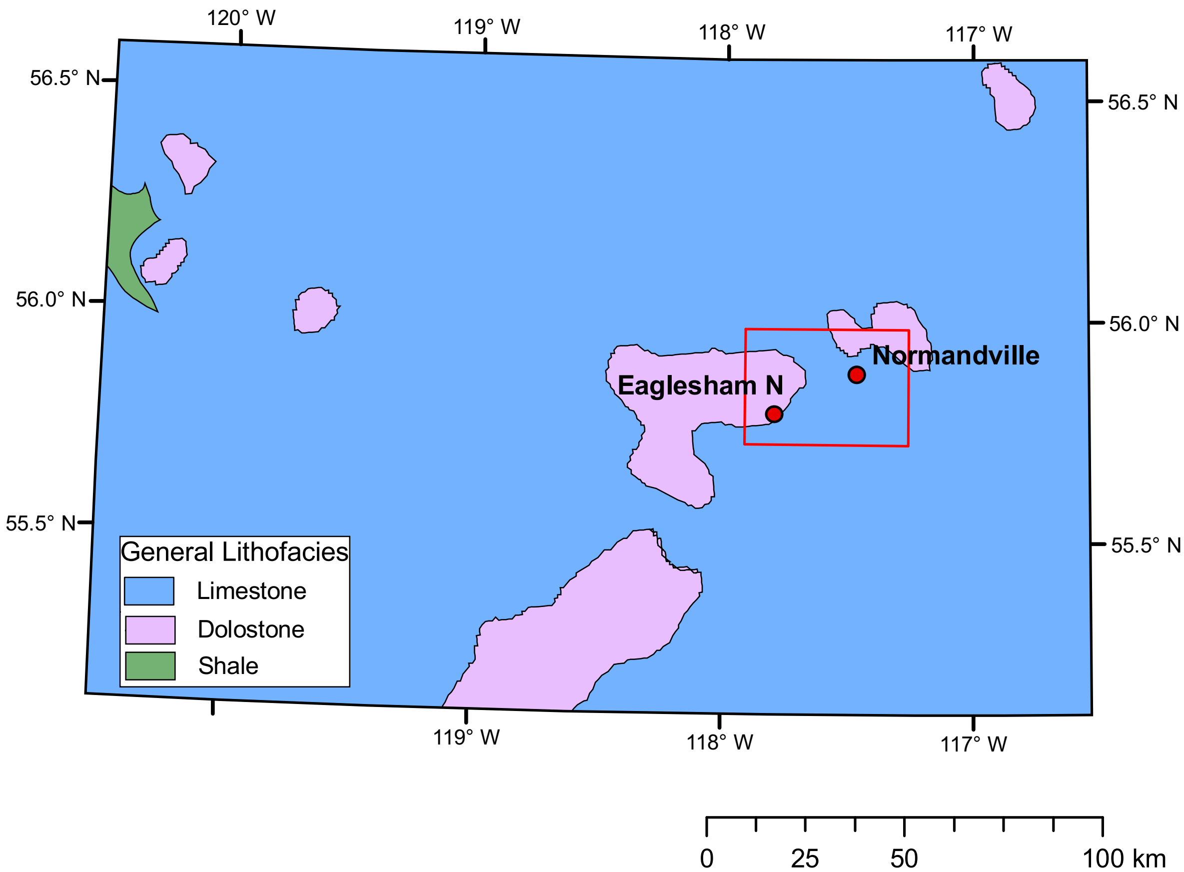


Figure 21. General lithofacies distribution in the Wabamun Group in the regional-scale area (after Halbertsma, 1994). The location of the Normandville and Eaglesham injection sites and the outline of the local-scale study area (red box) are also shown.

Two dominant fault trends are present in the Wabamun Group in the Peace River Arch area. Northwest-trending synthetic extension faults provided the pathway for dolomitizing fluids into the Wabamun limestones (Packard et al., 1992). Northeast-southwest transverse faults were developed during crustal extension and development of the Peace River Embayment during the Carboniferous after Wabamun Group deposition.

The depth to the top of the Wabamun Group in the regional-study area ranges between more than 4500 m in the southwest to less than 1000 m in the northeast (Figure 22a), with a decreasing thickness from 200 m to 0 m in small areas above the crest of the Peace River Arch. The top of the Wabamun Group dips southwestward with a slope of 4.6 m/km, from above -400 m in the northeast to less than -3200 m a.s.l. in the southwest (Figure 22b). The locations of southwest-northeast trending troughs in the northwest part of the structure map coincide with the Fort St. John Graben system, indicating that Wabamun Group strata were affected by faulting in the Carboniferous.

The Wabamun Group is underlain by off-lapping carbonate platforms (the Nisku and Blueridge formations) which transition away from the crest of the Peace River Arch into basinal sediments (Moore, 1989). The Wabamun Group is overlain by several metres of tight shale of the Exshaw Formation followed by up to 120 m of shaly carbonates of the Mississippian Banff Formation.

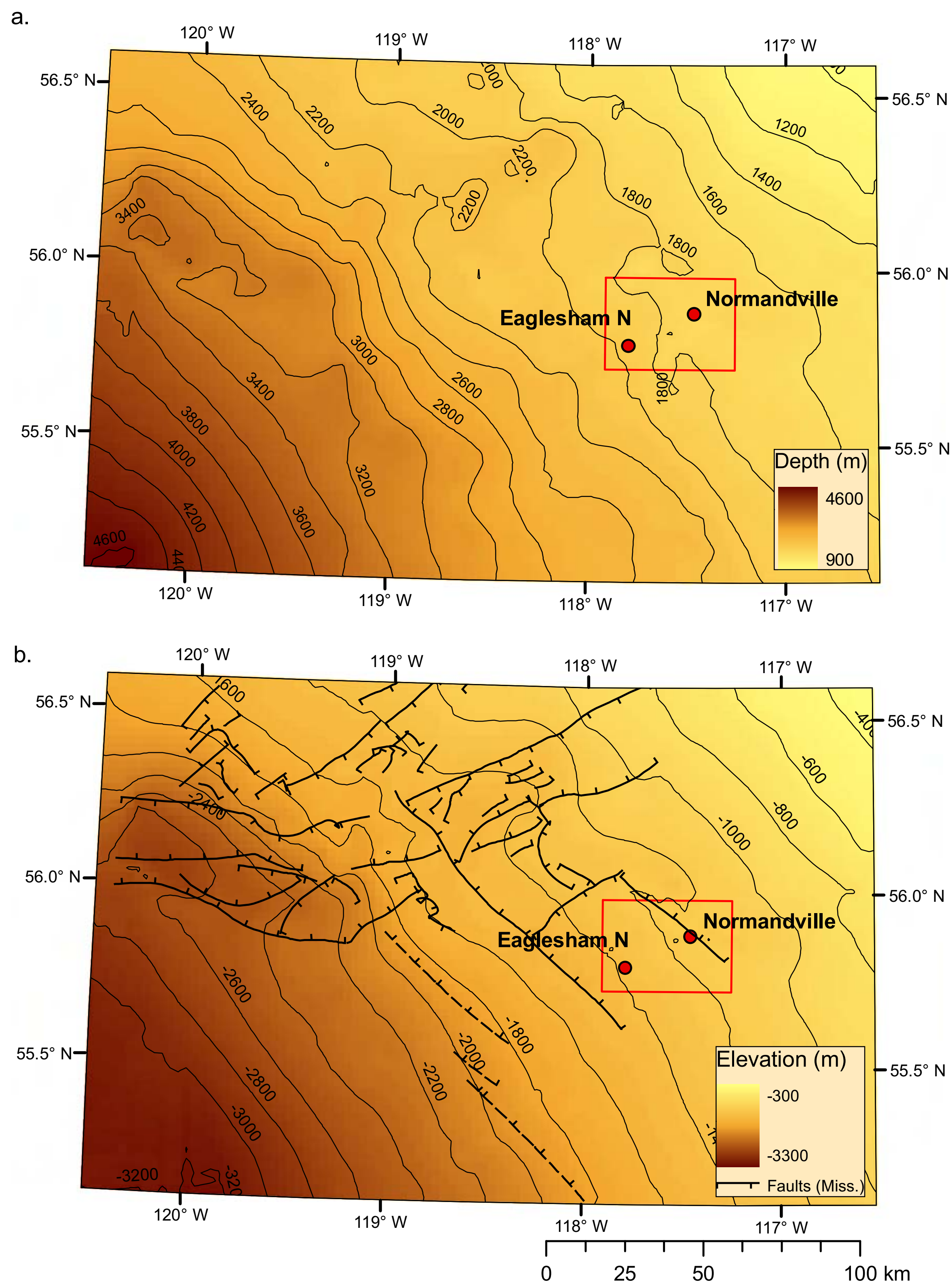


Figure 22. Main geological features of the Wabamun Group in the regional-scale study area: a) depth to top and b) structure elevation and Mississippian faults. The location of the Normandville and Eaglesham injection sites and the outline of the local-study area (red box) are also shown.

4.2.3 Carboniferous

In the study area, a thick Carboniferous succession was deposited in the Peace River Embayment, which was a major zone of subsidence in northwestern Alberta and northeastern British Columbia during Carboniferous to Triassic time. Due to a series of erosional and non-depositional events from the Carboniferous to Early Cretaceous, Carboniferous formations successively subcrop from southwest to northeast underneath Permian, Triassic or Cretaceous strata (Figure 17). The total thickness of the Carboniferous strata increases from 400 m in the northeast to 1000 m in the southwest. The major stratigraphic subdivisions in the Carboniferous are the Banff Formation, the Rundle Group and the Stoddart Group. The Rundle and Stoddart groups can be further subdivided into the Pekisko, Shunda and Debolt formations, and the Golata, Kiskatinaw and Taylor Flat formations, respectively (Figure 16).

The Banff Formation and the Rundle Group form overall shallowing-upward successions. Calcareous shales of the Lower Banff and Pekisko formations were deposited in a basin to slope setting, passing upward into shallow and restricted shelf carbonates in the upper Banff, as well as in the Shunda and Debolt formations (O'Connell, 1990).

Major graben structures were initiated during the deposition of the Debolt Formation, which controlled the sedimentation of the Stoddart Group and Belloy Formation in the Dawson Creek Graben Complex (Barclay et al., 1990).

The Rundle Group is overlain by the Stoddart Group, which consists of mixed siliciclastics and carbonates (Figure 23). The base of the Stoddart Group is formed by the Golata Formation, which marks a distinct change from carbonate to siliciclastic depositional settings. The Golata Formation consists of siltstones and shales that were deposited in tidal or estuarine, delta-like complexes (Barclay *et al*., 1990). The overlying sandstone-dominated Kiskatinaw Formation was deposited in a coastal plain environment sourced from the east and changes westward into more open marine limestones and shales (Barclay *et al*., 1990). The sandstones in the Kiskatinaw Formation are the targets for acid-gas injection. The Taylor Flat Formation, the uppermost formation in the Stoddart Group, was deposited in an open marine, outer shelf environment and consists of sandy carbonates that grade into calcareous sandstones and shale (Barclay *et al*., 1990, Richards *et al*., 1994).

The top of the Stoddart Group dips southwestward from approximately -100 m to -2800 m a.s.l. (Figure 24a) and its depth ranges from 1000 to 3700 m below the ground surface (Figure 24b). The thickness of the Stoddart Group in the regional-scale study area ranges from 0 m at its erosional edge in the north and southeast to 400 m in the northwest, in the center of the Fort St. John Graben.

Most of the boundaries between the various Carboniferous formations are conformable, at least in the centre of the Peace River Embayment. Towards the basin margins however, formation contacts, especially in the Upper Carboniferous succession, become increasingly unconformable due to non-deposition and erosion in more terrestrial environments. Ultimately, the entire Stoddart Group is absent in the northern and southeastern parts of the study area, were the Lower Carboniferous Debolt Formation is overlain by the Permian Belloy Formation.

4.2.4 Permian (Belloy Formation)

Sediments of the Permian Belloy Formation were deposited in a shallow-marine shelf setting (Naqvi, 1972) and consist of interbedded siliciclastics and carbonates. Dolomitic sandstones were deposited preferentially along the margins of the Peace River Embayment, in tidally influenced shoreline

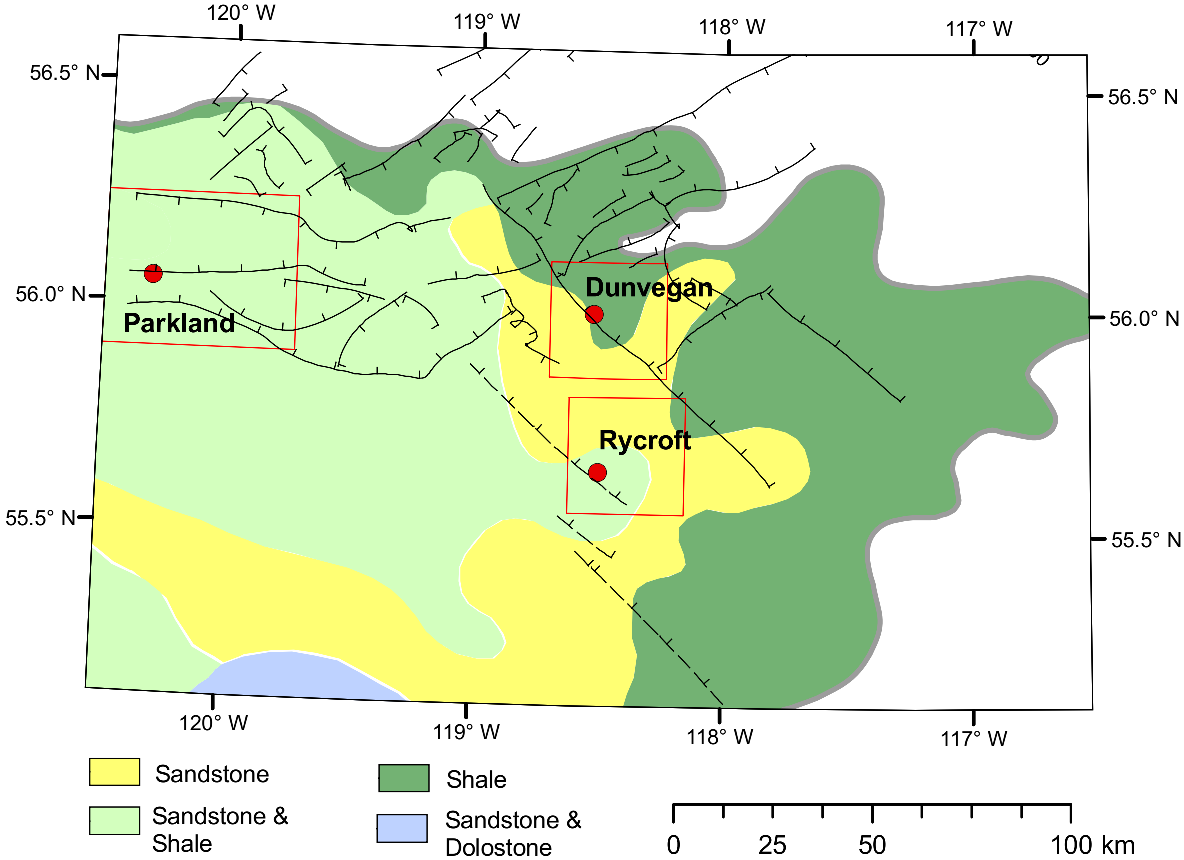


Figure 23. General lithofacies distribution in the Stoddard Group in the regional-scale study area (after Richards et al. 1994). The location of the Dunvegan, Parkland, and Rycroft injection sites and the outlines of their respective local-scale study areas (red box) are also shown.

environments. In the Peace River Arch area, the Belloy Formation sandstones pass westwards and towards the basin centre into less porous dolostones and deeper marine carbonates, siltstones, and chert (Henderson *et al*., 1994) (Figure 25). The Belloy Formation can be subdivided into three units: a) a lower carbonate member, consisting of fine-grained, glauconitic quartz arenites, siltstone and cherty, dolomitic limestone, b) a middle sandstone member, consisting of medium-grained, glauconitic, and phosphatic quartz arenites, and c) an upper carbonate member, consisting of dolomitic limestone, dolostone, glauconitic sandstones, and bedded chert (Halbertsma, 1959; Henderson *et al*., 1994). Both the top and the bottom of the Permian form unconformable boundaries with overlying Triassic to Lower Cretaceous strata and underlying Carboniferous strata, respectively.

The thickness of the Permian increases southwestward from 0 m at its erosional edge to approximately 150 m). The top of the Permian dips southwestward from -100 m to -2800 m a.s.l. (Figure 26a) and the depth ranges from 500 m to 3700 m below the ground surface (Figure 26b).

4.2.5 Triassic

The Triassic strata were deposited within the tectonically active, subsiding Peace River Embayment (Figure 8) as a series of three major transgressive-regressive (T-R) third- or fourth- order cycles (Gibson

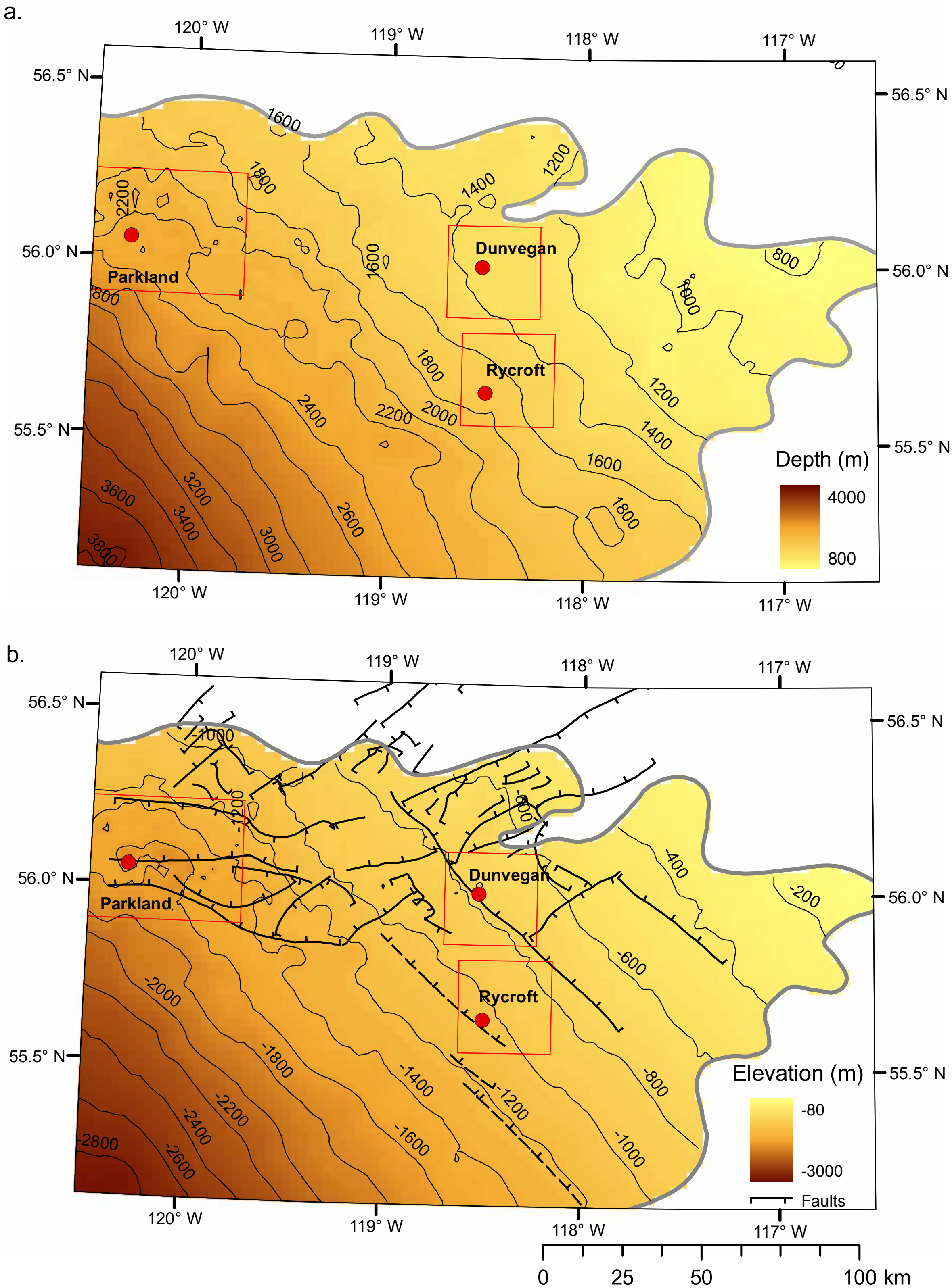


Figure 24. Main geological features of the Stoddart Group in the regional-scale study area: a) depth to top and b) structure elevation and Mississippian faults. The location of the Dunvegan, Parkland, and Rycroft injection sites and the outline of their respective local-scale study areas (red box) are also shown.

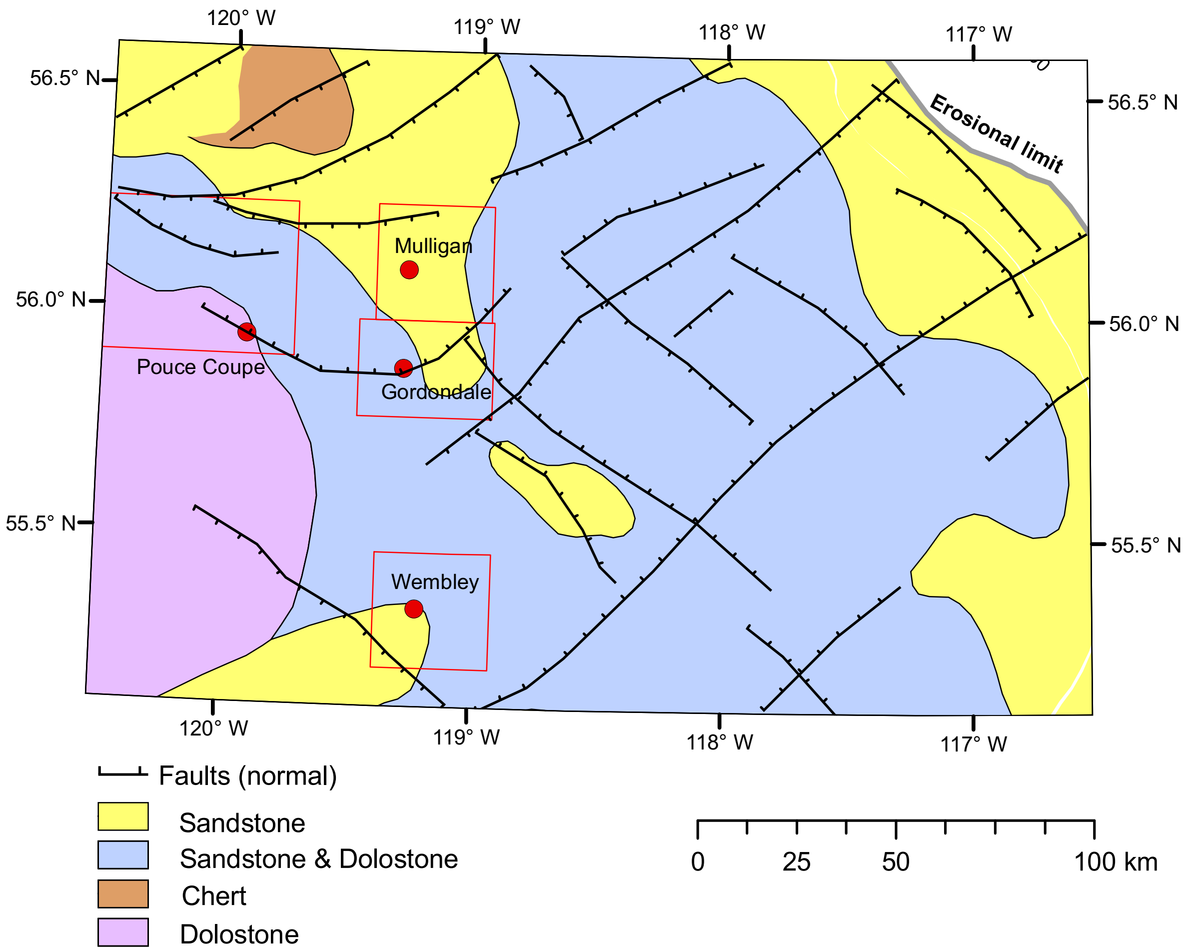


Figure 25. General lithofacies distribution in the Belloy Formation in the regional-scale study area (after Henderson et al., 1994). The location of the Gordondale, Pouce Coupe, Mulligan, and Wembley injection sites and the outline of their respective local-scale study areas (red box) are also shown.

et al., 1989; Edwards *et al*., 1994). The first (lowermost) T-R cycle is represented by the Montney Formation (Lower Daiber Group) and comprises sediments deposited along a tidally influenced, deltaic coastline with corresponding deep-marine and distal shelf deposits. Along its eastern subcrop edge, the Montney Formation consists of thin shoreface sandstones mixed with finer siliciclastics thickening southwestwards to more than 250 m and passing into calcareous and dolomitic siltstones and shales (Figure 27a).

Strata of the overlying Doig Formation (upper Daiber Group), Halfway and Charlie Lake formations (Lower Schooler Creek Group) represent the second T-R-cycle. Due to similar lithology, it is often difficult to assign a distinct contact between the Doig and Halfway formations and a combined lithofacies distribution is shown in Figure 27b. The combined thickness increases from 0 m along the subcrop edge to 150 m along the deformed belt in the southwest. The Doig Formation consists of a succession of fine sandstones, siltstones and shales that were deposited in a marine shelf environment. Sandstones of the Halfway Formation were deposited in a beach/barrier island setting (Gibson and Edwards, 1990) and are generally coarser than the sandstones in the overlying Doig Formation. Discontinuous accumulations of quartzose sandstone and dolomitic coquina along the subcrop edge of the Halfway Formation grade

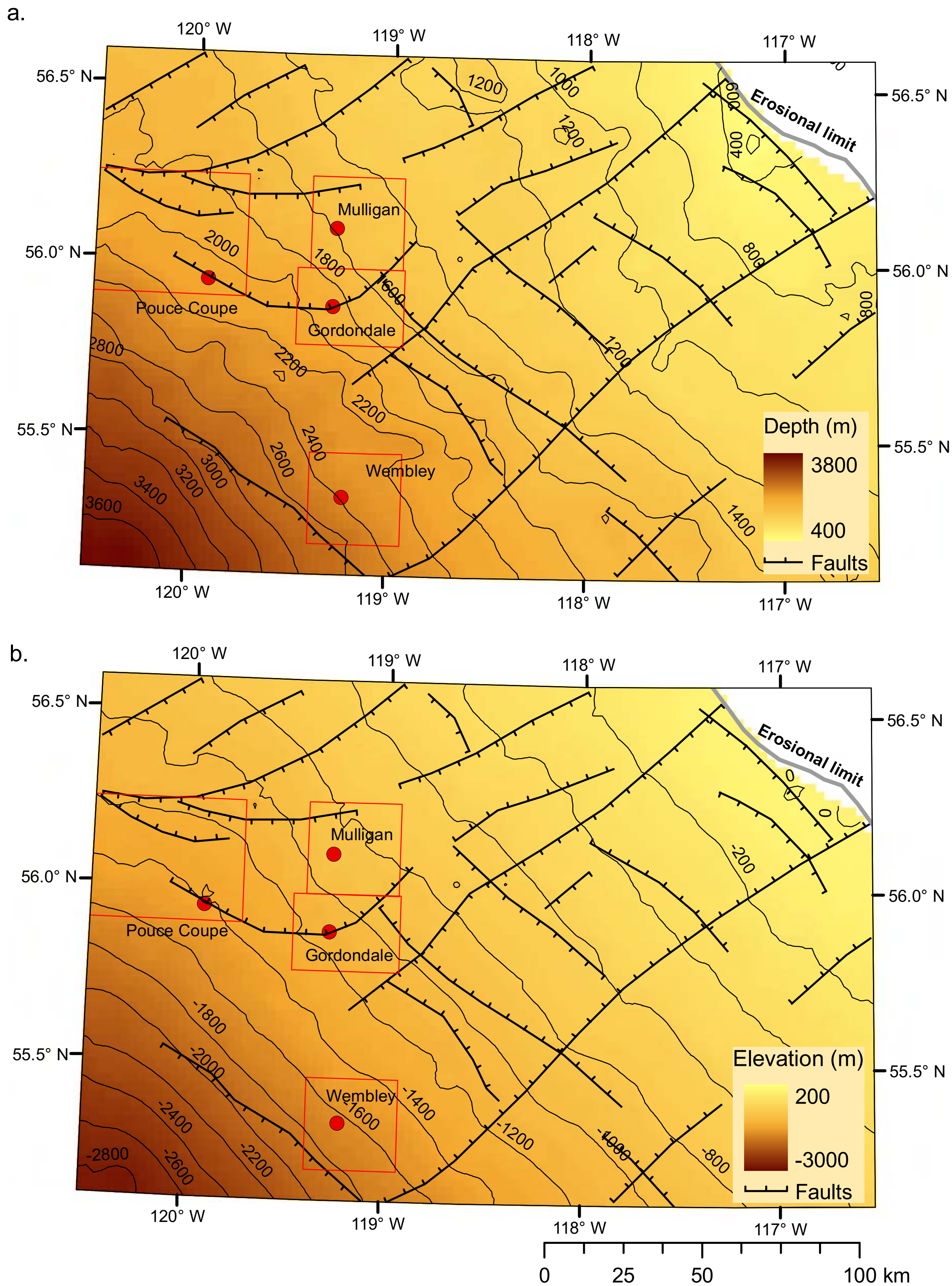


Figure 26. Main geological features of the Belloy Formation in the regional-scale study area: a) depth to top and b) structure elevation. The location of the Gordondale, Pouce Coupe, Mulligan, and Wembley injection sites and the outline of their respective local-scale study areas (red box) are also shown. Interpretation of faults from Henderson et al. (1994).

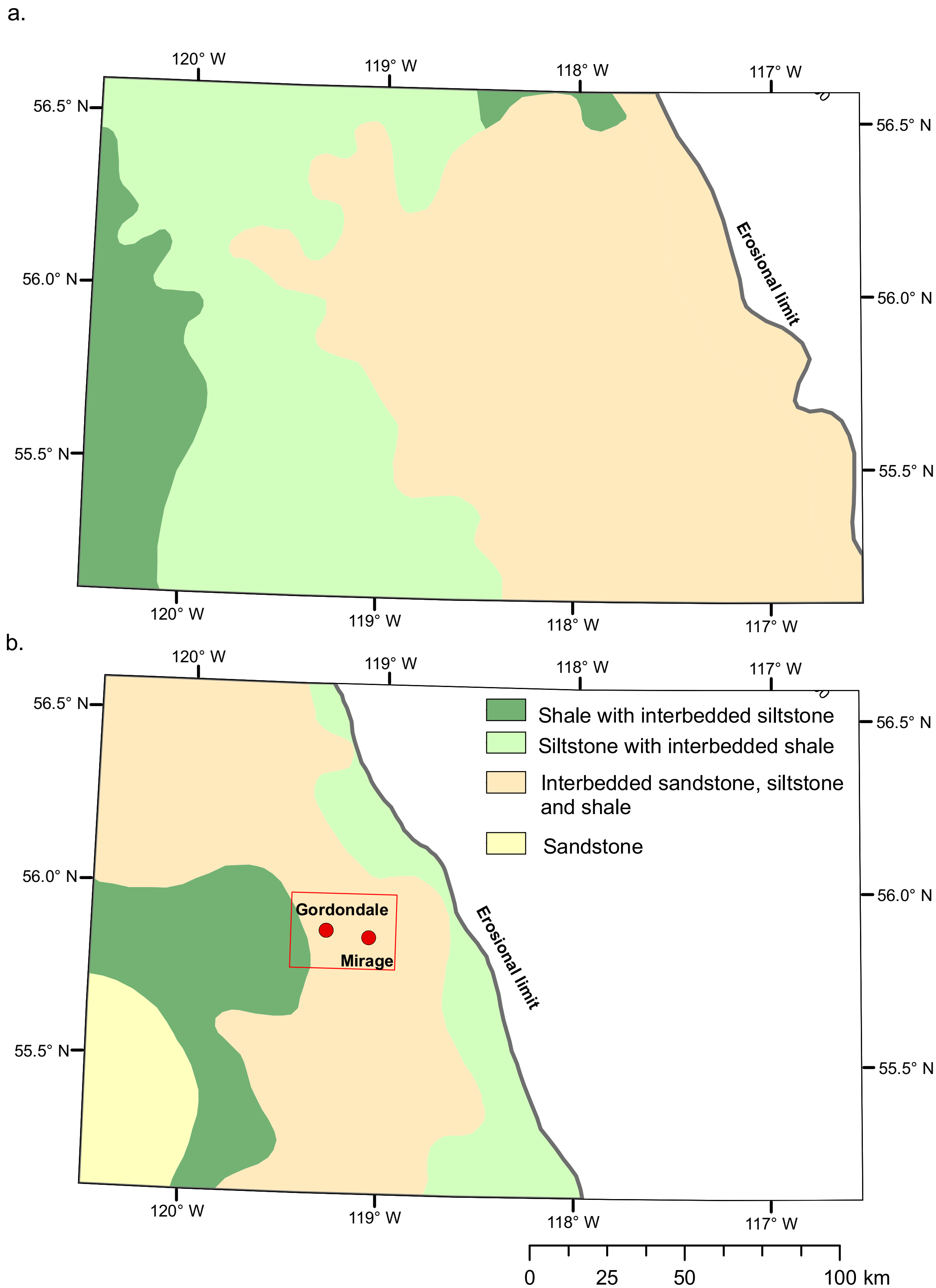


Figure 27. General lithofacies distribution in the a) Montney and b) Halfway-Doig formations in the regional-scale study area (after Edwards et al., 1994). The location of the Gordondale and Mirage injection sites and the outline of their local-scale study area (red box) are also shown.

westward into thick, continuous shoreface sandstones (Edwards *et al*., 1994). Acid gas is injected into the Halfway Formation, which.dips southwestward from -500 m to -2400 m a.s.l. (Figure 28a) and the depth ranges from 1100 m to 3300 m below the ground surface (Figure 28b).

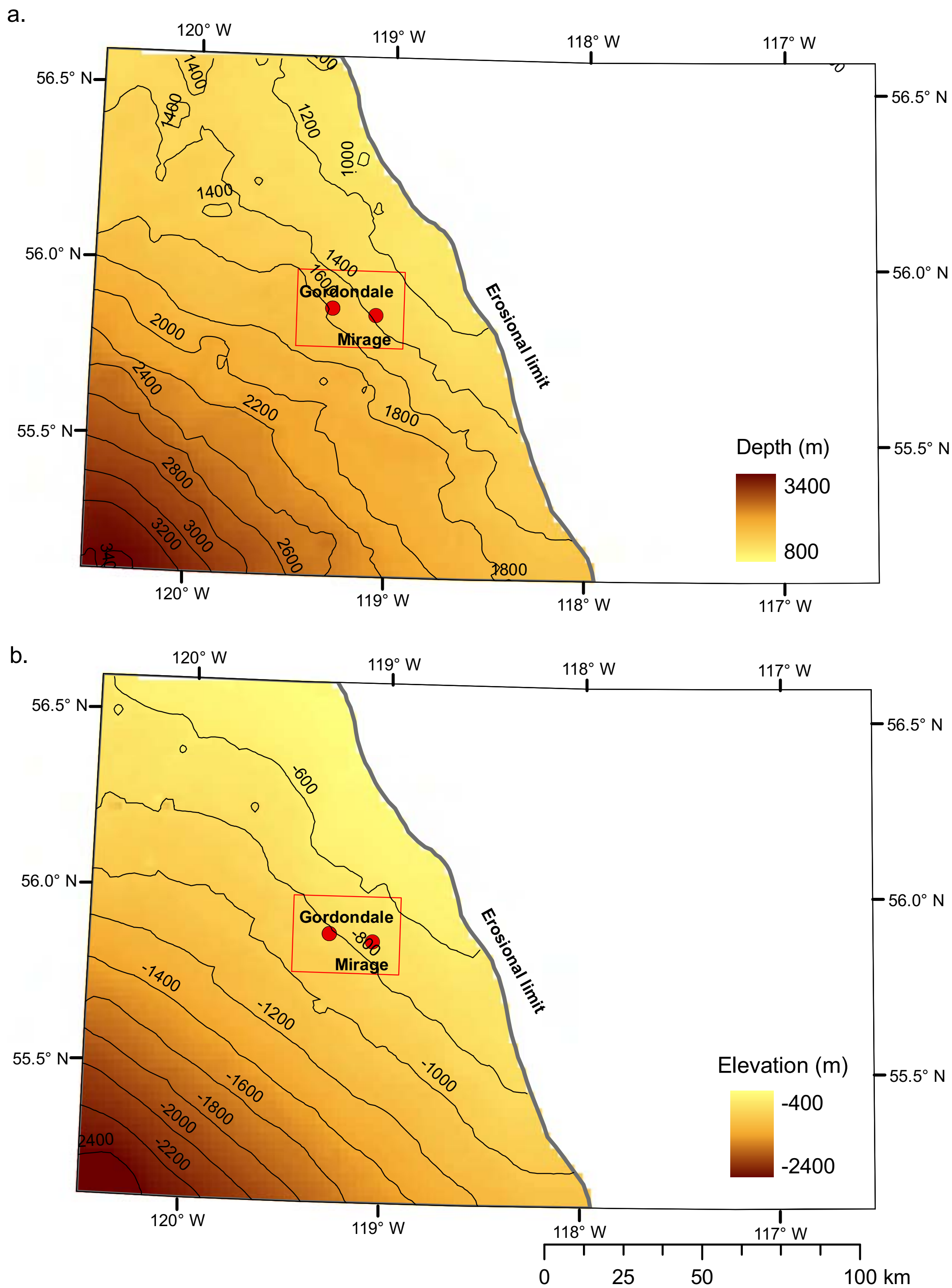


Figure 28. Main geological features of the Halfway Formation in the regional-scale study area: a) depth to top and b) structure elevation. The location of the Gordondale and Mirage injection sites and the outline of their local-scale study area (red box) are also shown.

Overlying the Halfway Formation is the Charlie Lake Formation, which represents the peak of the second T-R-cycle and comprises a succession of intercalated siliciclastics, carbonates and evaporites. The third major T-R-cycle is formed by the Baldonnel and Pardonet formations (upper Schooler Creek Group) and is dominated by shallow-water carbonates. The combined thickness of Charlie Lake to Pardonet strata ranges between 0 m along the erosional subcrop edge and more than 400 m along the deformation front of the Rocky Mountains (Figure 18).

4.3 Hydrogeology of the Upper Devonian to Bullhead Group Strata

The succession from the Devonian Woodbend Group to the Jurassic Fernie Group is the focus of the regional hydrogeological assessment because these stratigraphic units contain the targets or form seals for the eleven acid-gas injection operations in the Peace River Arch area. The Cretaceous Bullhead Group was included in the regional hydrogeological assessment, because it forms a major aquifer and is hydraulically connected directly with Triassic to Mississippian aquifers along their respective subcrop edges.

4.3.1 Hydrostratigraphy

The spatial relationships between the various aquifers and aquitards in the Peace River Arch area are shown along a southwest-northeast cross-section (Figure 29). The platform and reef carbonates of the Leduc Formation of the Woodbend Group form a semi-circular aquifer whose lateral extent is constrained inwards by the topographic high of the Precambrian crystalline basement and outwards by the basinal shales of the Ireton Formation. Coarse sandstones of the Granite Wash Formation that were deposited on the flanks of the Peace River Arch and that inter-finger with Winterburn to Beaverhill Lake strata, allow for vertical hydraulic communication between the Leduc aquifer and the underlying Swan Hills aquifer as well as the overlying Winterburn and Wabamun groups (Figure 18). In over most of the study area, the Ireton aquitard is thin or absent above the Leduc carbonates, which suggests direct hydraulic communication is possible between Leduc reefs and the Nisku Formation in the overlying Winterburn Group. The overlying carbonates of the Wabamun Group have largely aquifer characteristics; hence, the entire Devonian succession in the Peace River Arch area forms a regionally contiguous aquifer system.

The shales of the Exshaw Formation and shales and argillaceous limestones of the Mississippian Banff Formation form an aquitard between the Devonian aquifer system and the overlying aquifers. Dominantly carbonates of the Pekisko, Shunda and Debolt formations form the Rundle aquifer, which is separated by the shales of the Golata Formation from the overlying Stoddart aquifer. The sandstones of the Kiskatinaw Formation at the base of the Stoddart Group generally have well-developed porosity and permeability, whereas porosity and permeability values are lower in the overlying carbonates and anhydrites of the Taylor Flat Formation. Therefore, the Taylor Flat Formation locally may form an aquitard between the Kiskatinaw aquifer and the overlying Belloy aquifer, especially in the west of the Fort St. John Graben, where sediments of the Taylor Flat Formation are particularly thick. Towards the east and outside the graben structures, the Kiskatinaw and Taylor Flat formations form the contiguous Belloy-Stoddart aquifer with the overlying sandstones of the Permian Belloy Formation. Due to erosion, the Stoddart Group is absent in the north- and southwestern parts of the regional study area, where the Belloy aquifer is in direct contact with the underlying Rundle aquifer. The Belloy aquifer is separated from the overlying sandstones of the Triassic Halfway and Doig formations that form the Halfway-Doig aquifer by intervening shales and siltstones of the Montney Formation in the west of the Peace River Arch area. Between the limit of the Halfway-Doig aquifer and the Montney subcrop, the Montney Formation thins and the general lithofacies changes to sandstones, forming a lateral eastern continuation of the aquifer. The Halfway-Doig aquifer together with the higher permeability strata of the Montney Formation in the east forms the Middle Triassic aquifer. Mixed siliciclastics and evaporites of the Charlie Lake Formation lie on top of the Halfway Formation in the eastern half of the study area. The lower part of the Charlie Lake Formation has aquitard characteristics, whereas sandstones towards its top form in conjunction with sandstones and carbonates of the overlying Baldonnel Formation and Jurassic Nordegg Member form the Upper Triassic aquifer. In the northeast, the entire Triassic and the Jurassic Fernie Group aquitard are absent, and the Belloy and Rundle aquifers are in direct hydraulic communication with the overlying Cretaceous Bullhead aquifer. The Bullhead Group aquifer is overlain by the Fort St. John Group, which represents a thick regional shale aquitard with thin isolated sandstone aquifers.

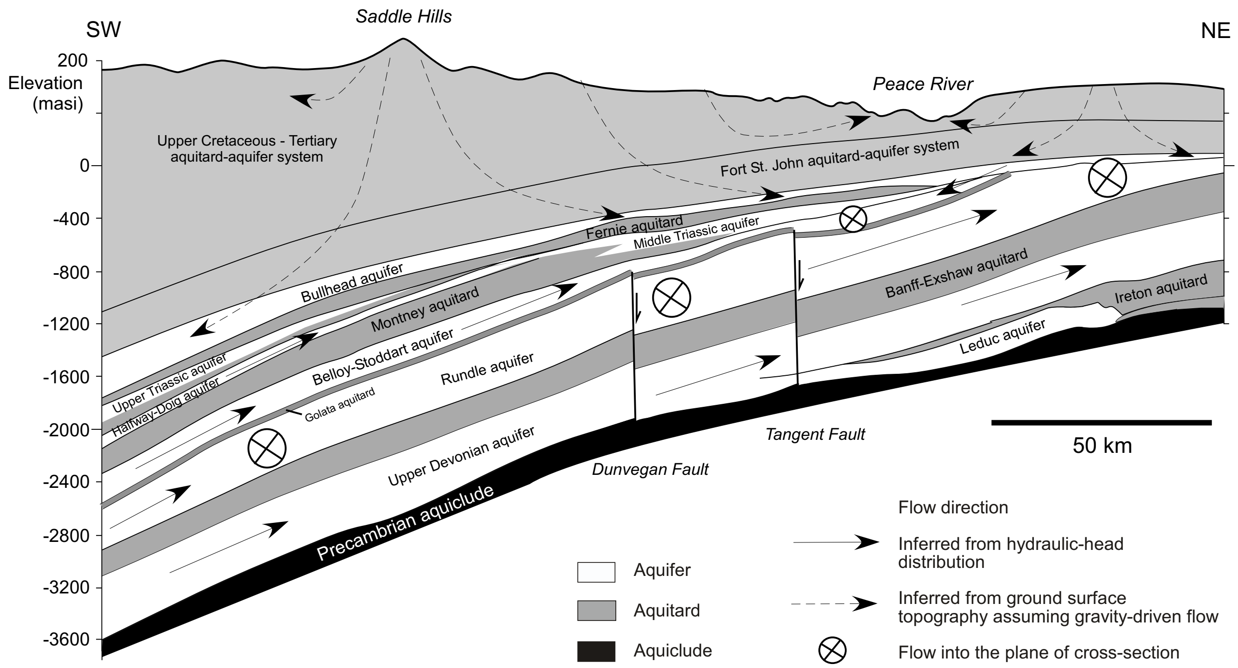


Figure 29. Diagrammatic representation of the flow systems in the sedimentary succession in the Peace River Arch area along a SW-NE cross-section. The location of the cross-section is shown in Figure 13.

4.3.2 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 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). Piper plots (chemistry), pressure-elevation plots (DST data) as well as maps showing the distribution of salinity and hydraulic heads were used in the regional hydrogeological characterization of each of the Upper Devonian to Triassic aquifers.

Table 1. Ranges of salinity (TDS) and hydraulic-head values in the various aquifers in the Peace River Arch 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	#
Granite Wash-Beaverhill Lake	163 - 298 g/l	249 g/l	88	1162 kg/m^3	440 - 660 m	563 m	115
Leduc	172 - 287 g/l	229 g/l	94	1148 kg/m^3	455 - 705 m	528 m	90
Wabamun-Wintb.	90 - 281 g/l	220 g/l	96	1143 kg/m^3	355 - 640 m	528 m	182
Rundle	12 - 261 g/l	133 g/l	69	1085 kg/m^3	330 - 630 m	464 m	196
Kiskatinaw	22 – 222 g/l	149 g/l	81	1096 kg/m^3	230 – 520 m	405 m	152
Belloy	39 - 174 g/l	123 g/l	85	1080 kg/m^3	350 - 565 m	416 m	253
Middle Triassic	23 - 220 g/l	127 g/l	247	1085 kg/m^3	345 - 920 m	496 m	271
Upper Triassic	17 – 178 g/l	110 g/l	154	1080 kg/m^3	404 – 545 m	468 m	77
Bullhead	10 - 83 g/l	29 g/l	370	1020kg/m^3	210 - 545 m	475 m	599

Chemistry of Formation Waters

Generally, formation waters in the Carboniferous to Bullhead Group aquifers in the Peace River Arch area are of a Na-Cl type, whereas Devonian and older waters are of a Na-Ca-Cl type (Figure 30). Plotting Na/Cl molar ratios versus salinity (Figure 31) distinguishes broadly between three different types of formation waters: a) relatively fresh (< 50 g/l) with wide ranges in Na/Cl ratio (Bullhead aquifer and older aquifers in area of their respective subcrop), b) medium to high salinity (50 – 225 g/l) with Na/Cl-ratios around 1 (Carboniferous to Triassic aquifers), and c) high salinity (> 175 g/l with Na/Cl ratios less than 0.8 (Devonian and older aquifers). All formation waters probably all started out as seawater but evolved differently, analogous to the evolution of brines described in the west-central part of the Alberta Basin (Michael and Bachu, 2001). Formation waters of Type 1 show various degrees of dilution with meteoric water. Type 2 waters follow the path of evaporating seawater and halite dissolution. Devonian brines of Type 3 probably underwent a high degree of water-rock interaction (albitization) in addition to the processes described for Type 2 waters. Mixing of these waters is inhibited in the western part of the study area by the combination of competent shale aquitards of the Fernie Group, Montney Formation and Banff-Exshaw formations, and weak flow-driving mechanisms in the deep parts of the stratigraphic succession. Mixing of the first two types of formation water occurs in the eastern part of the Peace River Arch area where the various Carboniferous to Lower Cretaceous aquifers are in direct hydraulic communication. Also, faults in the Fort St. John Graben Complex that penetrate the entire Palaeozoic succession form potential pathways for fluids and could be locations of mixing between the Devonian and Carboniferous brines.

On average, the salinity of formation waters increases with depth and stratigraphic age from 30 g/l in the Bullhead aquifer to 250 g/l in the Granite Wash to Beaverhill Lake aquifers (Table 1). In the Leduc aquifer, salinity values in the range of 200 to 280 g/l are highest in the centre of the southwestern flank of the aquifer (Figure 32a). Towards the east and along the northern flank, salinity values are slightly lower, ranging from 172 to 230 g/l. Similarly, in the Wabamun-Winterburn aquifer salinity in the eastern and central parts of the study area range from 170 to 280 g/l (Figure 32b). However, brines with salinity as low as 90 g/l can be found along the western and northern boundaries of the Peace River Arch area. In

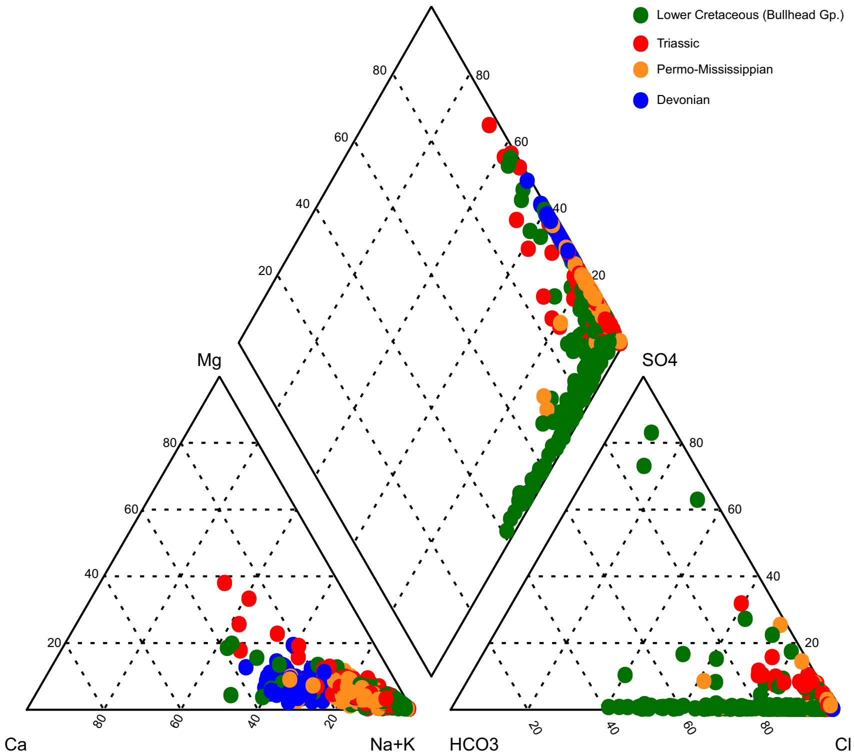


Figure 30. Piper plot of Devonian to Lower Cretaceous formation waters in the Peace River Arch area.

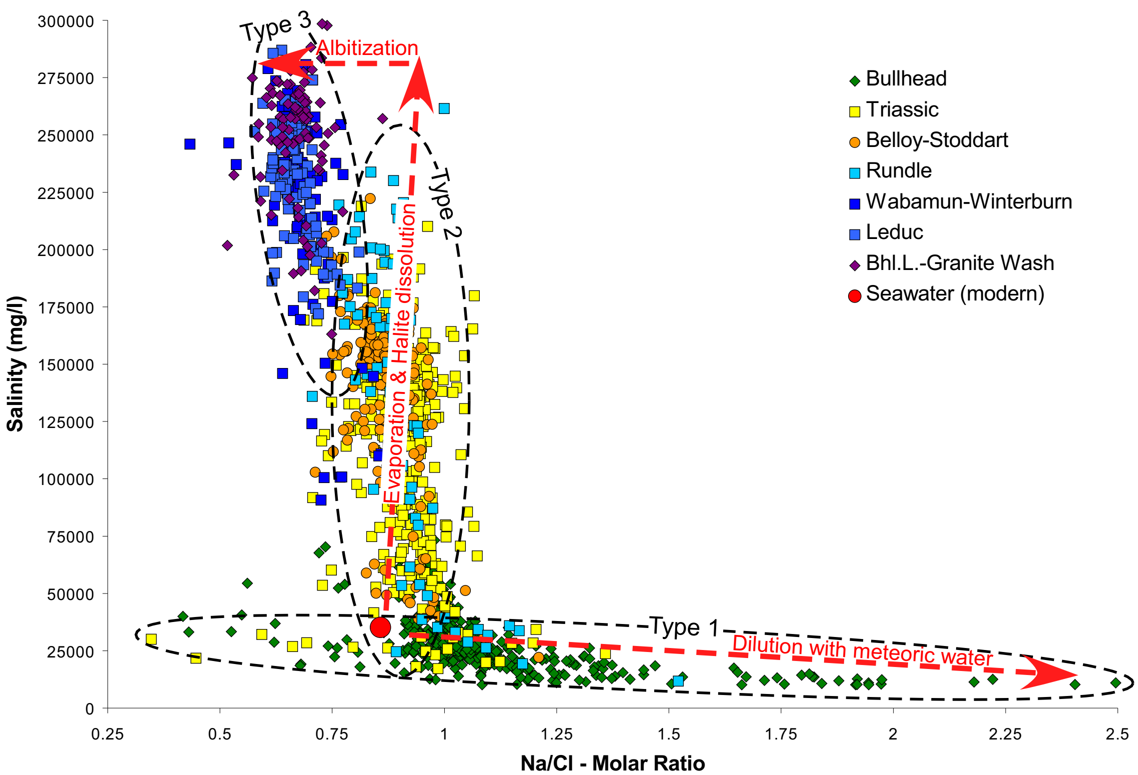


Figure 31. Grouping and schematic evolution of formation waters in the Peace River Arch area with respect to their variations in salinity and Na-Cl molar ratio.

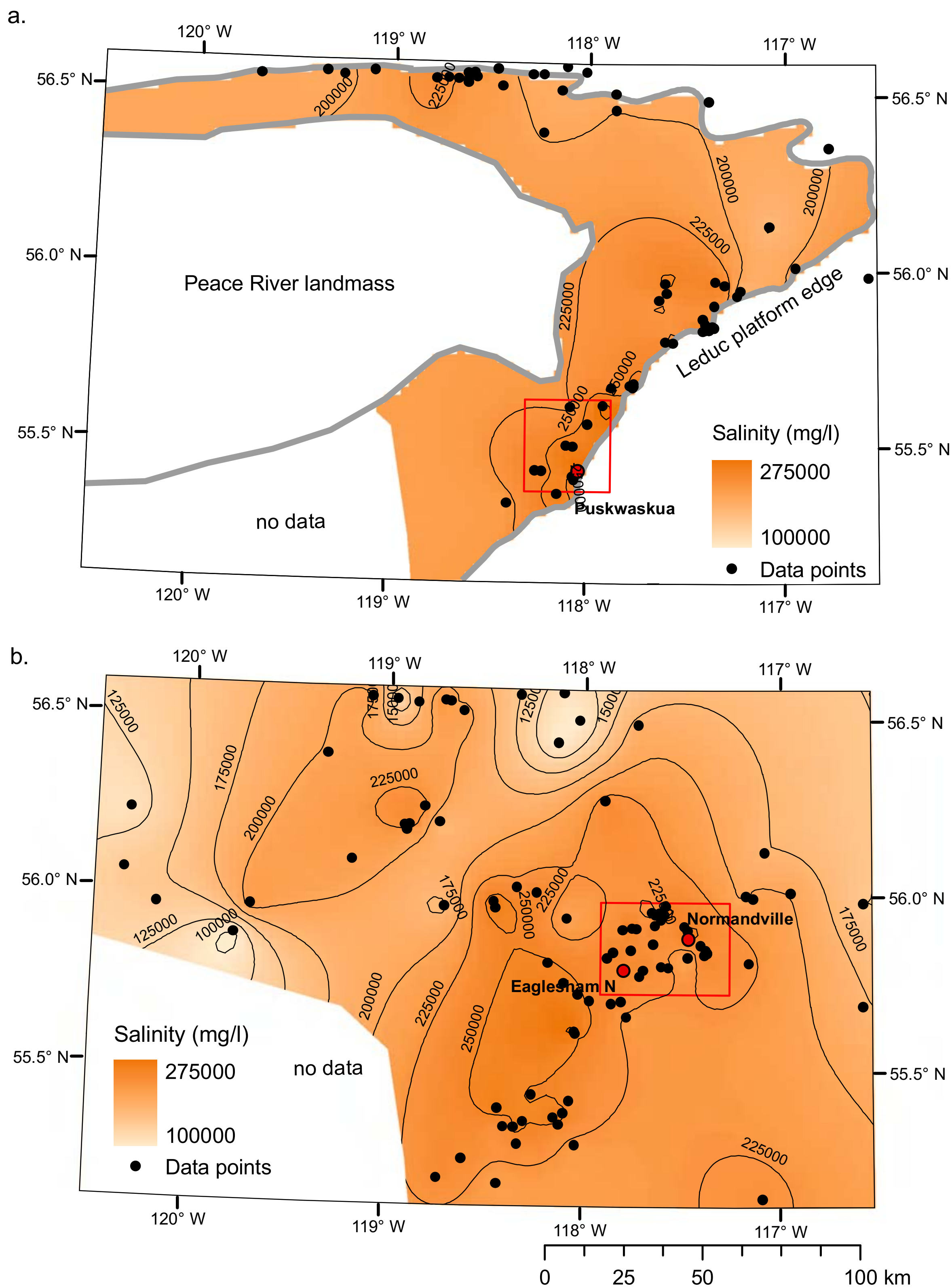


Figure 32. Regional distribution of salinity in the: a) Leduc and b) Wabamun-Winterburn aquifers. The location of the Puskwaskua (a) and Eaglesham N and Normandville (b) injection sites and the outline of their respective local-scale study areas (red box) are also shown.

the Lower Carboniferous Rundle aquifer salinity ranges widely between more than 250 g/l in the south-central part to less than 20 g/l in the northeast corner of the study area (Figure 33), where the Rundle aquifer comes into contact with the Bullhead aquifer. The pattern of salinity distribution in the overlying Kiskatinaw aquifer is similar to that in the Rundle aquifer, decreasing northeastward towards the subcrop edge (Figure 34a). However, the highest salinity values (< 200 g/l) were measured in the northwest corner of the study area within the limits of the Fort St. John Graben. Yet again, the salinity in the Belloy aquifer decreases northeastward from 200 g/l to 25 g/l (Figure 34b), values having a similar range as those in the Kiskatinaw aquifer in the northeastern half of the Peace River Arch area where both units form the Belloy-Stoddart aquifer.

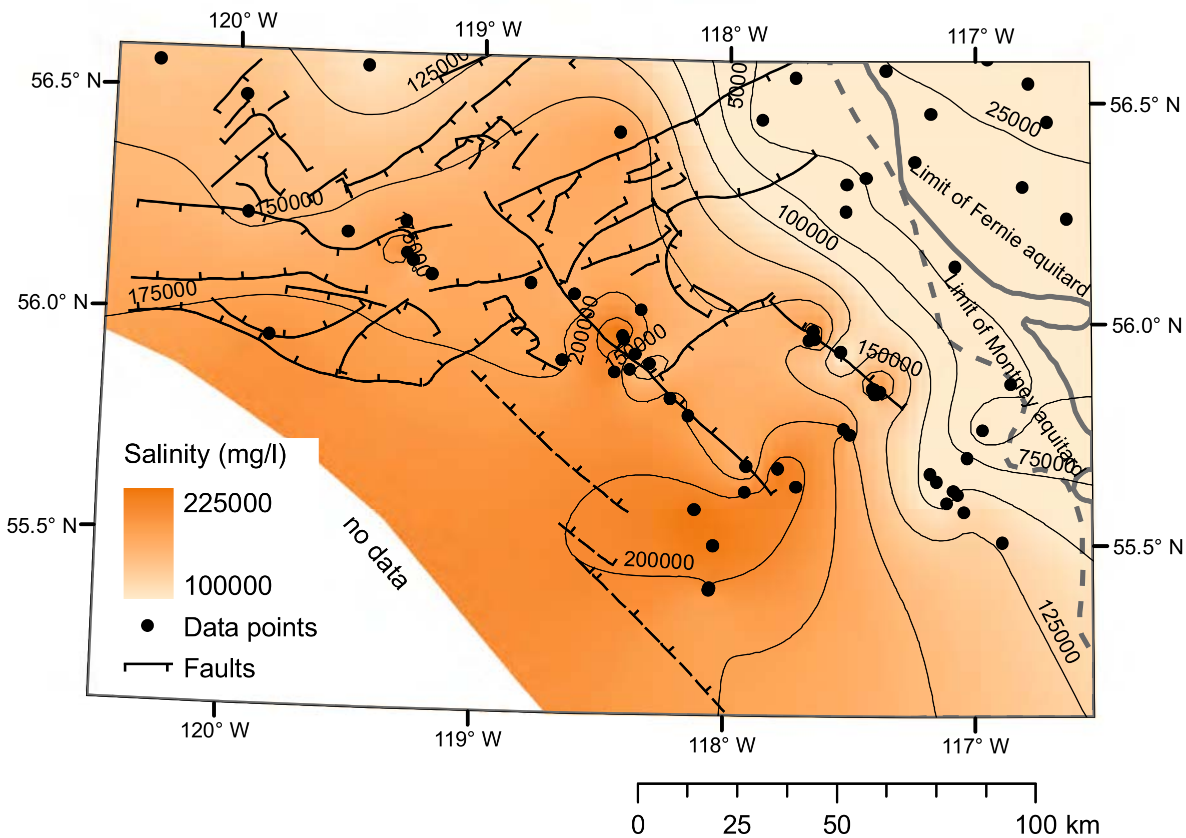


Figure 33. Regional distribution of salinity in the Rundle aquifer.

The salinity distribution and range (40 to 200 g/l) in the Middle Triassic aquifer are very similar to those in the underlying Belloy-Stoddart aquifer, again showing a freshening of formation water towards the northeast (Figure 35a). In contrast, only in the centre of the study area formation water salinity in the Upper Triassic exceeds 100 g/l (not shown). Towards the northeast and southwest, salinity decreases to less than 40 g/l. The salinity of formation water in the Bullhead aquifer ranges from less than 20 g/l along the eastern boundary and in the centre of the regional study area to approximately 80 g/l in the southwest in the foothills area of the Rocky Mountains (Figure 35b).

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

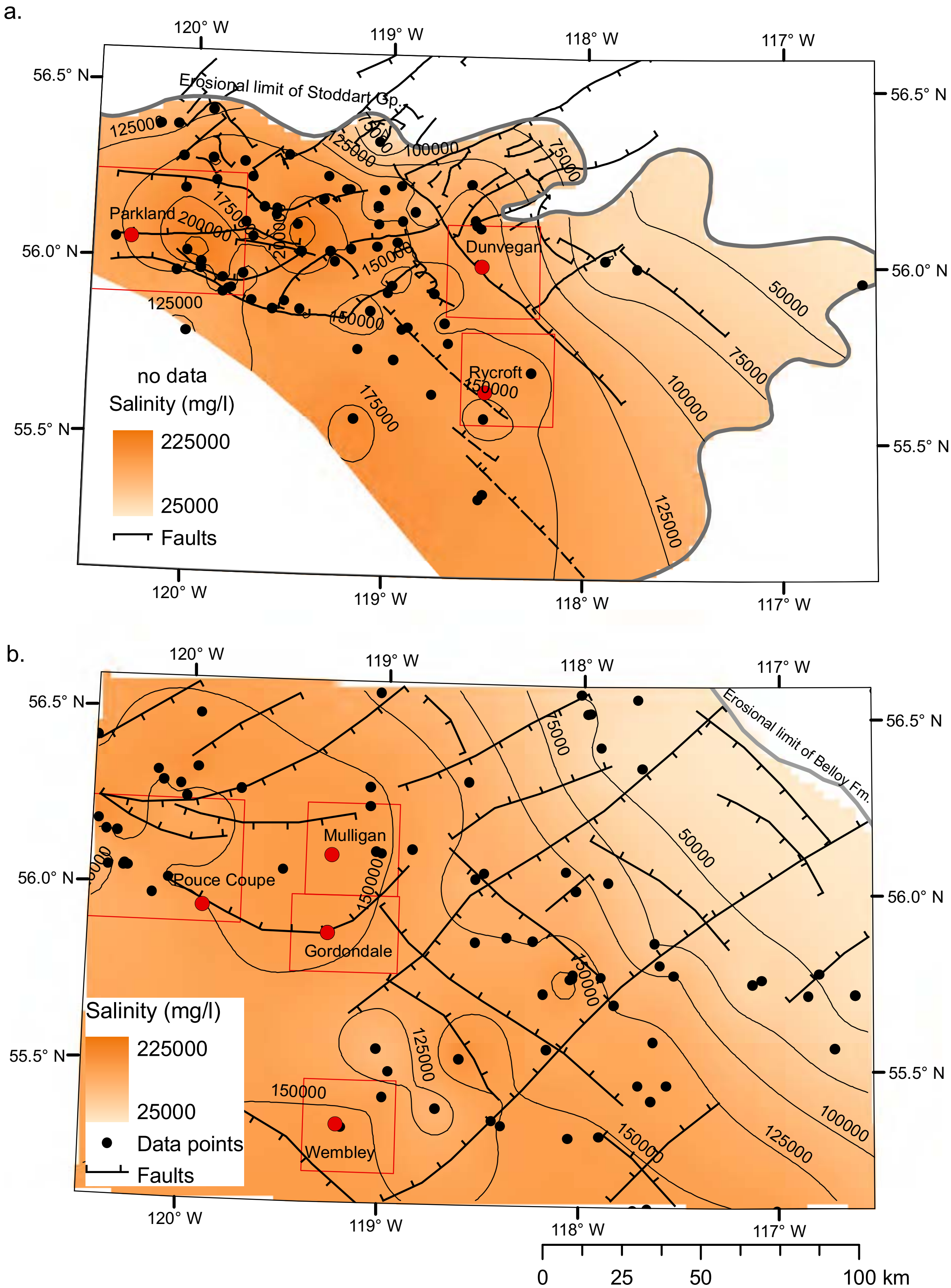


Figure 34. Regional distribution of salinity in the: a) Kiskatinaw and b) Belloy aquifers. The location of the injection sites and the outline of their respective local-scale study areas (red box) are also shown.

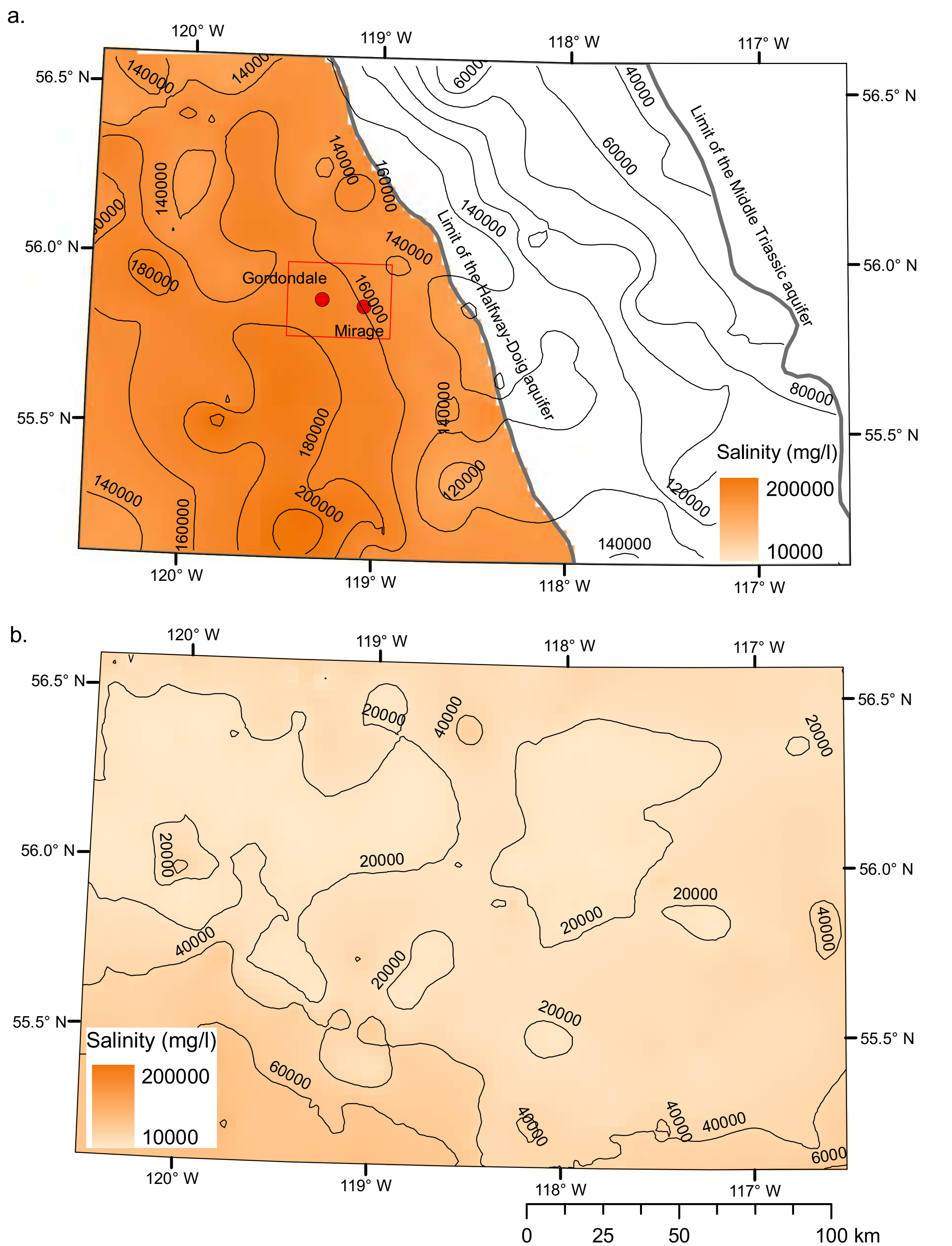


Figure 35. Regional distribution of salinity in the: a) Middle Triassic and b) Bullhead aquifers. The location of the Gordondale and Mirage injection sites and the outline of the local-scale study area (red box) is also shown.

after Rowe and Chou (1970) (Adams and Bachu, 2002). Accordingly, average formation water density increases from 1020 kg/m^3 in the Bullhead aquifer to 1162 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 Devonian to Bullhead groups. Values of hydraulic head were calculated with a reference density of 1100 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 Devonian-Bullhead Group succession in the regional study area (Table 1). The formation water density in the Bullhead aquifer is significantly lower than this average value. Still, the same reference density of 1100 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:

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

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 entire sedimentary succession indicates that all aquifers are mostly hydrostatically to sub-hydrostatically pressured (Figure 36a). Plotting pressure versus elevation reveals that there are three different pressure regimes present in the Peace River arch area (Figure 36b). The majority of the pressure data plots along a mutual trend and represents the “normal” regional pressure regime (Group I in Figure 36b)) in the Peace River Arch area created by a regional-scale, topography-driven flow system. Subtle differences of pressure-elevation trends between various aquifer systems are due to the vertical separation of aquifers by intervening aquitards. Group II is formed by pressures measured in part of the Middle Triassic aquifer that is over-pressured with respect to the surrounding aquifers and that appears to be partially isolated from the regional flow regime. Similarly, parts of the Kiskatinaw aquifer in the deep parts of the Fort St. John Graben are isolated laterally from the remainder of the aquifer and vertically from over-and underlying aquifers as indicated by pressures that plot significantly below the normal regional trend (Group III in Figure 36b).

Formation water flow inferred from hydraulic-head distributions along the southwestern flank of the Leduc aquifer is updip towards the northeast, from areas with hydraulic heads > 600 m to an area with hydraulic-head values < 500 m (Figure 37a). Along the northern flank, the hydraulic-head distribution suggests divergent flow towards the west and east, respectively. The hydraulic-head distribution in the overlying Wabamun-Winterburn aquifer suggests a general northeastward flow direction (Figure 37b). Hydraulic-head values are in the same range as those in the underlying Leduc aquifer, with the exception of a hydraulic-head low (< 400 m) in the southeast corner of the study area. In two areas, there appears to be some correlation between hydraulic-head contours and Mississippian fault traces. In the center of the study area, the 550 m contour line abruptly changes direction and follows the NW-SE strike of the Dunvegan Fault, suggesting that the fault obstructs the regional formation water flow towards the northeast. In addition, changes in the hydraulic-head pattern along the southeastern tip of the Tangent Fault in the Eaglesham area indicate deflection of formation water flow towards the southeast. The flow pattern in the overlying Rundle aquifer is markedly different. A hydraulic-head high (< 500 m) extends

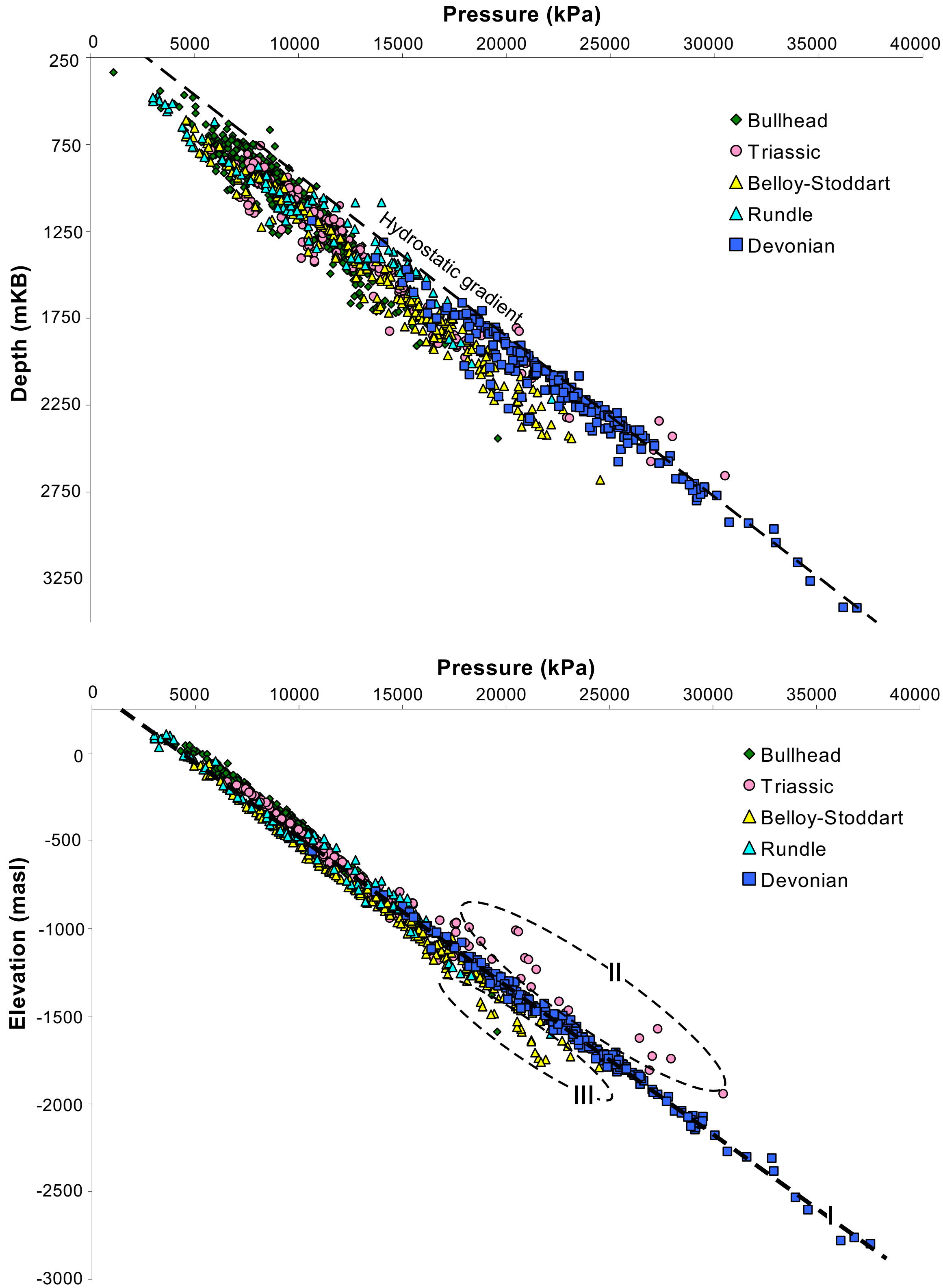


Figure 36. Distribution of pressure versus a) depth and b) elevation in the Devonian to Bullhead Group succession in the Peace River Arch area. Three pressure regimes can be distinguished: I) normally pressured, II) over-pressured, and III) under-pressured ("deep basin").

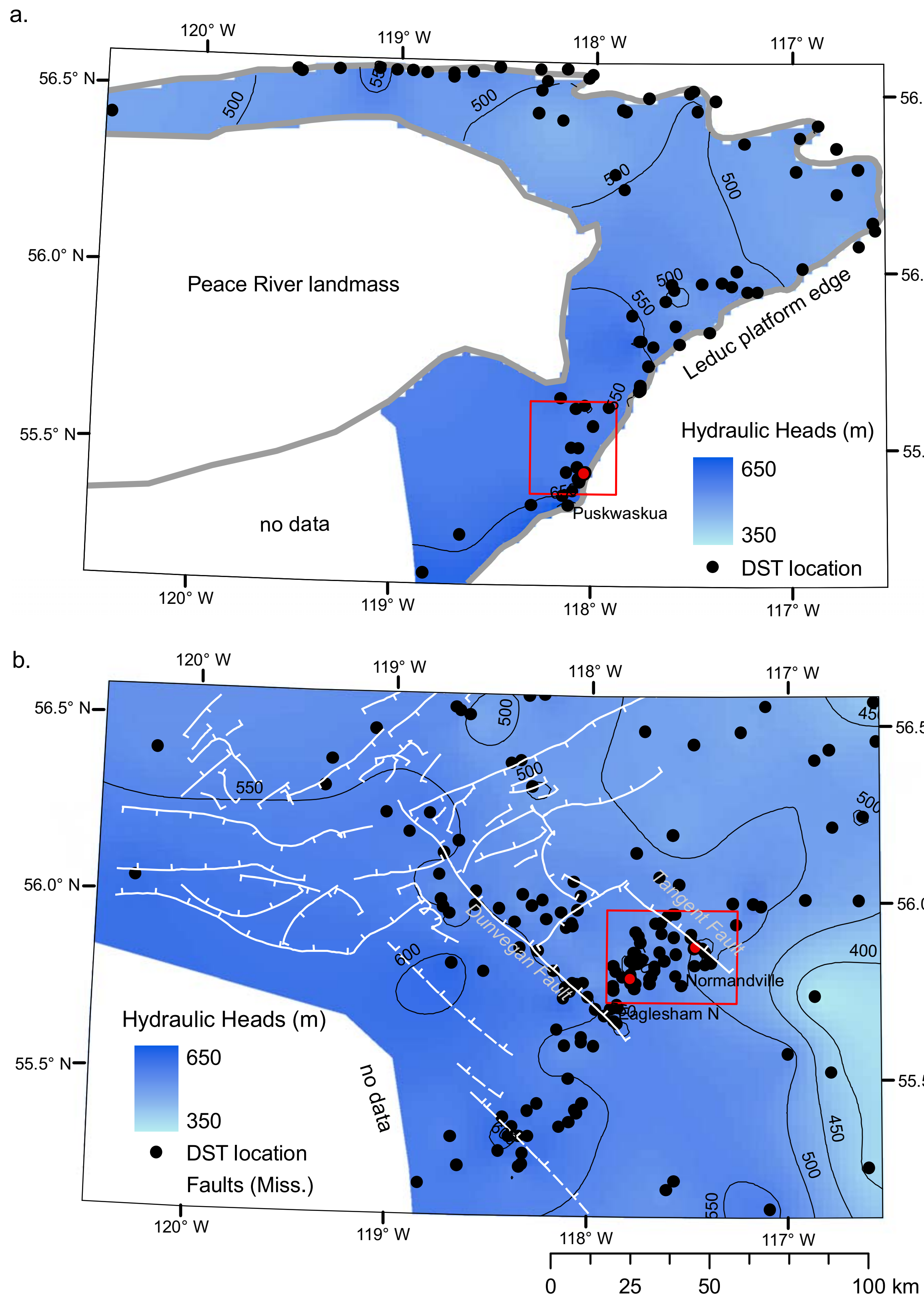


Figure 37. Regional distribution of hydraulic heads in the: a) Leduc and b) Wabamun aquifers. The location of the injection sites and the outline of their respective local-scale study area (red box) are also shown.

northward, approximately along 118° longitude, and hydraulic heads decrease towards the west, north and east, suggesting divergent flow in those directions (Figure 38). Only hydraulic-head values along the potentiometric high, which coincides with the location of the southeastern part of the Fort St. John Graben, are in the same range as those in the underlying Wabamun-Winterburn aquifer (Figure 37b), indicating the potential for vertical hydraulic communication between the two aquifers in that region. The relatively steep horizontal hydraulic gradient along the edge of the potentiometric high suggests a decrease in aquifer transmissivity, i.e., a decrease in either permeability or aquifer thickness. The hydraulic-head distributions in the overlying Belloy and Kiskatinaw aquifers (Figure 39) in the eastern half of the study area are similar and combining these two into the contiguous Belloy-Stoddart aquifer appears to be justified. In contrast, in the west of the Fort St. John Graben, where hydraulic-heads in the Kiskatinaw aquifer (Figure 39a) are significantly lower than those in the Belloy aquifer (Figure 39b), these aquifers appear to be vertically separated by the intervening Taylor Flat Formation. The anomalously low hydraulic heads < 300 m in the Kiskatinaw aquifer in this area suggest "deep basin" style underpressured conditions, and partial isolation of the Kiskatinaw aquifer in the western part of the Fort St. John Graben. The hydraulic-head distribution in the Belloy and Kiskatinaw aquifers show a completely reversed flow pattern from that in the Rundle aquifer.Hydraulic heads generally decrease from > 425 m along the western, southern and eastern boundary to approximately 375 m in the north, indicating north-northeastward channelled flow of formation water in the center of the study area. Particularly in the central area, where the difference between hydraulic head values in the Rundle and Belloy-Stoddart aquifers is larger than 100 m, the intervening Golata aquitard appears to be an effective barrier to vertical flow. Conversely, in the west, and along the northern and eastern boundaries, hydraulic heads are similar and the possibility of cross-formational flow exists. The horizontal hydraulic gradient in the Belloy and Kiskatinaw aquifers is relatively low in most of the study area, suggesting a homogeneous permeability distribution and good lateral aquifer hydraulic continuity. In most of the Peace River Arch area hydraulic heads in the Halfway-Doig aquifer (western part of the Middle Triassic aquifer) (Figure 40a) are significantly higher than values in the underlying Belloy-Stoddart aquifer, confirming that the intervening Montney aquitard effectively retards cross-formational flow of formation water. Only in the area between the respective erosional edges of the Halfway-Doig formations and the Montney Formation, the Montney Formation thins and, with increasingly higher permeability due to lateral lithofacies changes (Figures 27a and 31), changes eastward into an aquifer. Similar ranges of hydraulic head values suggest that both aquifers are in direct hydraulic communication in this area. Hydraulic-head values in the Middle Triassic aquifer range widely from 350 m to approximately 850 m (Figure 40a). The area of the aquifer in the southwest, where hydraulic head values above 600 m are observed, appears to be partly isolated from the remainder of the aquifer as indicated by the relatively steep hydraulic gradient. In the remainder of the Halfway-Doig aquifer, hydraulic heads are generally between 460 m and 500 m, decreasing only to less than 400 m along the subcrop edge in the southeast. This pattern of hydraulic head distribution suggests good lateral aquifer continuity in most of the aquifer. The flow of formation water is directed away from the center of the Peace River Arch area and away from the overpressured region in the southeast towards the northeast, southeast, and northwest corners, as well as towards the potentiometric low at the southern boundary of the study area. Hydraulic head values in the Upper Triassic aquifer (not shown) have a narrow range of 460 to 500 m in most of the study area, with exception of the southwest corner, were head values decrease below 450 m. The hydraulic-head distribution in the Bullhead aquifer does not show major regional trends, values generally ranging between 450 and 500 m (Figure 40b). A hydraulic-head low with values as low as 210 m is present in the southwest corner of the Peace River Arch area.

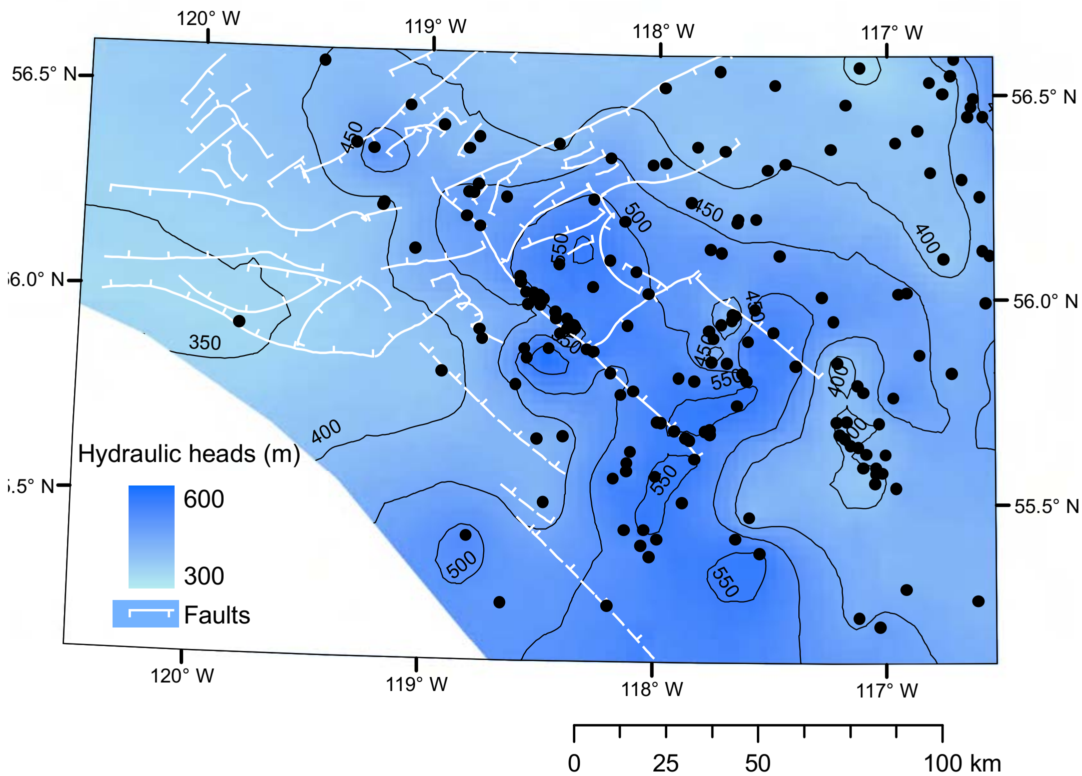


Figure 38. Regional distribution of hydraulic heads in the Rundle aquifer.

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:

- Seven regional aquifers can be distinguished in the study area: Leduc, Wabamun-Winterburn, Rundle, Belloy-Stoddart, Middle Triassic, Upper Triassic and Bullhead.
- The bounding and intervening aquitards are: Ireton, Exshaw-Banff, Golata, Montney, lower Charlie Lake, Fernie, and Fort St. John-Wilrich.
- None of the aquitards (except for the Fort St. John-Wilrich) is laterally contiguous in the regional study area, allowing for direct hydraulic communication between various aquifers in certain regions.
- The salinity of formation waters varies over a wide range, from approximately <10 g/l in the shallowest aquifer in the southwest to >225 g/l in the center of the regional-scale study area.
- Where the Fernie and/or Montney aquitards are absent, brines from the various Triassic to Carboniferous aquifers mix along their subcrops with fresher formation water from the Bullhead aquifer.
- Relatively fresher formation water enters the various aquifers from the Rocky Mountain Foothills in the southwest and flow is generally updip in a north-northeastward direction in the southwest half of the study area.
- Thickening of the Belloy-Stoddart strata in the center of the various grabens due to syn-sedimentary faulting resulted in increased aquifer transmissivity and in channelling of formation water, particularly along the Fort St. John Graben.
- Generally, faults appear to restrict or channel lateral flow within aquifers, but there is no indication for faults creating vertical flow paths between aquifers.

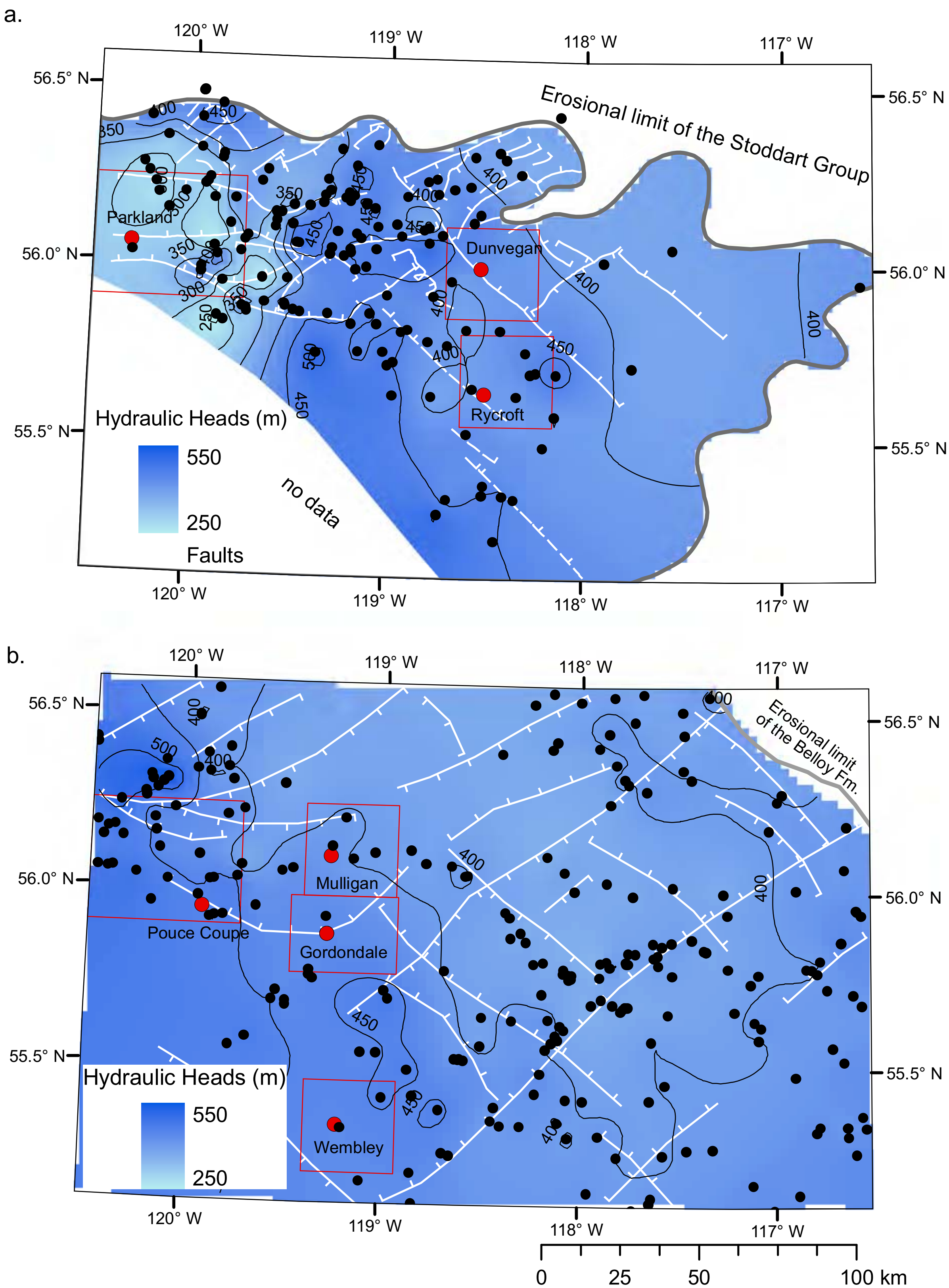


Figure 39. Regional distribution of hydraulic heads in the: a) Kiskatinaw and b) Belloy aquifers. The location of the injection sites and the outline of their respective local-scale study areas (red box) are also shown.

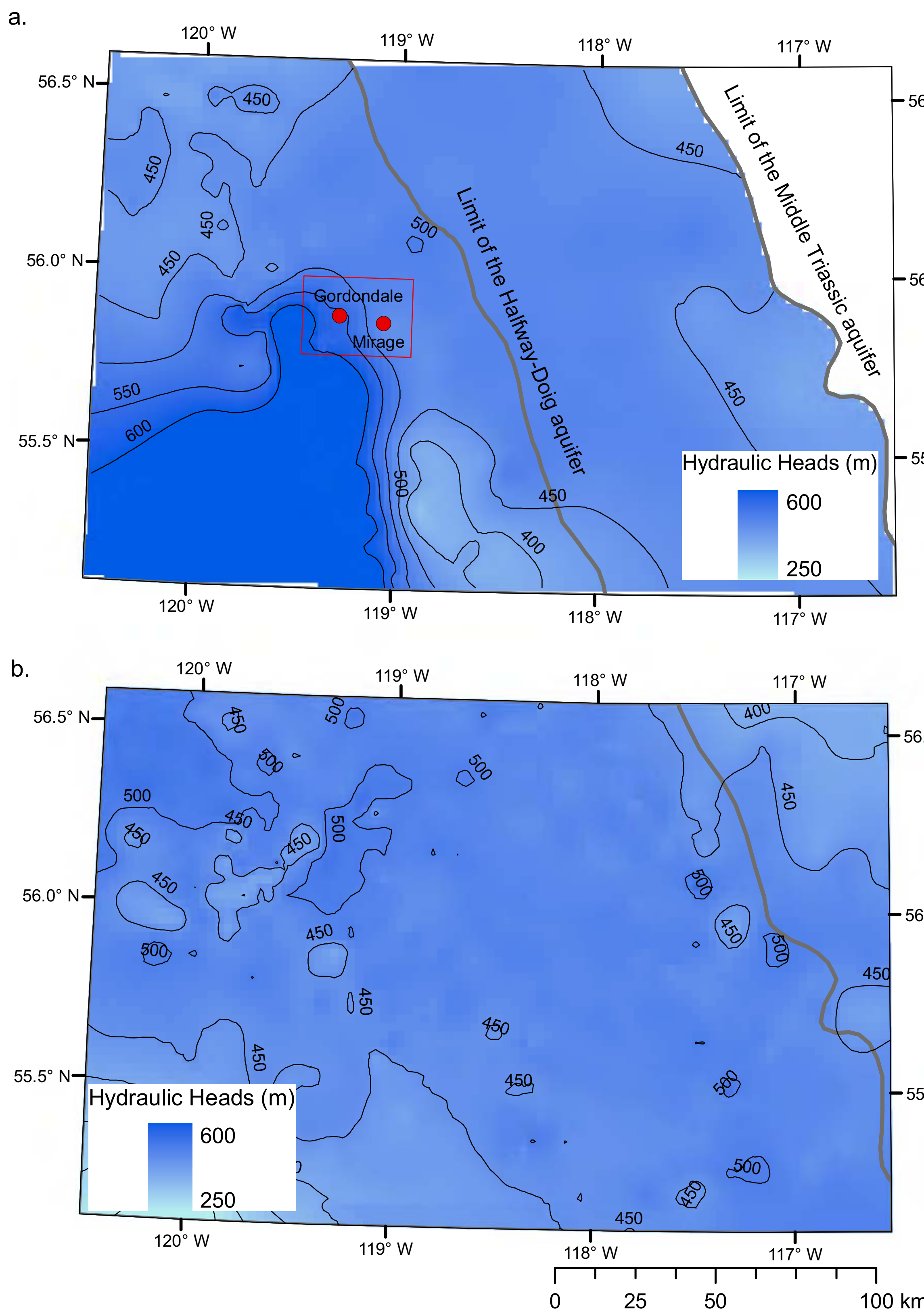


Figure 40. Regional distribution of hydraulic heads in the: a) Middle Triassic and b) Bullhead aquifers. The location of the Gordondale and Mirage injection sites and the outline of the local-scale study area (red box) are also shown.

4.3.3 Flow Interpretation

Present-day formation water flow in the Devonian to Triassic aquifers in the regional study area is mainly updip, towards the northeast (Figure 29), driven by regional-scale topography (Hitchon et al., 1990). The common 'sink' for updip flow in the Devonian aquifers is the 'Grosmont drain' to the northeast of the study area (Hitchon *et al.,* 1990; Bachu, 1999). Flow in the Mississippian to Triassic aquifers converges with flow in the Bullhead aquifer (Figure 29) and ultimatively discharges at Bullhead Group outcrops along the Peace River to the north-northeast. Due to graben geometry, lithofacies changes and subcrop of the various aquifers flow patterns in individual aquifers may diverge from the general direction of this regional flow regime. Particularly in the southwest corner of the study area, anomalous pressures in the Bullhead, Upper Triassic and Middle Triassic aquifers suggest that this area is largely isolated from the regional, topography-driven flow system. Triassic to Cretaceous strata in the southwest corner of the Peace River Arch study area lie within the outline of the "deep basin" Masters, 1984), a mainly hydrocarbon-saturated region with abnormal pressures. Fluids can be either overpressured (i.e., Triassic Halfway-Doig formations) or underpressured (i.e., Bullhead Group). Hence, the downdip flow component in the southeastern corner of the Bullhead 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, 1995a) or decreasing horizontal stresses after the Laramide orogeny (Bell and McCallum, 1990). Another region with underpressures, although not hydrocarbon-saturated, is located within the down-faulted part of the Kiskatinaw aquifer in the Fort St. John Graben in the northwest of the Peace River Arch area.

With the exception of the "deep basin" part in the southwest of the study area, the Bullhead aquifer and the thin aquifers in the Fort St. John aquitard-aquifer system belong to an intermediate flow regime. Flow of formation water is driven by regional- to local-scale topography, the latter having a more predominant effect on flow in the shallower aquifers.

Throughout most of the Devonian to Bullhead Group succession, the maximum salinity is found in the south-central part of each aquifer. Tongues of fresher water in the west of the various aquifers suggest that recharge in the mountains to the east results in various degrees of mixing between water of meteoric origin and original brine. The overall low salinities of formation water in the Mississippian to Triassic succession in the northeast are due to the mixing with low-salinity water in the Bullhead aquifer along the sub-Cretaceous unconformity where the intervening Fernie, Charlie Lake, and Montney aquitards are absent. However, these three aquitards form effective barriers to cross-formational flow in the western half of the Peace River Arch area. The Banff-Exshaw aquitard is present everywhere in the Peace River Arch area, preventing the mixing of Devonian brines with formation water from overlying aquifers.

With respect to the regional hydrostratigraphy and hydrogeology, the acid-gas injection targets in the Peace River Arch area are in ascending stratigraphic order in: a) platform carbonates in the Leduc aquifer (Puskwaskua), b) dolomitized patch reefs (Normandville and Eaglesham) in the Wabamun aquifer, c) and shallow-marine sandstones of Carboniferous (Rycroft, Parkland, Dunvegan) and Permian (Gordondale-Belloy, Wembley, Pouce Coupe, Mulligan).age in the Belloy-Stoddart aquifer, and d) marine sandstones in Middle Triassic aquifer (Gordondale-Halfway, Mirage).

4.4 Stress Regime and Rock Geomechanical Properties

Knowledge of the stress regime at any injection site is important for assessing the potential for hydraulic rock fracturing and re-activation of faults 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:

$$P_b = 3S_{H\min} - S_{H\max} + P_0 + {}_0 \qquad (2)$$

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 tensile strength (Hubbert and Willis, 1957). In the case of injection, the fluid pressure at the well is the bottomhole 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.

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:

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

where S_V is the vertical stress and ν is Poisson's ratio, which is determined through laboratory tests on rock samples (e.g., Bell, 2003). 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 tensile strength, 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 Peace River Arch area exist in the public domain (i.e., operator applications to EUB). Fracturing tests (mini-frac and hydro-frac) 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 performed mainly in Cretaceous and Triassic 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 Peace River regional-scale study area.

Well Location	Formation	Test Type	Depth (m)	Grad(S) (kPa/m)
C-016-I/093-P-01	Paddy Member	Mini-frac	2095	16.0
C-016-I/093-P-01	Cadotte Formation	Mini-frac	2128	18.0
C-016-K/093-P-01	Cadotte Formation	Hydro-Frac	2181.3	12.6
11-12-071-13W6	Spirit River Formation	Micro-frac	2021	20.0
B-036-K/093-P-01	Falher Member	Hydro-Frac	2241.5	17.4
10-17-083-08W6	Bluesky Formation	Hydro-Frac	1002	14.0
15-19-086-07W6	Gething Formation	Hydro-Frac	884.5	18.1
13-15-081-10W6	Gething Formation	Hydro-Frac	1236.75	17.8
08-30-086-07W6	Gething Formation	Hydro-Frac	912.5	16.4
08-26-081-08W6	Gething Formation	Hydro-Frac	1040	17.3
C-016-I/093-P-01	Gething Formation	Mini-frac	2669	17.0
C-016-I/093-P-01	Cadomin Formation	Mini-frac	2717	16.0
13-82-016-20W1	Halfway Formation	Hydro-Frac	1501.5	14.7
D-019-H/093-P-09	Halfway Formation	Hydro-Frac	2357.5	12.1
11-31-082-13W6	Halfway Formation	Hydro-Frac	1539	16.9
02-13-087-13W6	Halfway Formation	Hydro-Frac	1383.5	15.9
/01-26-085-14W6	Halfway Formation	Hydro-Frac	1394.8	17.9
01-08-087-13W6	Halfway Formation	Hydro-Frac	1452	13.8
08-25-077-10W6	Halfway Formation	Mini-frac	1870	17.0
D-019-H/093-P-09	Doig Formation	Hydro-Frac	2357.5	15.3
06-01-082-13W6	Doig Formation	Hydro-Frac	1580	12.7
13-02-082-13W6	Doig Formation	Hydro-Frac	1568.2	15.9
11-26-078-11W6	Doig Formation	Mini-frac	1855	18.4
D-044-G/093-P-09	Montney Formation	Hydro-Frac	2764.5	19.5
A-029-H/093-P-09	Montney Formation	Hydro-Frac	2676.3	20.6
09-34-079-13W6	Montney Formation	Hydro-Frac	1810.8	13.8
08-09-085-14W6	Belloy Formation	Hydro-Frac	1706	20.5
13-30-078-13W6	Kiskatinaw Formation	Hydro-Frac	2597.5	18.1

The fracture tests indicate a gradient of the minimum horizontal stress of 12.1 to 20.5 kPa/m (Table 2). Interpolation of the data results in an average of 17.1 kPa/m for the gradient of S_{Hmin} compared to 23.6 kPa for the vertical stress gradient (Figure 41).

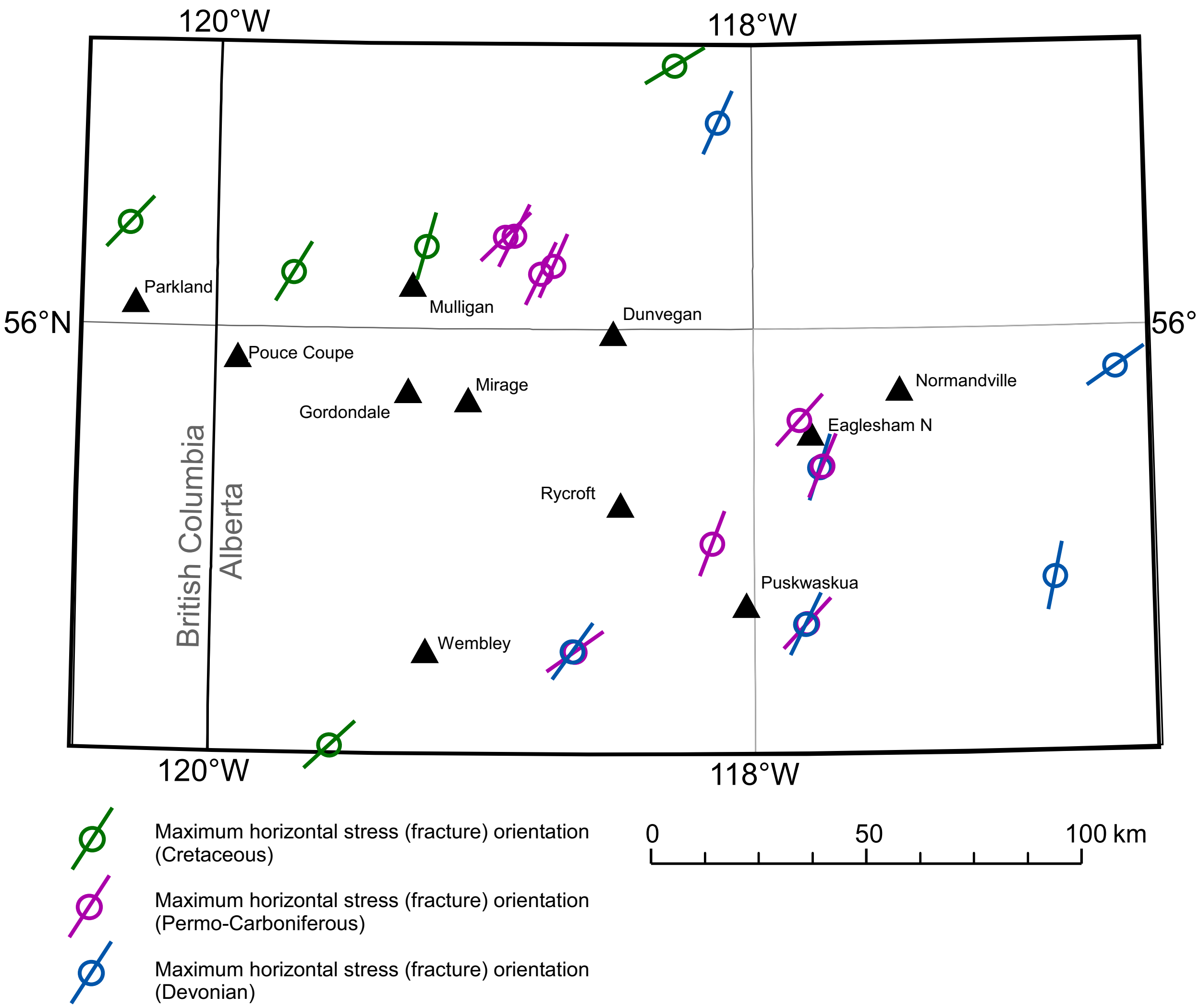


Figure 41. Orientation of horizontal stresses in Devonian to Lower Cretaceous strata in the regional-scale study area.

Orientations of the minimum horizontal stress, S_{Hmin}, were determined from breakouts in twenty-five wells in the regional-scale study area (Table 3 and Figure 41). The direction of the minimum horizontal stress varies between 102.7° and 146.8° (average 124.5°), in a general west-northwest to east-southeast direction. This means that induced fractures over the Peace River Arch will form and propagate in a vertical plane in a north-northeast to south-southwest direction (12.7° to 56.8°; average 34.8°). This direction is a slight deflection from the southwest-northeast azimuth of the maximum horizontal stress observed in other parts of the Alberta Basin, probably due to the lateral heterogeneity in the elastic rock properties (Bell and McCallum, 1990).

There are two issues related to faults in the Peace River Arch area that may affect migration of fluids and the safety of injection operations. Firstly, faults, if open, may act as vertical fluid pathways through otherwise low-permeability strata. In the present-day compressional stress regime, only faults in the direction of the maximum horizontal stress (north-northeast to south-southwest) would have the potential to open up and to form a flow conduit. The majority of faults, especially in the centre and in the eastern part of the Dawson Creek Graben Complex, where acid-gas injection occurs, have a WNW-ESE or NW-SE direction and are not likely to open. Secondly, faults represent zones of weakness in the rock framework and the re-activation of faults caused by a decrease in effective stress due to fluid injection may induce earthquakes. Earthquakes as large as magnitude 4.3 (Richter Scale) have been measured in the Fort St. John region since 1984 and have been attributed to high-pressure water injection into the Belloy Formation in the Eagle and Eagle West fields (Horner et al., 1994). For comparison, surface injection pressures of up to 25 MPa in the Eagle Field are more than double the approved injection pressures for acid-gas operations in the Peace River Arch area.

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

Well Location	Stratigraphic Age	S_{Hmin} Azimuth	S_{Hmax} Azimuth
00/10-11-071-11W6/0	Upper Cretaceous	133.80	43.80
00/16-24-082-12W6/0	Cretaceous	117.20	27.20
00/03-08-083-08W6/0	Cretaceous	104.60	14.60
00/07-29-083-15W6/0	Cretaceous	129.70	39.70
00/10-11-071-11W6/0	Lower Cretaceous	133.80	43.80
00/13-20-087-02W6/0	Lower Cretaceous	146.80	56.80
00/11-22-073-05W6/0	Permian	144.20	54.20
00/11-22-073-05W6/0	Carboniferous	129.10	39.10
00/08-31-074-25W5/0	Carboniferous	131.60	41.60
00/11-01-076-02W6/0	Carboniferous	112.20	22.20
00/09-35-077-25W5/0	Carboniferous	114.80	24.80
00/11-29-082-05W6/0	Carboniferous	115.80	25.80
00/10-17-083-06W6/0	Carboniferous	135.80	45.80
00/09-18-083-06W6/0	Carboniferous	116.20	26.20
00/08-04-079-25W5/0	Carboniferous	130.30	40.30
00/12-24-082-06W6/0	Carboniferous	113.60	23.60
00/11-22-073-05W6/0	Upper Devonian	125.20	35.20
00/08-31-074-25W5/0	Upper Devonian	114.90	24.90
00/09-35-077-25W5/0	Upper Devonian	109.20	19.20
00/13-07-080-17W5/0	Upper Devonian	145.10	55.10
00/07-07-086-01W6/0	Upper Devonian	114.30	24.30
00/10-08-075-19W5/0	Middle Devonian	102.70	12.70

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 Peace River Arch 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 in the regional study area and its vicinity. Measurements in each case cover a number of 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. Three of the values given represent parameters measured in Mississippian carbonates. Shale and chert caprock values are represented by measurements taken in the Jurassic Fernie Group and Nordegg Member, respectively. No data for Triassic and Permian strata were available. Therefore, the sandstone injection interval is characterized by sandstones from the Basal Quartz Formation and the Bluesky Formation, which are equivalent to the Cretaceous Bullhead Group.

Table 4. Geomechanical properties of rocks of interest from the Alberta Basin (based on data from McLennan *et al.*, 1982; Miller and Stewart, 1990; Wang *et al.*, 1991; and McLellan and Cormier, 1996).

Formation	**Rock Type**	**Latitude**	**Longitude**	**Depth** (m)	**Poisson's Ratio**	**Young's Modulus** (GPa)
Fernie Fm.	shale	55.4557	-122.2174		0.28	28.3
Debolt (?)	carbonate	56.4753	-119.9095		0.29	54.2
Debolt (?)	carbonate	58.2941	-119.2714		0.34	54.3
Pekisko Fm.	limestone	52.3611	-114.4178	2195	0.31	63.8
Bluesky Fm.	sandstone	54.6201	-118.3704	2308	0.25	35.7
Basal Quartz	sandstone	51.9863	-114.8608	3030	0.19	44.9
Nordegg Mbr.	Ss, ls, chert	52.3575	-114.4358	2196	0.24	54.03

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 Mississippian carbonates range from 47 GPa to 72 GPa (Miller and Stewart, 1990; Wang *et al*., 1991), compared with values of 30 GPa to 63 GPa for the Basal Quartz sandstone (McLennan *et al*., 1982) and 13 GPa to 45 GPa for the Fernie shale (McLellan and Cormier, 1996).

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 0.1 to 0.3, and for shales from 0.1 to 0.4 (Lambe and Whitman, 1979; Jumikis, 1983; Haas, 1989). The Poisson's ratio for Mississippian carbonates ranges from 0.23 to 0.34 (Miller and Stewart, 1990; Wang *et al*., 1991), compared with values of 0.13 to 0.33 for the Basal Quartz sandstone (McLennan *et al*., 1982) and 0.14 to 0.44.for the Fernie shale (McLellan and Cormier, 1996).

5 Local-Scale Setting Of the Acid-Gas Injection Sites in the Peace River Arch Area

The acid-gas injection sites in the Peace River Arch area are distributed over a large area and various stratigraphic intervals, which have variable characteristics. Therefore, the geological and hydrogeological characteristics of the 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 11 injection operations were therefore studied in eight local-scale study areas (Table 5).

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

Local-Scale Study Area	Site Name	Injection Well Location	Latitude	Longitude
Normandville	Normandville-Wabamun	13-25-079-23-W-5	55.8820	117.4670
	Eaglesham-Wabamun	06-34-078-25-W-5	55.8017	117.7932
Puskwaskua	Puskwaskua-Leduc	14-23-074-01-W-6	55.4317	118.0409
Rycroft	Rycroft-Kiskatinaw	07-02-077-04-W-6	55.6419	118.5038
Dunvegan	Dunvegan-Kiskatinaw	06-12-081-04-W-6	56.0062	118.4855
Wembley	Wembley-Belloy	06-19-073-08-W-6	55.3355	119.2211
Mulligan	Mulligan-Belloy	15-11-082-09-W-6	56.0983	119.2880
Gordondale	Gordondale-Belloy	10-26-079-09-W-6	55.8783	119.2917
	Gordondale-Halfway	09-23-079-09-W-6	55.8620	119.2857
	Mirage-Halfway	08-19-079-07-W-6	55.8583	119.0766
		14-19-079-07-W-6	55.8658	119.0876
		08-25-079-08-W-6	55.8721	119.1022
Pouce Coupe	Parkland-Kiskatinaw	15-17-081-15-W-6	56.0263	120.3041
	Pouce Coupe-Belloy	05-23-080-13-W-6	55.9470	119.9286

At Mirage and Gordondale, acid gas was injected into Halfway oil pools between 1995 and 1999, but both operations were rescinded. At Gordondale, the operator switched to injecting acid gas into the Belloy Formation in the Belloy-Stoddart aquifer. The Belloy-Stoddart aquifer is also the injection target at Mulligan, Pouce Coupe, Rycroft and Wembley. Acid gas is injected into depleted oil or gas reservoirs at the remainder of the operations in the Peace River Arch area.The geology in these specific areas is moderately well known and understood, because drill core, albeit in limited numbers, is available as a result of exploration for and production of hydrocarbons from Triassic to 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 20, 22, 24, 26 and 28). In turn, isopach maps and/or local-scale cross-sections are shown, since information about the thickness of the injection unit and the overlying aquitard is relevant at the local scale. Isopach maps are based on existing stratigraphic data stored in AGS/EUB databases that were culled for consistency and erroneous values. The stratigraphic delineations along the various local-scale cross-sections are based on the interpretation of geophysical well logs in selected wells by Dong Chen of the Mapping Section at the AGS.

Identification and Graphical Representation of Faults

The locations of faults as shown in the cross-sections and isopach maps are largely adopted from interpretations by Richards et al. (1994, Figure 14.5) and Henderson et al. (1994, Figure 15.1). Their fault traces are based on stratigraphic data and some seismic interpretation. Richards et al. (1994) and Henderson et al. (1994) mapped the faults on a regional scale for the entire Peace River Arch area and reproducing the fault traces on smaller-scale maps in the local-scale study areas is associated with some inaccuracies. Therefore, for this report the locations of faults in the local-scale study areas were adjusted in some cases to fit the new stratigraphic data (top of the Carboniferous Debolt Formation) and finer map resolution. Only in a few cases, is was necessary to add an additional fault, either because its expression could only be detected locally, or because it had been specifically identified in the application for an acid-gas injection operation. It should be noted that the accuracy of the location of faults is dependent on the distance between wells in which the stratigraphic horizon was picked. No exact values for fault dips were available for this study and the fault dips shown in the various cross-sections are somewhat schematic. Still, tracing the offset along faults through different stratigraphic horizons and inspecting seismic cross-sections indicates that the majority of faults are very steep (< 10° from vertical).

Calculation of Hydraulic-Head and Rock Property Values

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 1100 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 Puskwaskua

The Puskwaskua local-scale study area is defined between 55.37°N to 55.63°N and 117.88°W to 11.31°W (Townships 74-76, Ranges 26W5-2W6). Injection of acid gas takes place into platform carbonates of the Leduc Formation in the depleted Puskwaskua D-3 A pool (Figure 42a, Appendix 1).

5.1.1 Geology

Generally, the platform carbonates of the Leduc Formation range in thickness between 50 and 210 m (Figure 42a). The Puskwaskua injection site is located at the eastern edge of the Leduc platform complex, where the platform is up to 200 m thick. Acid-gas injection occurs in the uppermost 18 m of the Leduc aquifer into a reef build-up (Figure 43).

The Leduc Formation in the Puskwaskua area represents three stages of platform development: a) initial platform formation and stabilization, b) a locally rimmed shelf, and c) a “drowning” carbonate ramp with isolated platform edge build-ups (Dix, 1990). The Leduc carbonates are pervasively dolomitized (Figure 44). Generally, clean dolomite along the platform margin grades laterally towards the northwest into argillaceous dolomite and siliciclastics. Basinwards, towards the southeast, as well as vertically, the platform carbonates grade into argillaceous carbonates and shale of the Ireton Formation. The Leduc Formation has undergone a complex diagenetic history. Up to five fluid-flow events related to faulting and fracturing during various tectonic stages of the Peace River Arch resulted in the following main mineral phases: matrix dolomite, various stages of dolomite, calcite and anhydrite cements (Dix, 1993; McKenzie, 1999).

The injection interval in the Leduc Formation is overlain by up to 80 m of shale of the Ireton Formation (Figure 42b) and approximately 40 m dolostone of the Nisku Formation (Figure 43). The Ireton shales thin out towards the northwest, where dolostone of the Nisku Formation directly overlie argillaceous carbonates of the Leduc Formation. The Leduc Formation in the Puskwaskua area was deposited disconformably upon argillaceous carbonates of the Waterways Formation (Beaverhill Lake Group) (Figure 43).

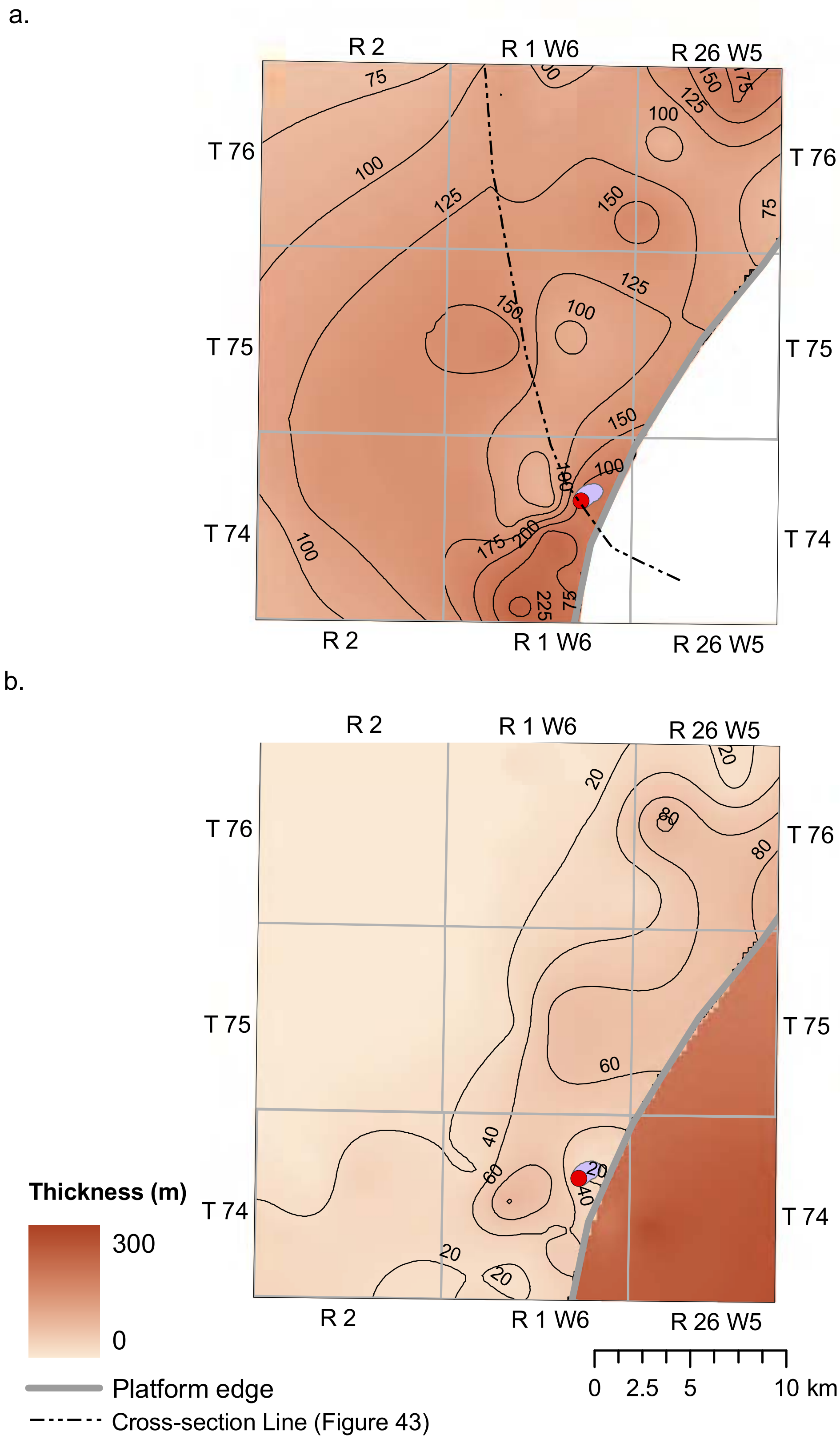


Figure 42. Isopach maps in the Puskwaskua local-scale study area: a) Leduc Formation and b) Ireton Formation. The location of the Puskwaskua injection site and the outline of the Puskwaskua gas pool (purple) are also shown.

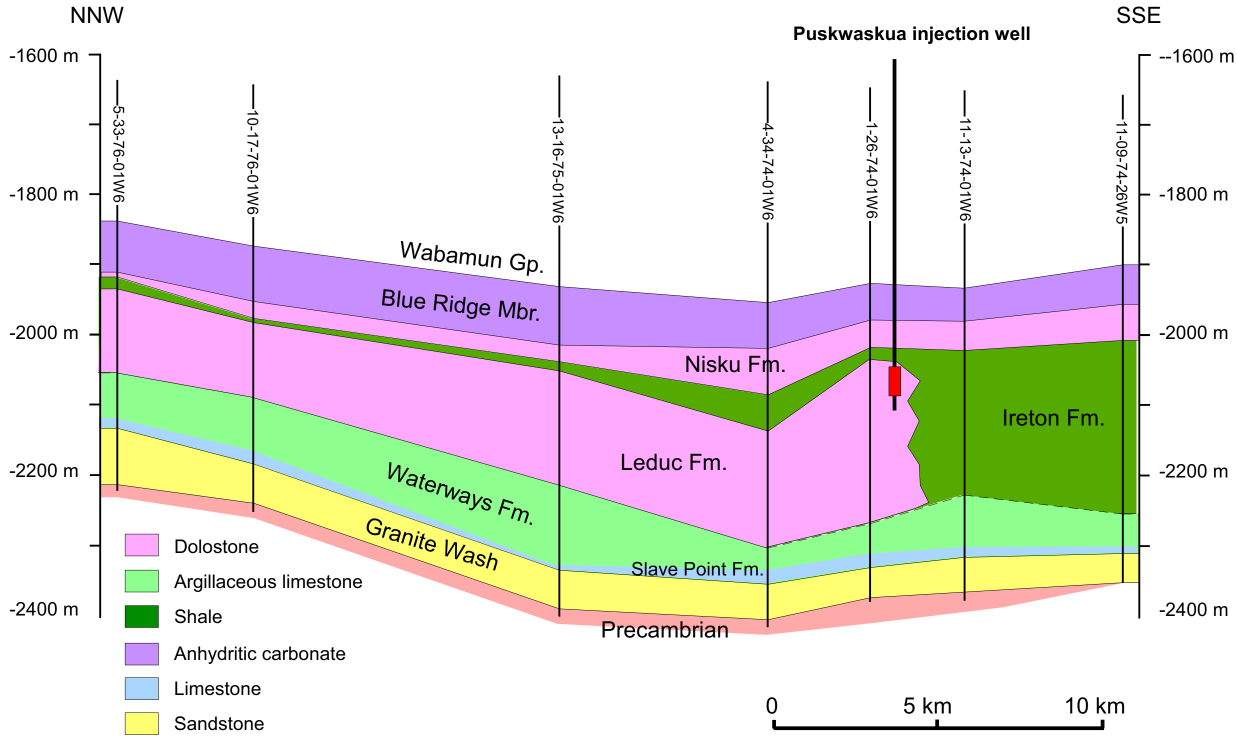


Figure 43. Local-scale cross-section showing the Devonian succession overlying the Precambrian basement through the Puskwaskua area. The injection interval (red bar) is located in the upper part of the Leduc Formation. The location of the line of cross-section is shown in Figure 42.

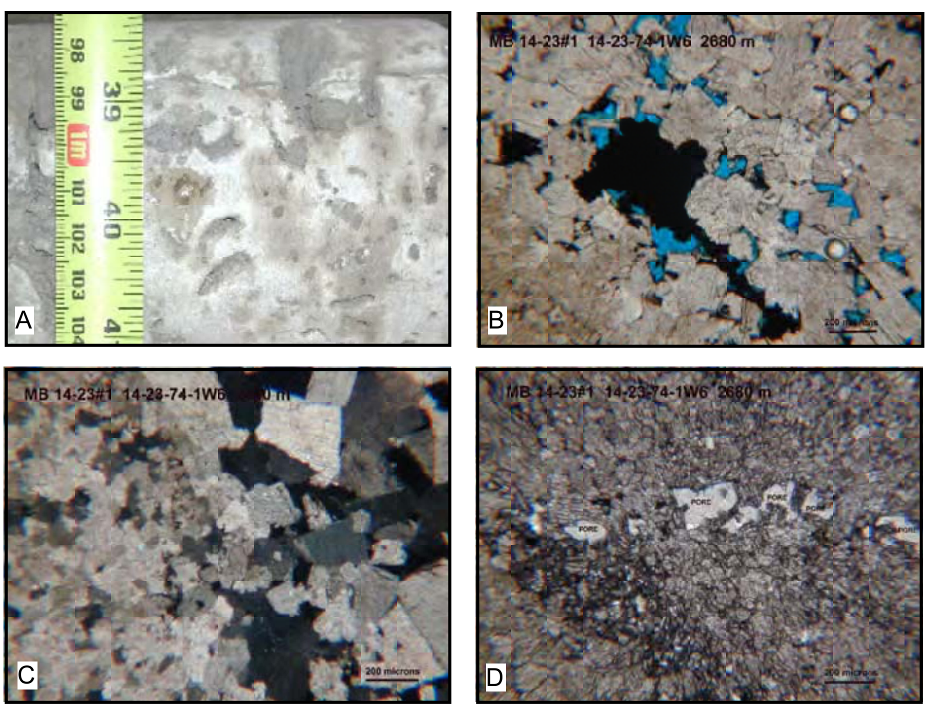


Figure 44. Core and thin section photographs of the Leduc Formation limestone-dolostone sequence at Puskwaskua. Photos A and B show the vuggy and very high porostiy of the reefal dolostones, whereas photos C and D depict the smaller sized moldic micro-porosity in thin section where fossil shells were dissolved and stay open (Photo C) or were later filled with cement (Photo D). Samples were taken from 14-23-74-1W6 at the Puskwaskua injection site.

5.1.2 Hydrogeological Characteristics and Rock Properties

Chemistry of Formation Waters

Fifteen chemical analyses of Leduc Formation water exist in the local-scale study area. The major constituents are chloride (156 g/l), sodium (67 g/l) and calcium (23 g/l) (Table 6). Magnesium, sulphate and bicarbonate are present in minor concentrations (Figure 45a). The salinity decreases slightly from > 280 g/l along the platform margin in the northeast to less than 250 g/l in the south and northwest of the study area (Figure 46a). The average in-situ density of formation water in the Leduc aquifer in the local-scale study area was estimated to be 1159 kg/m^3 using the methods presented in Adams and Bachu (2002).

Table 6. Major ion chemistry of Leduc brines in the Puskwaskua area (concentrations in g/l). * indicates analysis from the acid-gas injection well.

	Na	K	Ca	Mg	Cl	SO_4	HCO_3	TDS
14-22-074-02-W6	66.1	2.6	22.6	2.3	148.0	0.66	0.19	239.7
07-15-074-01-W6	65.9		21.8	2.2	146.1	0.44	0.10	236.4
09-15-074-01-W6	61.4		23.6	3.7	147.0	0.32	0.16	236.1
14-15-074-01-W6	67.1		22.5	3.4	153.0	0.17	0.09	246.2
14-15-074-01-W6	63.1		21.7	3.6	146.0	0.08	0.21	234.6
14-23-074-01-W6*	80.3	3.5	24.3	3.9	178.0	0.29	0.11	286.9
15-26-076-26-W5	81.6	3.2	21.6	4.6	177.0	0.58	0.18	285.5
04-28-074-02-W6	69.5		23.2	2.6	155.4	0.40	0.10	251.1
14-15-075-01-W6	69.3	2.4	22.8	4.4	159.3	0.70	0.06	256.5
13-16-075-01-W6	71.0		24.6	3.5	162.7	0.40	0.13	262.2
13-16-075-01-W6	71.3		22.6	3.3	159.2	0.39	0.22	256.9
13-16-075-01-W6	69.3		23.2	3.3	157.1	0.39	0.25	253.4
02-08-076-26-W5	70.2		23.9	2.9	158.6	0.49	0.26	256.3
08-28-076-01-W6	61.8	2.2	19.4	2.8	137.0	0.76	0.15	221.8
10-23-074-01-W6	68.8		21.2	2.5	150.5	0.43	0.17	243.5
Minimum	57.9	2.2	19.4	2.2	137.0	0.08	0.06	221.8
Maximum	73.6	3.5	24.6	4.6	178.0	0.76	0.26	286.9
Average	67.1	2.8	22.6	3.3	155.7	0.43	0.16	251.1

Pressure Regime

Hydraulic heads, calculated with a reference density of 1100 kg/m^3, decrease from above 580 m in the southwest of the study area to approximately 560 m in the northeast (Figure 46b), indicating northeastward flow sub-parallel to the platform margin. The recorded pressures in the Leduc aquifer are plotted versus elevation in Figure 47 and are compared to pressures in over- and underlying formations. Overall, the data distribution indicates a potential for upward flow from the Granite Wash aquifer (600 m hydraulic head) into the Devonian aquifers (500-600 m hydraulic head and then into the Rundle aquifer

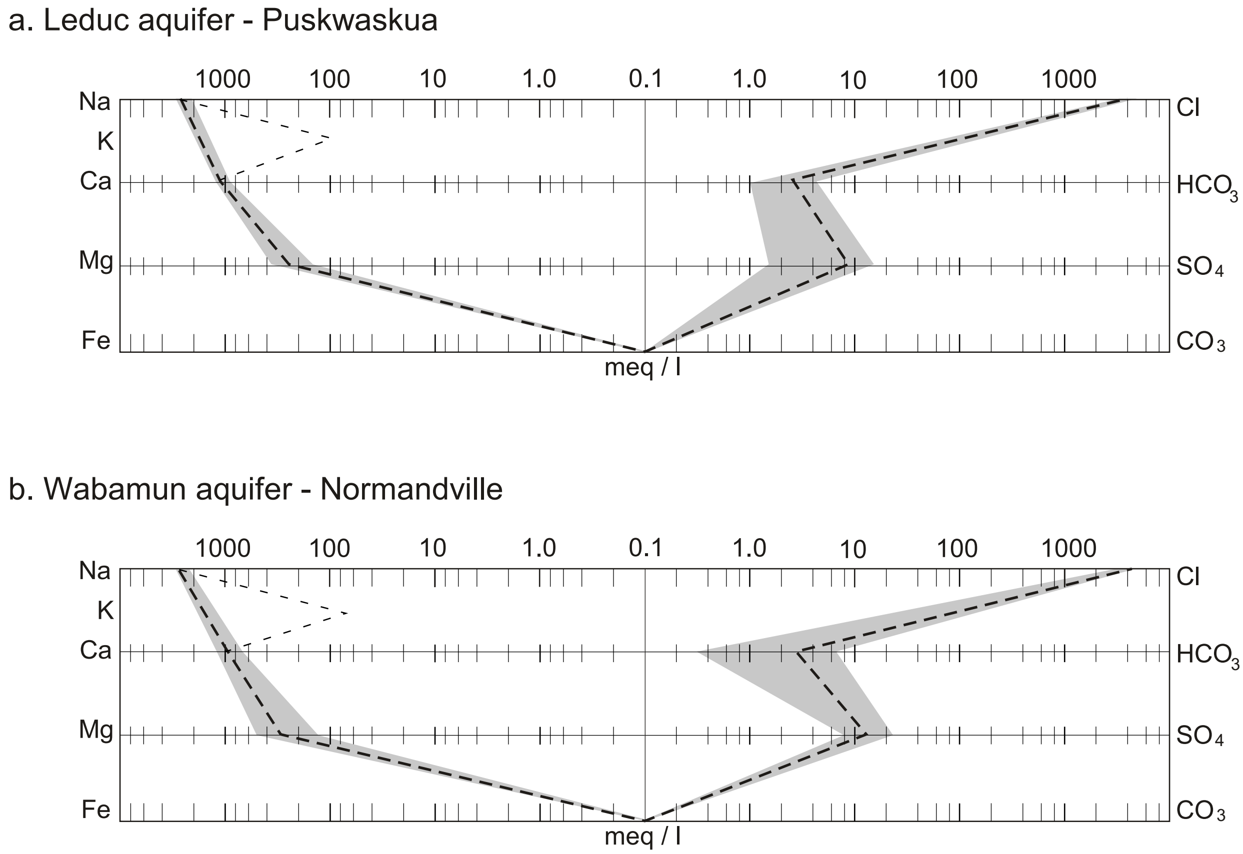


Figure 45. Stiff diagrams of formation waters from the Devonian aquifers in the: a) Puskwaskua area (15 analyses), and b) Normandville area (22 analyses). The grey-shaded area shows the range, the bold dashed line represents the average concentrations in meq/l (milliequilvalents per litre) and the thin dashed line represents the potassium concentration.

(500 m hydraulic head). There is no distinct offset of pressure data measured in the various aquifers, indicating that these aquifers might be in vertical hydraulic communication.

Rock Properties

The well-scale porosity and permeability values for the Leduc and the Ireton formations are shown in Table 7. Also shown are permeability values calculated from drillstem tests that were performed in the Leduc aquifer. Core plug measurements generally are biased toward higher porosity and permeability values. On average, the porosity in the Leduc Formation is 5 %, which is relatively low, considering that the overlying shales of the Ireton Formation have the same value. However, core measurements show good horizontal permeability in the Leduc aquifer, which, on average (180 mD), is more than one magnitude higher than the horizontal permeability in the Ireton aquitard (0.6 mD). The average vertical permeability is significantly lower in both the Leduc Formation (2 mD) and the Ireton Formation (0.1 mD). The average permeability of the Leduc aquifer on the reservoir scale as determined from drillstem tests is 14 mD.

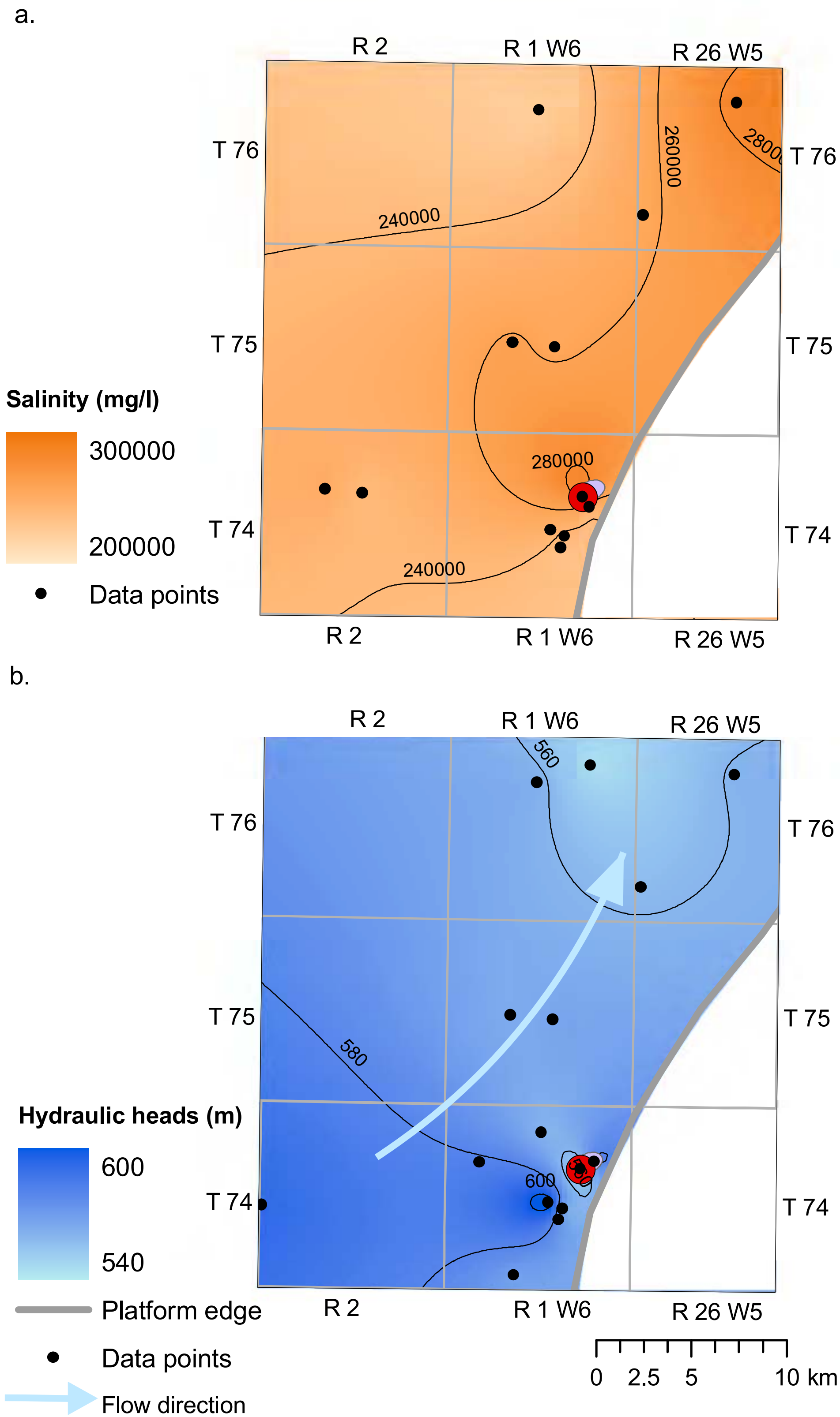


Figure 46. Distribution of a) salinity and b) hydraulic heads in the Leduc aquifer in the Puskwaskua area. The location of the Puskwaskua injection site and the outline of the Puskwaskua gas pool (purple) are also shown.

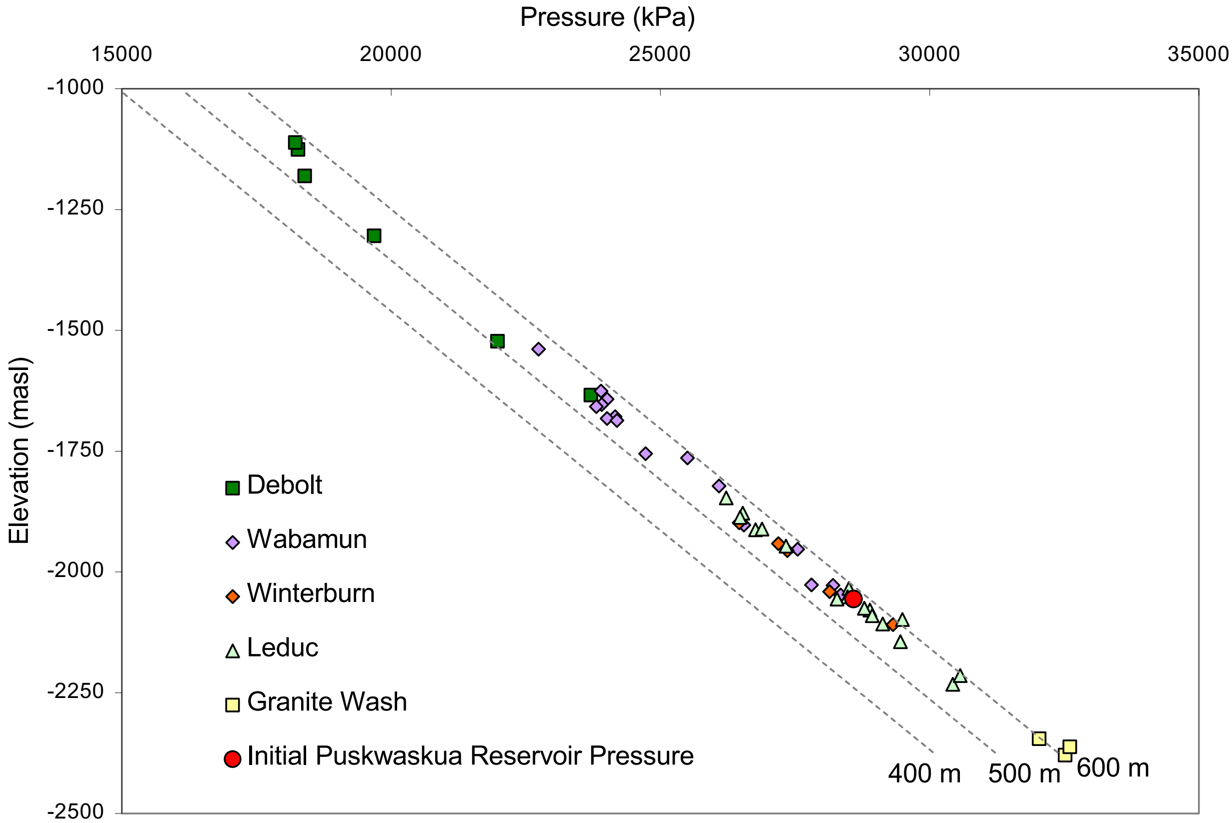


Figure 47. Distribution of pressure versus elevation in the injection strata (Leduc Formation) and adjacent formations in the local-scale study area of the Puskwaskua acid-gas injection operation. The dashed lines delineate pressure-elevation trends with equal hydraulic-head values and the potential for vertical flow may be inferred perpendicular to those lines from high to low values.

Table 7. Well-scale porosity and permeability values obtained from measurements in core plugs from the Leduc (9 wells) and Ireton (2 wells) formations, and permeability values calculated from 7 drillstem test analyses in the Puskwaskua area.

Formation	Porosity (%)			Horiz. Perm. (mD)			Vert. Perm. (mD)			DST Perm. (mD)		
	Min	Max	Avg	Min	Max	Median	Min	Max	Median	Min	Max	Median
Ireton			5			0.6			0.1			
Leduc	2	11	5	18	1600	181	0.6	803	2	1.5	484	14

Flow of Formation Water

Formation water flow in the Leduc aquifer is generally towards the west or southwest in the Puskwaskua area. The flow direction is sub-parallel to the Leduc platform edge. The horizontal hydraulic gradient at the Puskwakua injection site is approximately 1.5 m/km.The high salinity in the Leduc aquifer (220 - 280 g/l) indicates that it is isolated from dilution with meteoric recharge. However, salinity in the overlying Wabamun and Winterburn aquifers is in a similar range as the salinity in the Leduc aquifer and the integrity of intervening aquitards is uncertain. Pressure and corresponding hydraulic-head distributions in these aquifers are in the same range and the intervening Ireton aquitard is thin above the Leduc platform carbonates in the Puskwaskua area, suggesting that there is a possibility of cross-formational hydraulic communication.

5.2 Normandville

The Normandville local-scale study area extends from 55.72°N to 55.99°N and 117.25°W to 117.91°W (Townships 78-80, Ranges 22-25W5) (Figure 12). Two acid-gas injection operations, Normandville and Eaglesham, are located in the study area, both injecting acid gas into depleted oil reservoirs that produced from the Wabamun Group.

5.2.1 Geology

In the local-scale study area, the thickness of the entire Wabamun Group ranges from 220 m to 280 m (Figure 48a). The Wabamun Group can be subdivided from bottom to top into four members: Dixonville, Whitelaw, Normandville, and Cardinal (i.e., Halbertsma, 1959). The lithofacies distribution in the various members is shown along a southwest-northeast trending cross-section (Figure 49). The lowermost unit, the Dixonville Member is completely dolomitized, except for some pelletoidal limestone in the southwestern corner of the study area. The Whitelaw Member is dolomitized in the north-central part of the study area, along the Tangent Fault, whereas the other areas consist of mudstone or bioturbated limestone. In comparison, in the Normandville Member the dolomitized areas extend farther towards the south, while the remainder of this succession is formed by bioturbated and pelletoidal limestone (Figure 50). The Cardinal Member at the top of the Wabamun Group mainly consists of bioturbated limestone and pelletoidal grainstone, and only an area in the north-central part of the area is continuously dolomitized. Still, isolated dolomitized mud mounds, 200-400 m in diameter, are present throughout the Cardinal Member.

Initially, the Wabamun Group carbonates were tight. Only fracturing and dolomitization after deposition and lithification created increased porosity and permeability of reservoir quality (Saller and Yaremko, 1994; Figure 50). There are two different interpretations on the timing and origin of dolomitizing fluids. According to Workum (1991), dolomitization occurred shortly after deposition at the end of the Devonian, by the circulation of a mixture of seawater and meteoric water through a karstified limestone. On the other hand, Packard and Pellegrin (1989) suggest that the dolomitization of limestone was driven by thermal advection of hydrothermal fluids and mixing with seawater during the Mississippian. The concentration of dolomite along the Tangent fault, which was initiated during the Mississippian, indicates this fault acted as a pathway for dolomitizing fluids in the study area.

The injection targets at Normandville and Eaglesham are isolated dolomitized mound-like structures (Saller and Yaremko, 1994) in the Cardinal Member at the top of the Wabamun Group (Figure 49). The Wabamun Group is overlain by 2 to 15 m of shales of the Exshaw Formation (Figure 48b) and up to 10 m of shale in the Lower Banff Formation. Locally tight anhydritic carbonates of the Winterburn Group form the bottom seal in the Normandville area.

5.2.2 Hydrogeological Characteristics and Rock Properties

Chemistry of Formation Waters

The major constituents of Wabamun formation water in the Normandville area as determined from 22 analyses are chloride (147 g/l), sodium (66 g/l) and calcium (20 g/l) (Table 8). Magnesium, sulphate and

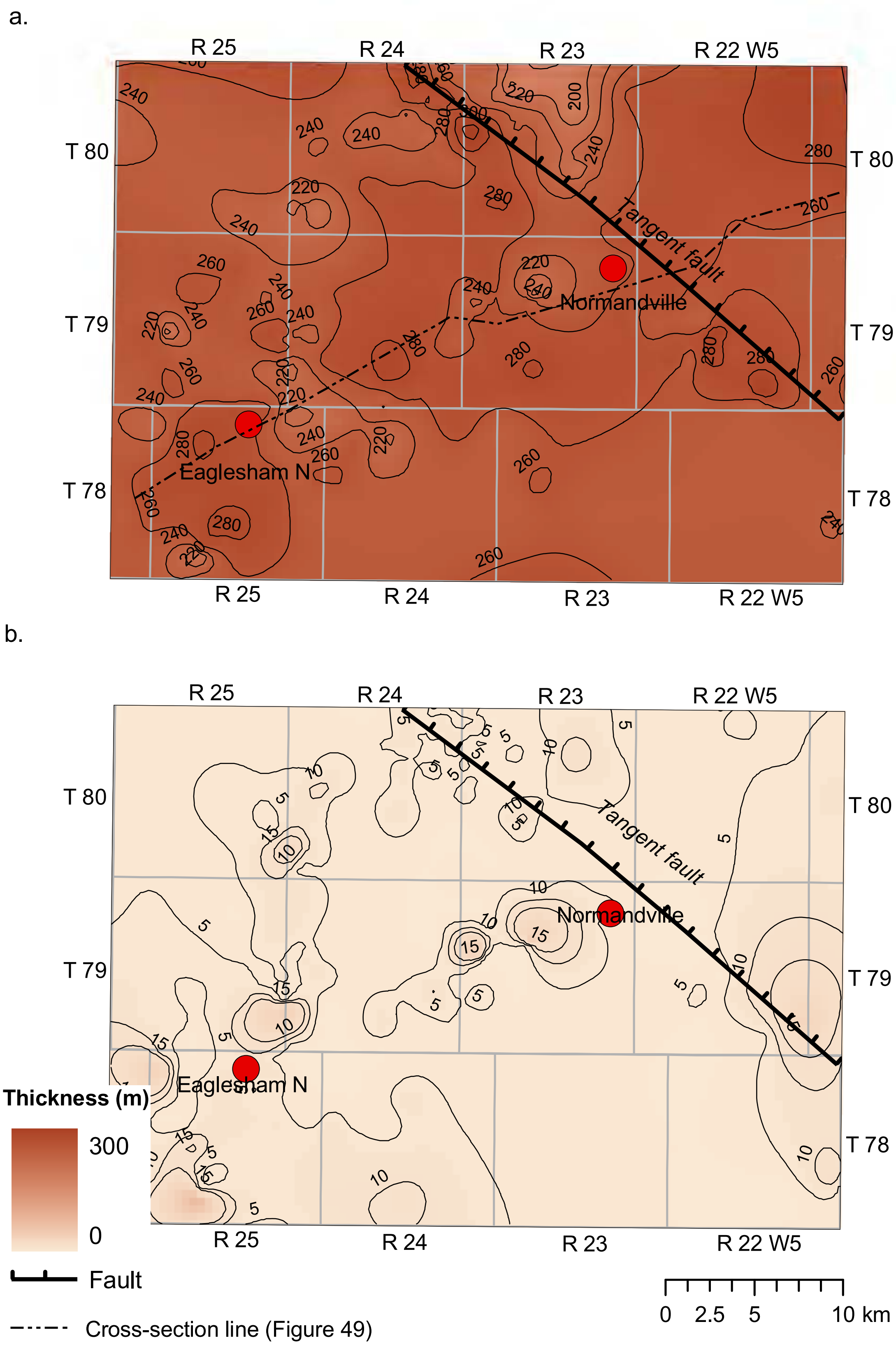


Figure 48. Isopach maps in the Normandville local-scale study area: a) Wabamun Group and b) Exshaw Formation. The locations of the Normandville and Eaglesham injection sites are also shown.

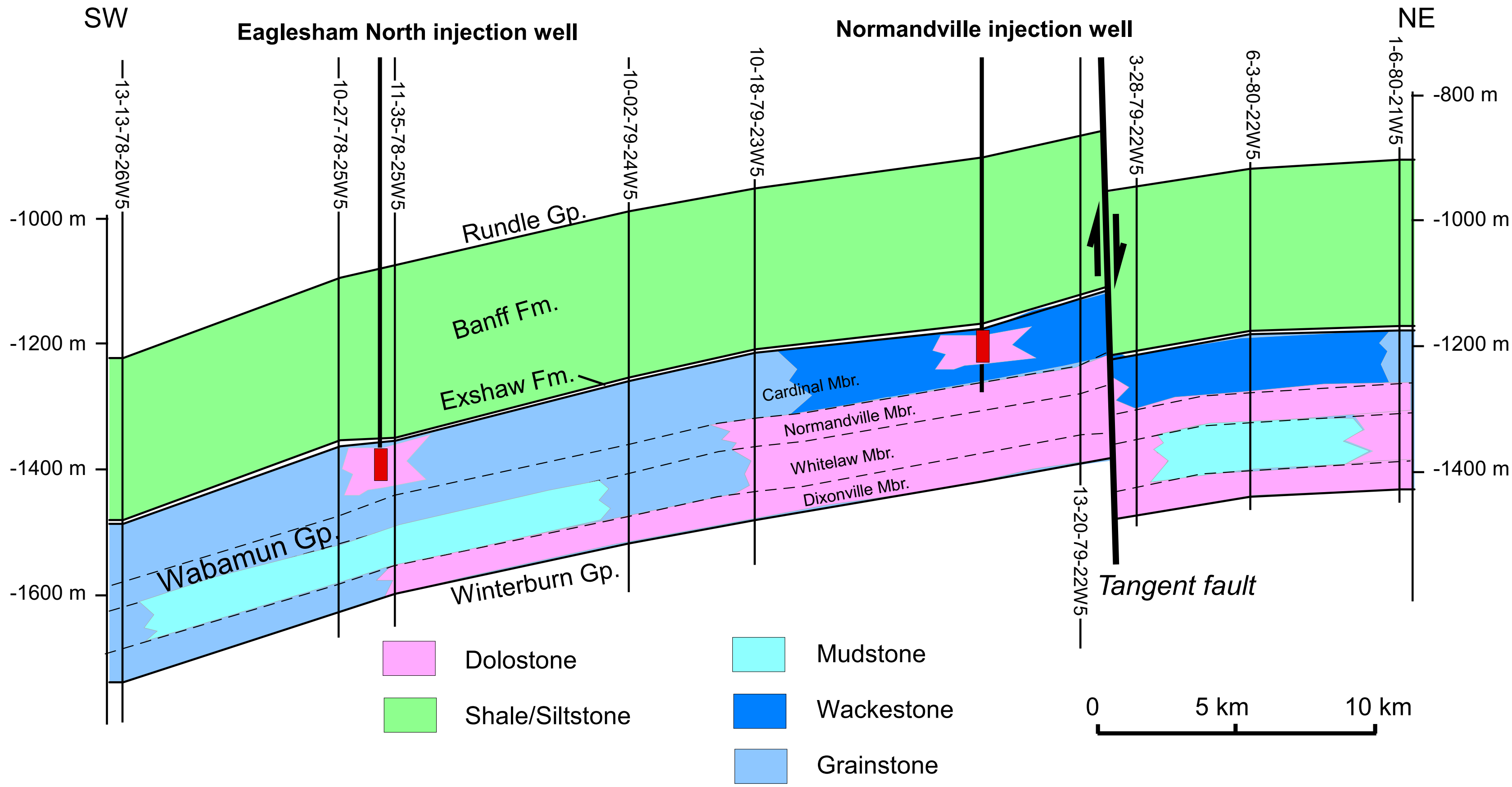


Figure 49. Local-scale structural cross-section showing the lithofacies distribution from the Wabamun Group to the Banff Formation in the Normandville area. The injection interval (red bar) is located in the Cardinal Member, in the upper part of the Wabamun Group. The location of the line of cross-section is shown in Figure 48.

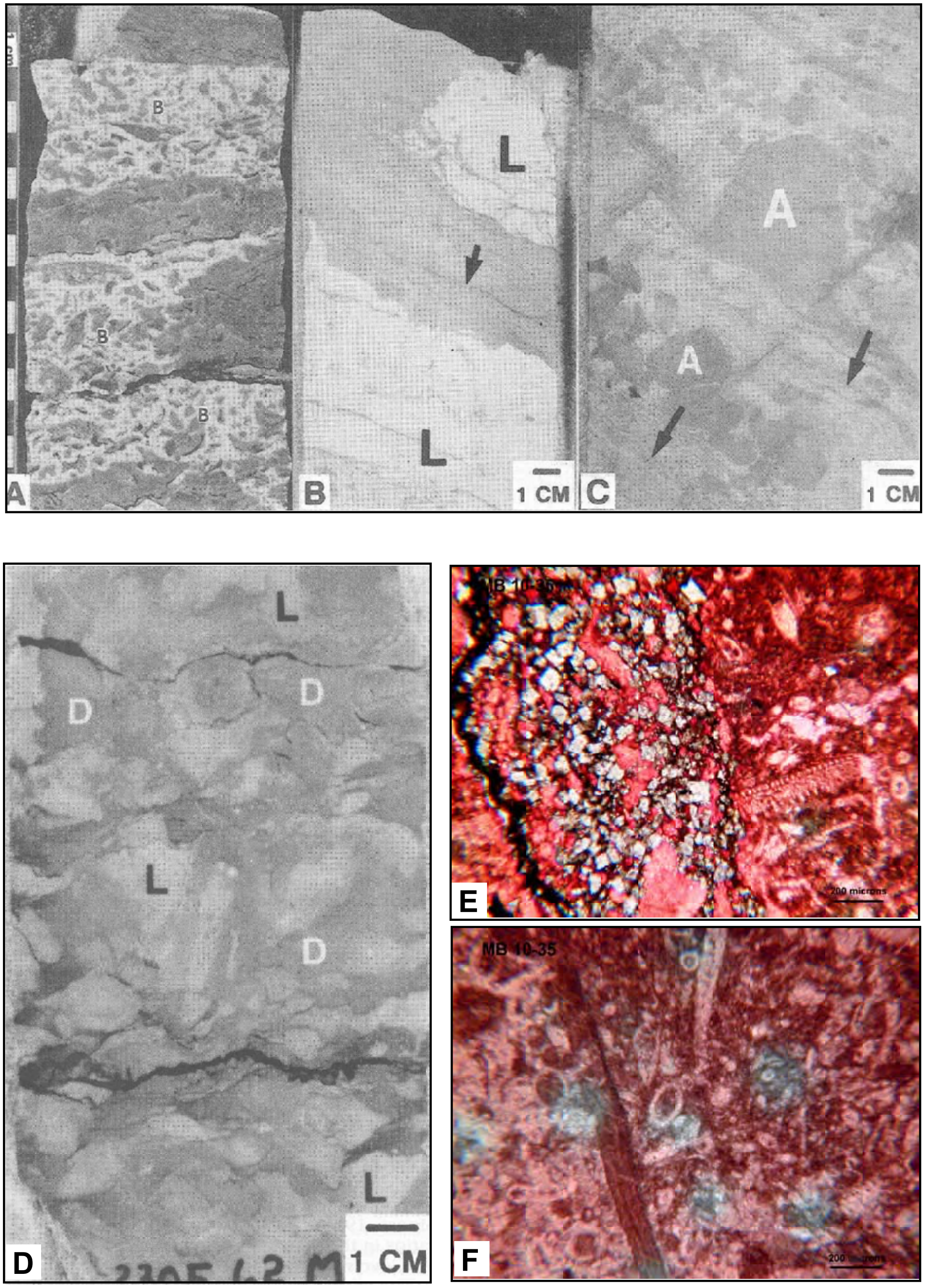


Figure 50. Figures A to D show core photographs of fossiliferous limestone (L) with abundant dolomitized mudstone burrow fills (D) of the Wabamun Group. The limestone areas contain scattered dolomite rhombs best seen in the thin section photograph E. F depicts the abundant fossils in the limestone. Samples for thin sections were taken from the 10-35-078-25-W-5 well. Photos A to D are from Saller and Yaremko, 1994.

bicarbonate are present in minor concentrations (Figure 45b). In the Normandville area, the salinity of formation water ranges between 200 g/l and 280 g/l, without any obvious distributional trend (Figure 51a). Salinity values in the Normandville area are relatively high compared to the regional salinity distribution in the Wabamun aquifer (Figure 32). The average in-situ density of formation water in the local-scale study area was estimated to be 1156 kg/m^3 using the methods presented in Adams and Bachu (2002).

Table 8. Major ion chemistry of Wabamun brines in the Normandville area (concentrations in g/l).

	Na	K	Ca	Mg	Cl	SO_4	HCO_3	TDS
03-08-079-25-W-5	64.1	2.7	21.0	4.2	148.0	0.49	0.13	237.9
01-16-079-22-W-5	63.0		21.3	3.0	143.0	0.65	0.19	231.0
01-16-079-22-W-5	66.6		23.4	3.5	154.0	0.41	0.14	248.0
10-16-079-22-W-5	65.2		21.7	3.7	149.2	0.39	0.13	240.2
10-16-079-22-W-5	71.2		20.2	3.7	156.0	0.50	0.18	251.8
04-12-079-23-W-5	54.5		17.2	3.0	122.7	0.53	0.24	198.1
14-23-079-24-W-5	62.3	1.6	20.5	4.2	143.8	0.77	0.28	231.7
06-11-080-23-W-5	65.6		20.0	2.7	144.0	0.48	0.17	232.9
02-31-080-23-W-5	69.3	2.6	19.7	4.6	154.6	0.47	0.02	248.6
07-35-078-24-W-5	60.7		20.8	3.8	141.0	0.51	0.41	227.0
16-06-080-24-W-5	61.8	1.8	17.9	3.8	137.4	0.79	0.08	221.8
11-02-080-25-W-5	67.9	1.2	15.1	3.9	142.0	0.61	0.14	229.5
06-19-078-24-W-5	57.3	4.9	21.6	5.8	143.0	0.47	0.33	228.3
09-13-079-25-W-5	66.9	2.0	15.2	5.9	147.0	0.58	0.13	235.8
02-16-079-25-W-5	75.5	2.1	18.8	1.7	154.0	0.77	0.12	250.8
08-13-080-24-W-5	59.5	2.0	17.6	2.2	129.0	0.42	0.14	208.8
05-01-080-23-W-5	79.7	1.1	20.8	3.4	169.0	0.61	0.21	273.6
13-06-080-24-W-5	75.9	2.7	24.8	4.4	173.0	0.70	0.31	278.9
04-26-080-24-W-5	52.3	1.6	20.0	6.1	133.0	0.97	0.18	212.5
11-19-080-23-W-5	74.3	2.4	22.8	4.4	167.0	0.70	0.23	269.3
15-24-080-24-W-5	70.1	2.0	16.6	2.1	142.5	1.14	0.42	232.7
08-23-080-24-W-5	67.8	2.0	18.8	4.6	150.8	0.53	0.18	242.6
Minimum	52.3	1.1	15.1	1.7	122.7	0.39	0.02	198.1
Maximum	79.7	4.9	24.8	6.1	173.0	1.14	0.42	278.9
Average	66.0	2.2	19.8	3.9	147.5	0.61	0.20	237.8

Pressure Regime

Hydraulic heads in the Wabamun aquifer, calculated with a reference density of 1100 kg/m^3, decrease slightly from above 520 m in the southwest and east to less than 500 m in the center and in the east of the study area, which corresponds to a low hydraulic gradient (Figure 51b). The hydraulic head contours suggest that the flow of formation water, although subtle, is generally towards the east and northeast,

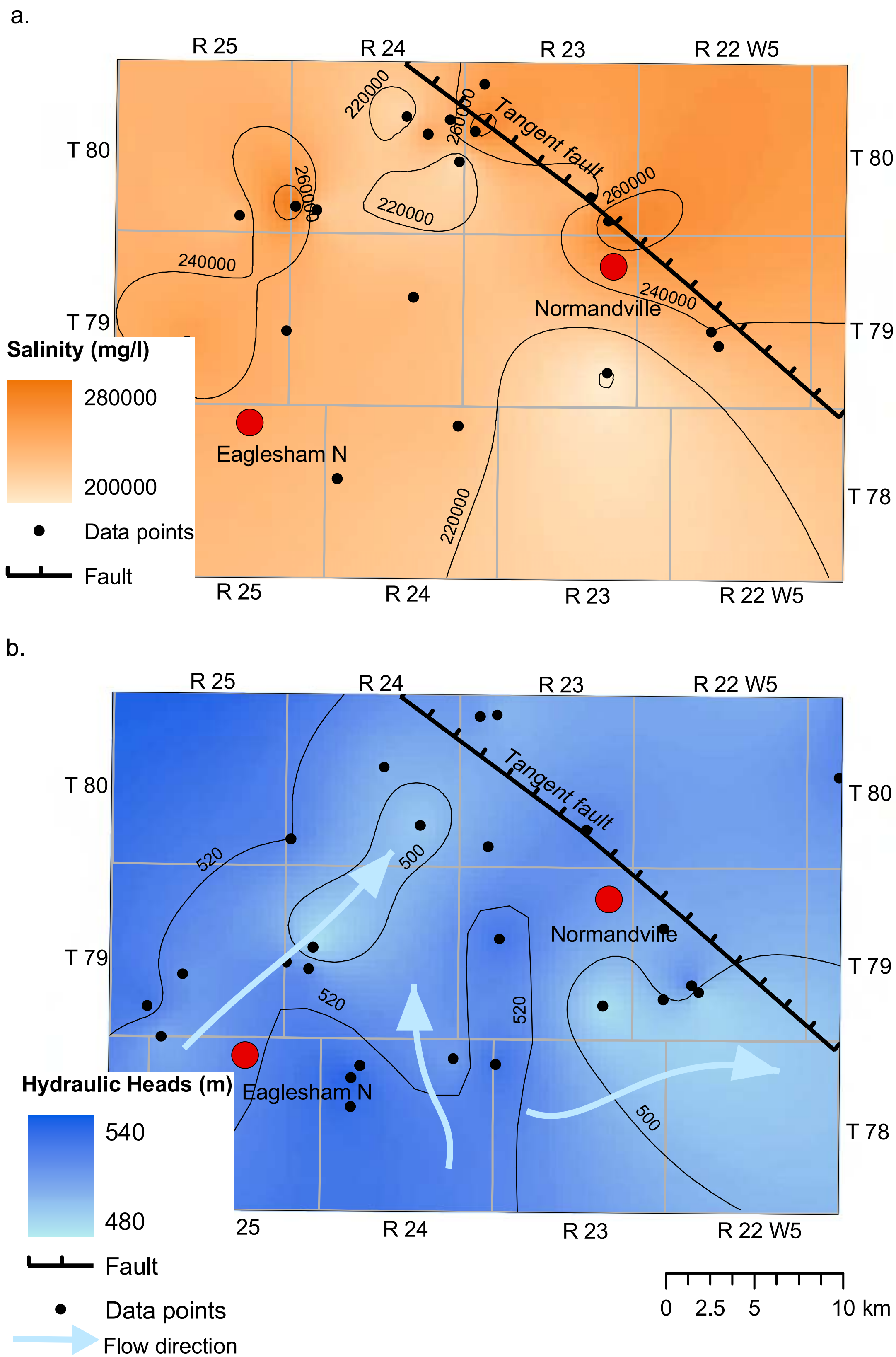


Figure 51. Distribution of a) salinity and b) hydraulic heads in the Wabamun aquifer in the Normandville area. The locations of the Normandville and Eaglesham injection sites area also shown.

following the regional flow pattern in the Wabamun aquifer (Figure 37b). The distribution of pressure versus elevation (Figure 52) shows that data from the Wabamun and Winterburn aquifers plot along a similar trend, suggesting that the as “tight” identified anhydritic carbonates at the top of the Winterburn Group do not form a contiguous barrier to flow between the two aquifers.On the other hand, pressure data in the overlying Banff Formation are equivalent to hydraulic-head values between 400 to 450 m, suggesting that the intervening Exshaw-Lower Banff aquitard is an effective barrier to vertical flow.

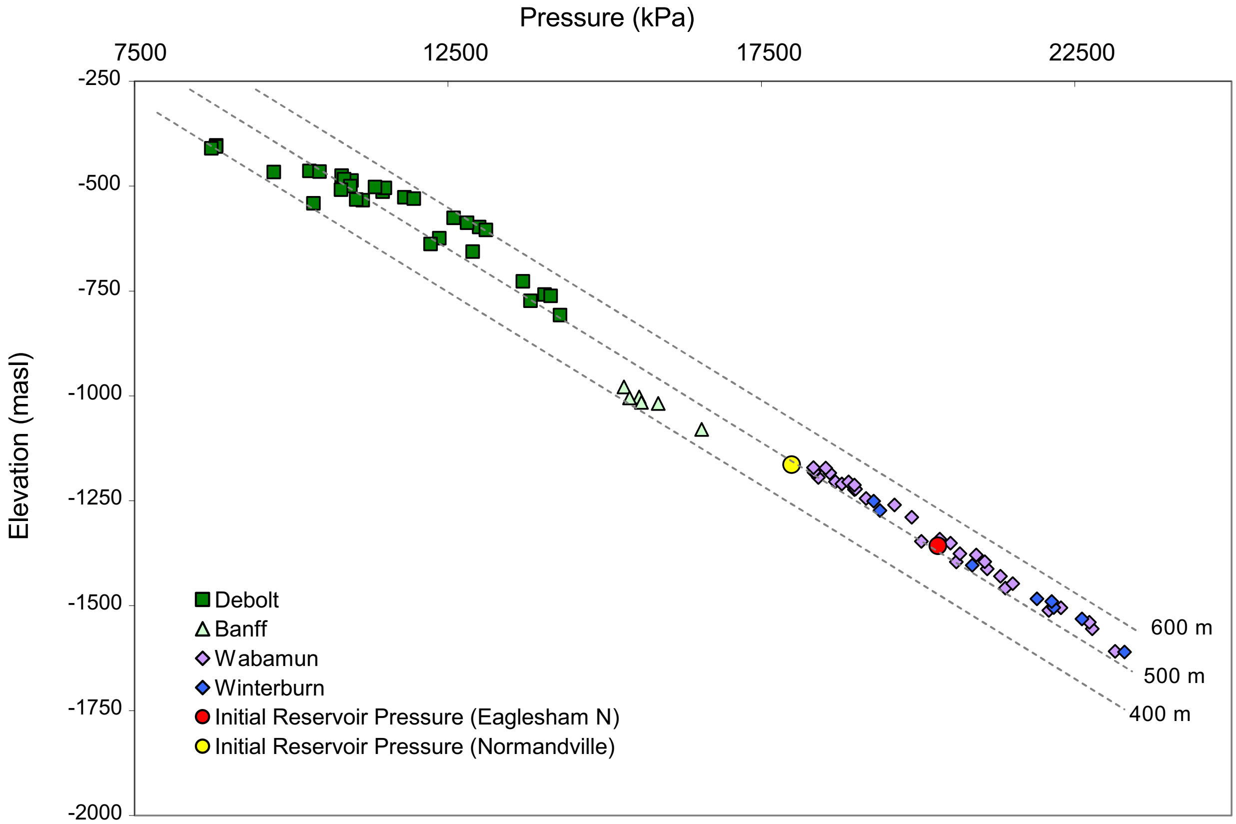


Figure 52. Distribution of pressure versus elevation in the injection strata (Wabamun Group) and adjacent formations in the Normandville area. The dashed lines delineate pressure-elevation trends with equal hydraulic-head values and the potential for vertical flow may be inferred perpendicular to those lines from high to low values.

Rock Properties

The average porosity (2.1%), the median horizontal permeability (0.7 mD), and the median vertical permeability (0.3 mD) in Table 9 suggest that the Wabamun carbonates form a relatively inefficient aquifer with respect to fluid flow in the Normandville area. However, local higher-permeability zone exists as indicated by permeability values calculated from drillstem tests in the Wabamun aquifer, which range from 0.12 to 412 mD with a median value of 11 mD. The overall low porosity and permeability values for the Exshaw Formation make it an effective aquitard.

Table 9. Well-scale porosity and permeability values obtained from measurements in core plugs from the Wabamun (107 wells) and Exshaw (18 wells) formations, and permeability values calculated from 30 drillstem test analyses in the Normandville area.

	Porosity (%)			Horiz. Perm. (mD)			Vert. Perm. (mD)			DST Perm. (mD)		
Formation	Min	Max	Avg	Min	Max	Median	Min	Max	Median	Min	Max	Median
Wabamun	0.5	7	2.1	0.01	862	0.7	0.001	481	0.3	0.12	412	11
Exshaw	1	5	1.9	0.01	40	0.02	0.01	8	0.1			

Flow of Formation Water

The lithology distribution in the Wabamun Group is very heterogeneous, varying form low-permeability limestone to high-permeability dolostone. Consequently, flow of the high-salinity formation water is channelled preferentially along the dolomitized portions of the Wabamun Group towards the northeast and east in the western and eastern half of the Normandville area, respectively. The hydraulic gradient is approximately 1.5 m/km. Similar ranges in pressures and salinity in the Wabamun and underlying Winterburn aquifer confirm the regional interpretation of a contiguous Wabamun-Winterburn aquifer. In contrast, the interpretation of pressure and salinity data shows that the Exshaw-Lower Banff aquitard forms an effective barrier to cross-formational flow between the Wabamun and Banff aquifers.

5.3 Rycoft

The Rycroft local-scale study area extends from 55.55°N to 55.81°N and 118.15°W to 118.62°W (Townships 76-78, Ranges 2-4W6) (Figure 12). Injection takes place in the Kiskatinaw Formation, a water-wet, non-producing unit, which forms the lower part of the Belloy-Stoddart aquifer. At Rycroft, gas is produced from the underlying Debolt Formation, which is part of the Mississippian Rundle Group.

5.3.1 Geology

Structurally, the Rycroft area lies in the Saddle River Low south of the Dunvegan Horst (Figure 15). The Kiskatinaw Formation in the Rycroft area was deposited in a fluvial/estuarine to shallow marine sequence, dominantly consisting of sandstones with interbedded shales (Barclay *et al*., 1990). The formation decreases in thickness from 120 m in the west to 0 m in the northeast of the local-scale study area, where it pinches out against the southeastern extension of the Dunvegan Horst (Figures 53a and 54). The Kiskatinaw Formation can be subdivided in to a basal sandstone unit, a middle shale unit and an upper interbedded sandstone-shale unit (Barclay *et al*., 1990).

Acid-gas injection occurs into the 40 m thick basal sandstone unit at the southwest flank of the structural high, where the entire Kiskatinaw Formation is 70 m thick (Figure 53a). Figure 55 shows core and thin-section photographs of the Kiskatinaw sandstone. The injection interval is overlain locally by 9 m thick shales and approximately 20 m of interbedded sandstone and shales in the upper part of the Kiskatinaw. Overlying the Kiskatinaw Formation are tight carbonates of the Taylor Flat Formation that range in thickness between 10 and 60 m (Figure 54b).On the average of 30 m thick shales of the Golata Formation provide the bottom seal of the Kiskatinaw basal sandstone unit. No offset along the Rycroft Fault is apparent from stratigraphic correlations along the cross-section in Figure 54.

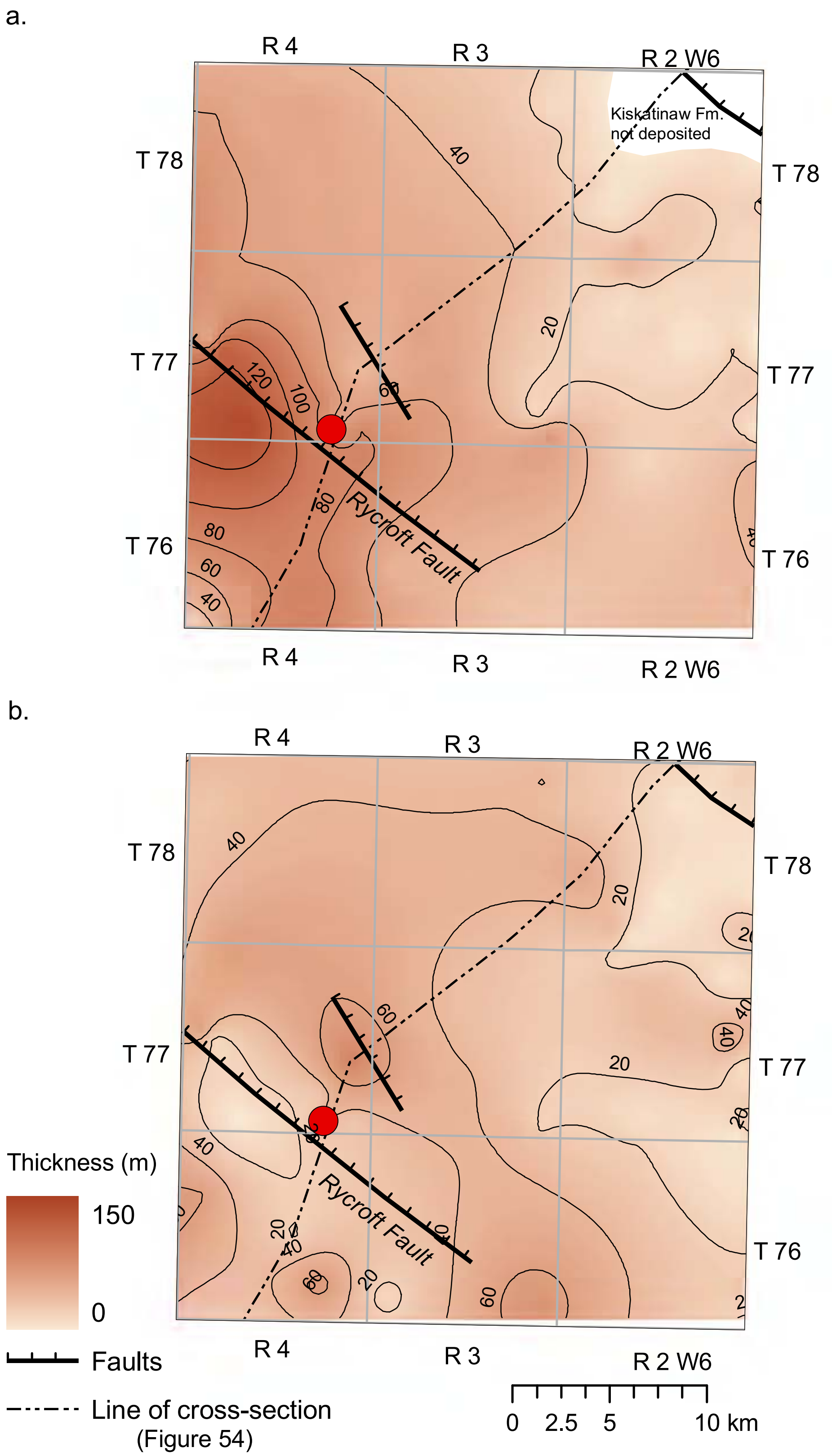


Figure 53. Isopach maps in the Rycroft local-scale study area: a) Kiskatinaw Formation and b) Taylor Flat Formation. The location of the Rycroft injection site is also shown.

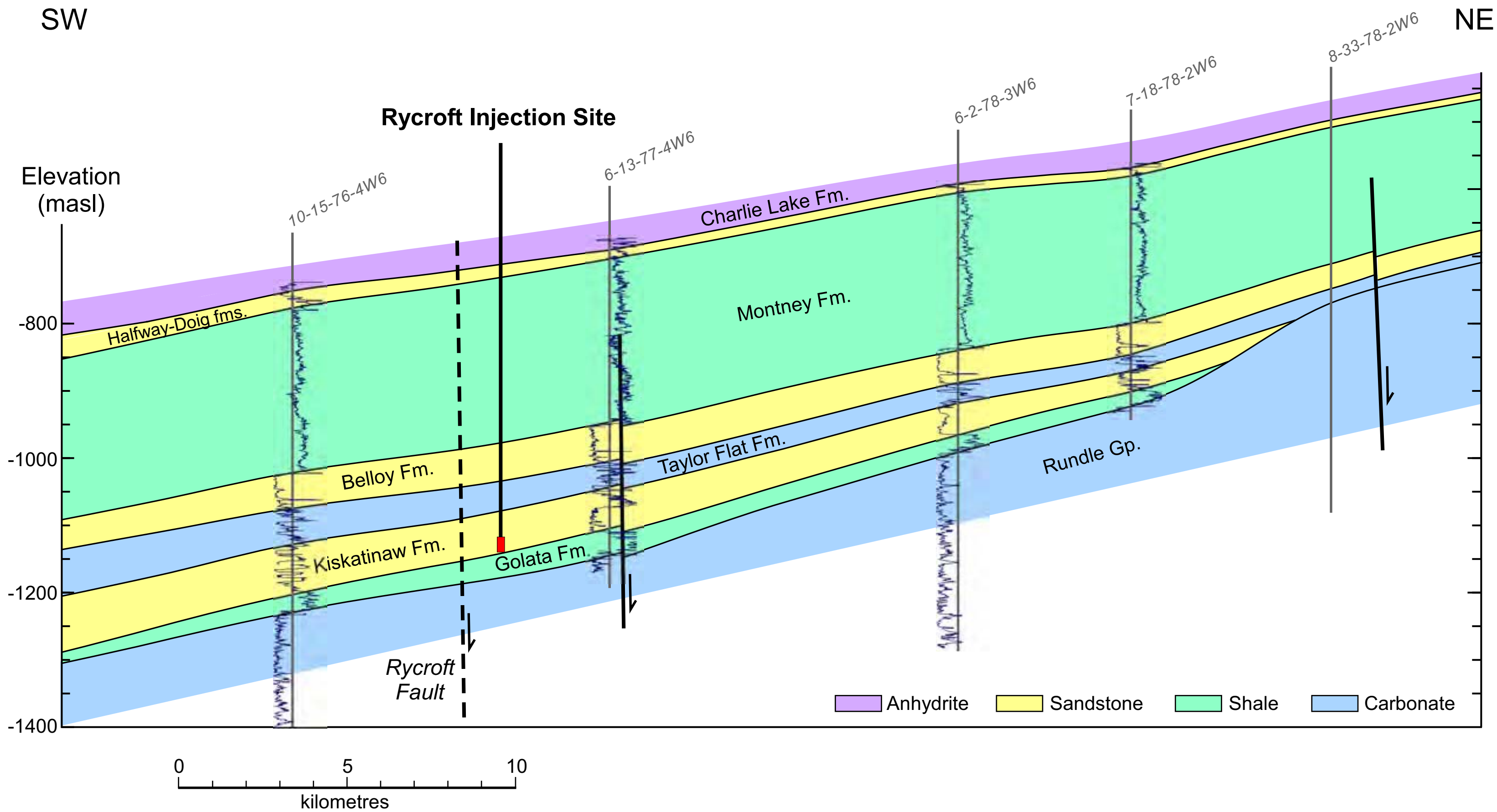


Figure 54. Local-scale structural cross-section showing the general lithofacies distribution from the top of the Rundle Group to the base of the Charlie Lake Formation in the Rycroft area. The injection interval (red bar) is located in the basal sandstone unit of the Kiskatinaw Formation. The gamma-ray logs show the intraformational lithofacies heterogeneity, particularly in the Taylor Flat and Kiskatinaw formations. The location of the line of cross-section is shown in Figure 53.

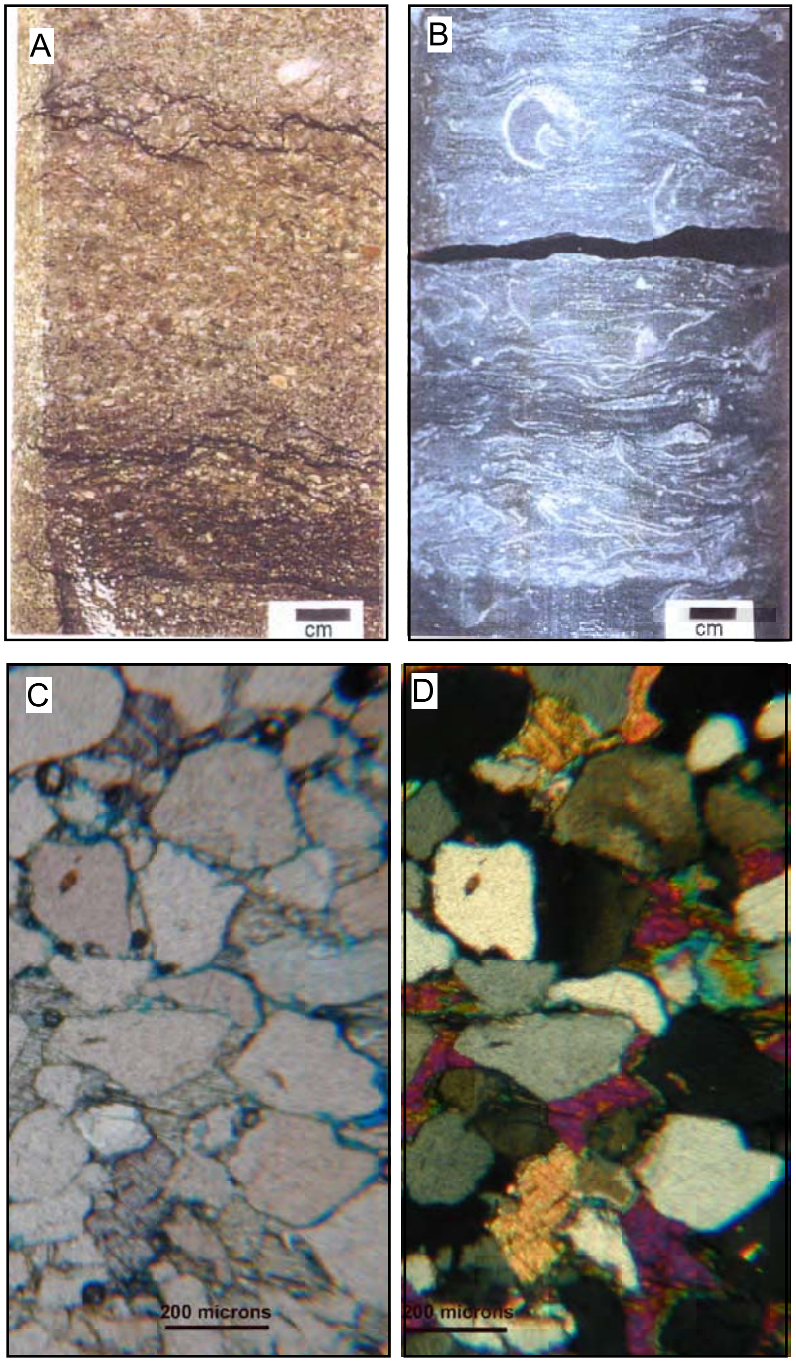


Figure 55. Figures A to B show core photographs of sandy, bioclastic grainstones in the Kiskatinaw Formation (from Barclay, 2000). Figure C and D are thin-section photographs of grainy sandstone with blue-stained porostiy from the Kiskatinaw Formation in the Rycroft area (10-21-77-2W6).

5.3.2 Hydrogeological Characteristics and Rock Properties

Relatively few hydrogeological data exist for the Kiskatinaw Formation in the Rycroft area, because the petroleum industry has focused mainly on hydrocarbon occurrences in the overlying and underlying stratigraphic successions. However, the regional hydrogeological analysis indicated a weak or non-existing hydraulic separation of the Belloy and Kiskatinaw aquifers, suggesting that the intervening Taylor Flat aquitard is not contiguous and only locally forms an effective barrier to flow. In the following, the Belloy and Kiskatinaw formations will be considered as a combined aquifer.

Chemistry of Formation Waters

The major constituents of Belloy-Stoddart formation water as determined from 6 analyses are chloride (87 g/l) and sodium (52 g/l), making up 95% of the total dissolved solids (Table 10). Magnesium, calcium, sulphate and bicarbonate are present in minor concentrations (Figure 56a). In the Rycroft area, formation water chemistry is relatively invariable, salinity slightly decreasing from approximately 160 g/l in the southwest and center to less than 140 g/l in the north- and southeast (Figure 57a). The average in-situ density of formation water in the Permo-Carboniferous aquifer in the local-scale study area was estimated to be 1093 kg/m^3 using the methods presented in Adams and Bachu (2002).

Table 10. Major ion chemistry of brines from the Belloy and Kiskatinaw formations in the Rycoft area (concentrations in g/l). * indicates analysis from the acid-gas injection well.

	Na	K	Ca	Mg	Cl	SO_4	HCO_3	TDS
Belloy								
11-01-076-02-W-6	48.3		2.8	0.9	80.0	2.00	0.79	134.3
06-35-077-02-W-6	52.1	0.7	3.1	0.7	84.4	4.64	0.24	145.1
06-35-077-02-W-6	48.3	1.8	5.4	0.6	83.9	2.69	0.02	140.9
Kiskatinaw								
07-29-077-02-W-6	55.8		5.5	1.1	97.6	1.97	0.08	162.1
02-11-076-04-W-6	50.4	0.8	3.5	1.0	85.0	1.97	0.31	141.9
07-02-077-04-W-6*	60.1	0.9	4.3	1.1	93.7	1.60	0.21	162.0
Minimum	48.3	0.7	2.8	0.6	80.0	1.60	0.02	134.3
Maximum	60.1	1.8	5.5	1.1	97.6	4.64	0.79	162.1
Average	52.5	1.1	4.1	0.9	87.4	2.48	0.27	147.7

Pressure Regime

Hydraulic heads, calculated with a reference density of 1110 kg/m^3, only vary slightly between 385 m in the southwest and northeast and 415 m in the center of the study area (Figure 57b). The contour pattern suggests divergent flow of formation water towards the northeast and southwest, respectively. However, differences in hydraulic-head values are too subtle for a definite interpretation. Regional-scale flow of formation water in the Belloy-Stoddart aquifer is towards the northeast.

Plotting pressure values versus elevation (Figure 58) shows that data from the Belloy and Kiskatinaw formations plot along a trend (400 m equivalent hydraulic head) distinctly lower than data in the overlying Triassic aquifers (450-500 m equivalent hydraulic head) and in the underlying Rundle aquifer (450 m equivalent hydraulic head).This offset in pressure trends suggests that the intervening shales of the Montney and Golata formations form respectively effective aquitards above and below the Belloy-Stoddart aquifer. The respective potential for vertical flow is downward from the Halfway-Doig aquifer and upward from the Rundle aquifer into the Belloy-Stoddart aquifer.

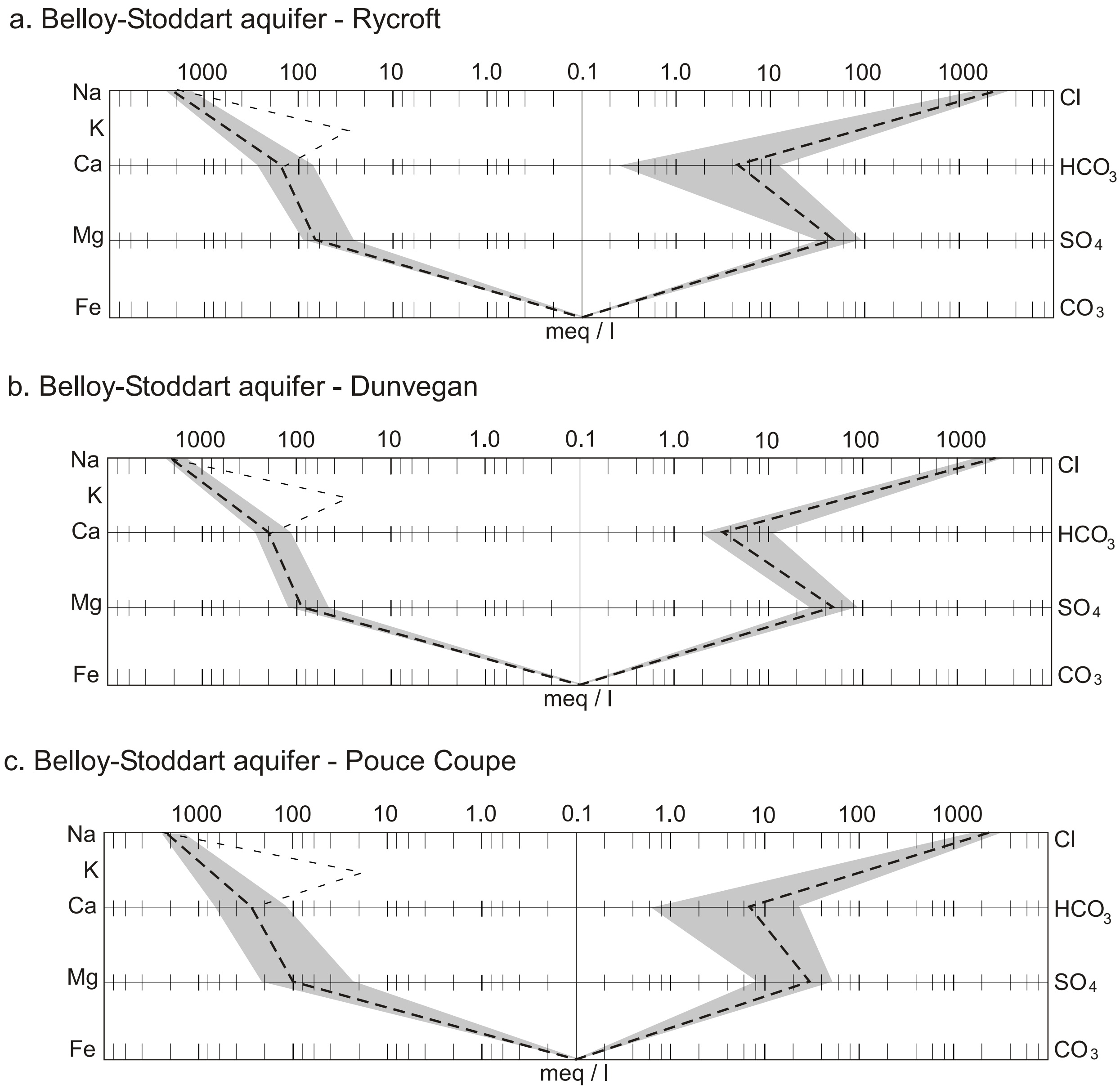


Figure 56. Stiff diagrams of formation waters from the Belloy-Stoddart aquifer in the: a) Rycroft area (76 analyses), Dunvegan area (76 analyses), and Pouce Coupe area (76 analyses). The grey-shaded area shows the range, the bold dashed line represents the average concentrations in meq/l (milliequilvalents per litre) and the thin dashed line represents the potassium concentration.

Rock Properties

The average of well-scale porosity and permeability values for the injection horizon, the Kiskatinaw Formation, and for the overlying Belloy Formation are shown in Table 11. Also shown are permeability values calculated from drillstem tests that were performed in the Belloy-Stoddart aquifer. The average values of porosity (9.5 %), horizontal permeability (17.5 mD) and vertical permeability (2.7 mD) in the injection horizon, the Kiskatinaw Formation, are noticeably higher than respective values in the overlying Belloy Formation. However, median permeability values calculated from DST analyses in the respective

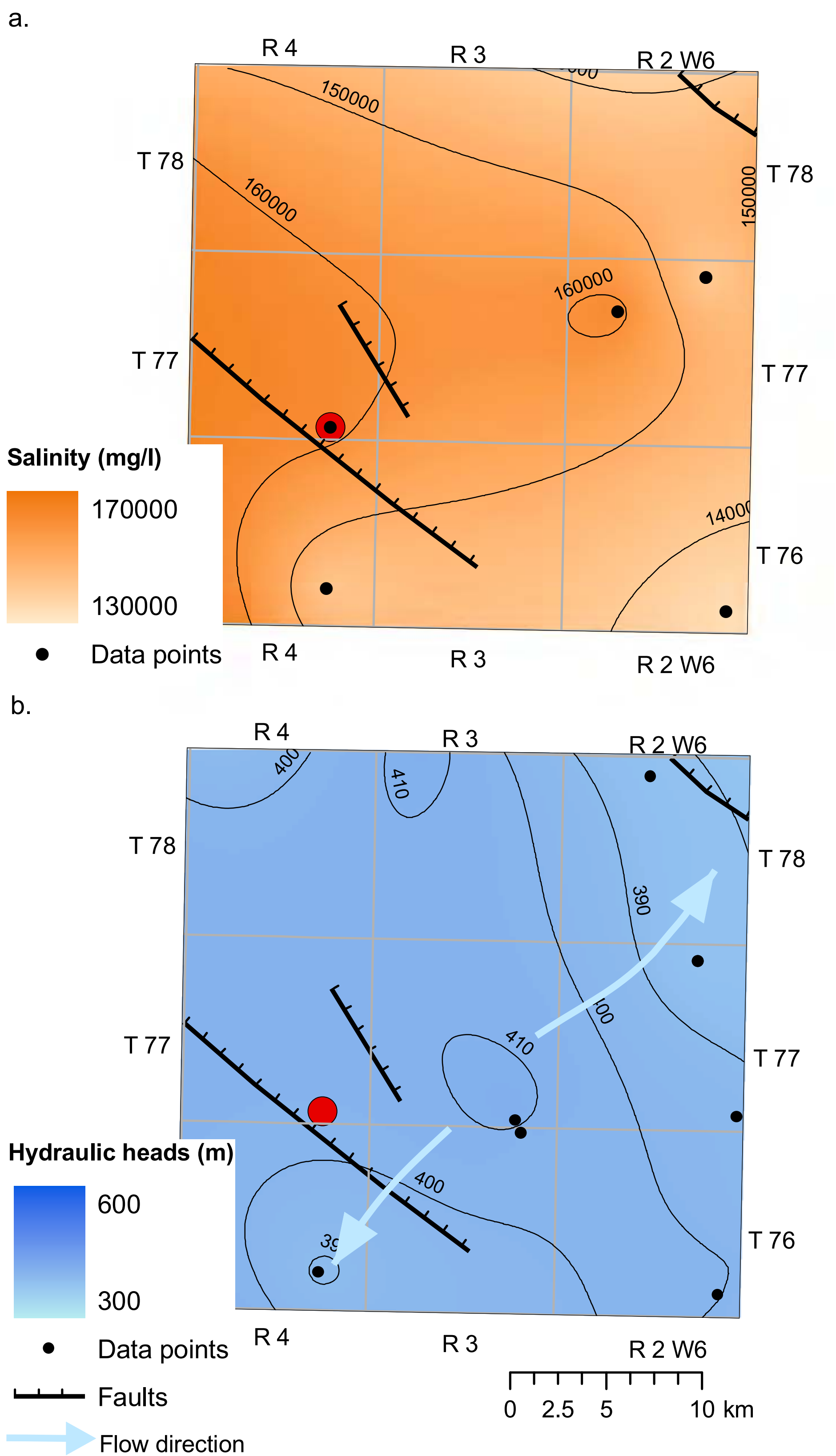


Figure 57. Distribution of a) salinity and b) hydraulic heads in the Belloy-Stoddart aquifer in the Rycroft area. The location of the Rycroft injection site is also shown.

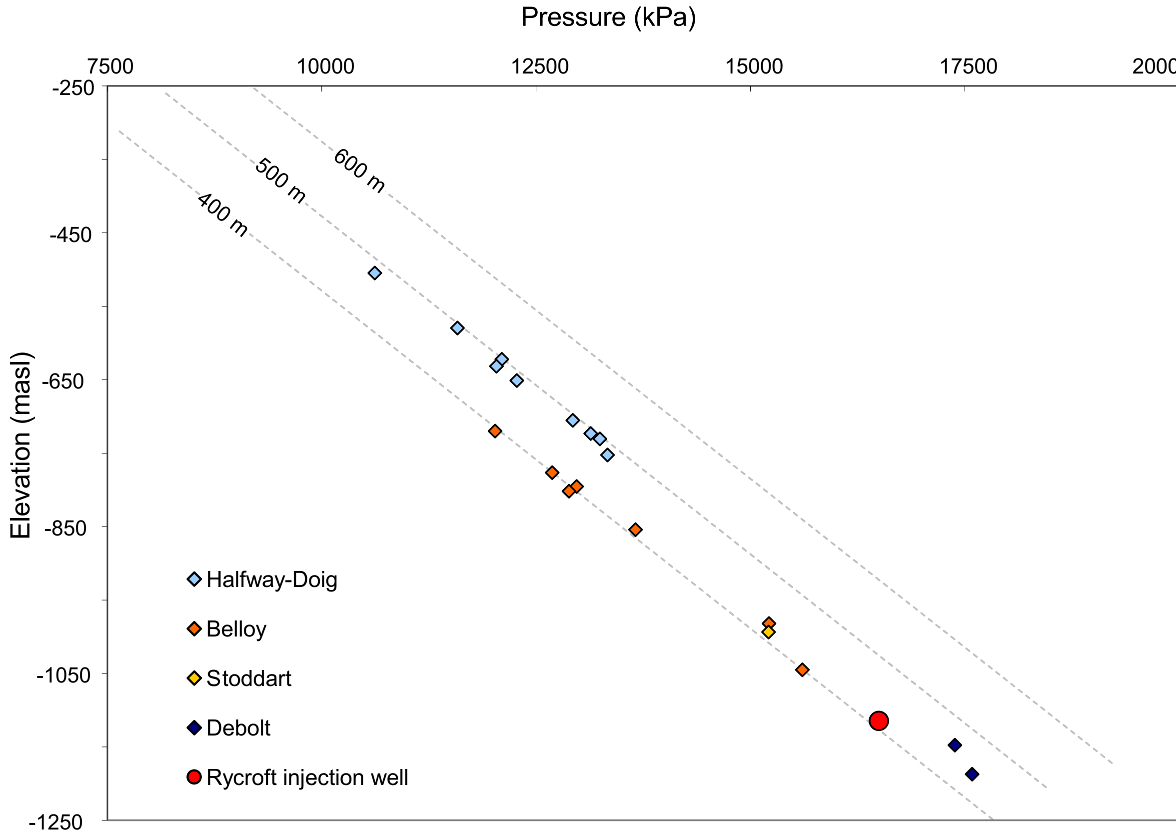


Figure 58. Distribution of pressure versus elevation in the injection strata (Kiskatinaw Fromation) and adjacent formations in the Rycroft area. The dashed lines delineate pressure-elevation trends with equal hydraulic-head values and the potential for vertical flow may be inferred perpendicular to those lines from high to low values.

formations are of the same order of magnitude, 72 mD in the Belloy Formation and 33 mD in the Kiskatinaw Formation. The apparent discrepancy probably is due to the lateral and vertical heterogeneity of the Kiskatinaw and Belloy formations. The DST permeability values should be more representative with respect to the velocity of formation water flow because DSTs cover a larger portion of the respective aquifer.

Table 11. Well-scale porosity and permeability values obtained from measurements in core plugs from the Belloy (13 wells) and Kiskatinaw (2 wells) formations, and permeability values calculated from 10 drillstem test analyses in the Rycroft area.

	Porosity (%)			Horiz. Perm. (mD)			Vert. Perm. (mD)			DST Perm. (mD)		
Formation	Min	Max	Avg	Min	Max	Median	Min	Max	Median	Min	Max	Median
Belloy	1	12	6.4	0.01	217	2.4	0.01	7	0.2	15.92	163	72
Kiskatinaw	3	18	9.5	0.05	274	17.5	0.01	143	2.7	0.48	1660	33

Flow of Formation Water

Flow conditions of formation water in the Kiskatinaw aquifer in the Rycroft area are close to stagnant, the salinity decreasing eastward from approximately 165 g/l to less than 140 g/l. Based on the range in pressure and salinity in the Kiskatinaw and Belloy formations, these two units form a contiguous aquifer in the Rycroft area. Interpolation from the regional hydraulic-head distribution in the Belloy-Stoddart aquifer results in a hydraulic gradient of approximately 0.5 m/km directed towards the north-northwest at the Rycroft injection site.

5.4 Dunvegan

The Dunvegan local-scale study area is defined around the Dunvegan gas field and extends from 55.85°N to 56.12°N and 118.23°W to 118.70°W (Townships 80-81, Ranges 3-4W6 plus three section on all four sides) (Figure 12). Injection takes place into a depleted gas reservoir in the Kiskatinaw Formation of the Stoddart Group. The study area is located 5 km north of the Rycroft local-scale study area, where acid gas is also disposed of in the Kiskatinaw Formation.

5.4.1 Geology

Similar to the Rycroft area, sediments of the Kiskatinaw Formation in the Dunvegan area were deposited in a fluvial/estuarine to shallow marine sequence, dominantly consisting of sandstones with interbedded shales (Barclay et al., 1990). In the local-scale study area, the Kiskatinaw Formation is on average 25 m thick (Figure 59a). The dominant structural feature is the NW-SE trending Dunvegan Fault, a normal fault along which the Debolt Formation is offset downwards in the northeast. The syn-depositional character of the Dunvegan Fault with respect to the deposition of the Kiskatinaw Formation is depicted by an abrupt change in the formation thickness, which is absent in areas above the "Dunvegan Horst" and reaches up to 50 m along the down-faulted edge of the structure (Figure 60).A series of additional normal faults parallel to the Dunvegan Fault downstep into the graben. In addition, syn-depositional NE-SW trending normal faults cause local thickening of the Kiskatinaw Formation in the northwest corner of the study area (Figures 59a). A SW-NE trending normal fault forms the northwest boundary to the Dunvegan Horst and the Dunvegan gas field. The acid-gas injection site is located just to the northeast of the Dunvegan Fault where injection takes place into the 30 m thick Kiskatinaw sandstones that fill the southwest flank of the half graben (Figure 60).

The injection interval is overlain locally by approximately 15 m thick anhydrites and dolostones of the Taylor Flat Formation. Over the entire local study area, the Taylor Flat Formation ranges in thickness between less than 5 m above the Dunvegan Horst and 60 m in the northwest (Figure 59b).The shales of the Golata Formation that provide the bottom seal to the Kiskatinaw sandstones range in thickness between 0 m above the Dunvegan Horst and 60 m in the northeast of the study area (Figure 60). At the injection site, the Golata Formation is 25 m thick.

5.4.2 Hydrogeological Characteristics and Rock Properties

Relatively few hydrogeological data exist for the Kiskatinaw Formation in the Dunvegan area, because the petroleum industry has focused mainly on hydrocarbon occurrences in the overlying and underlying stratigraphic successions. However, the regional hydrogeological analysis indicated a weak or non-existing hydraulic separation of the Belloy and Kiskatinaw aquifers due to the lack of an effective intervening aquitard in the Rycroft area. Therefore, in the following the Belloy and Kiskatinaw formations will be considered as a combined aquifer.

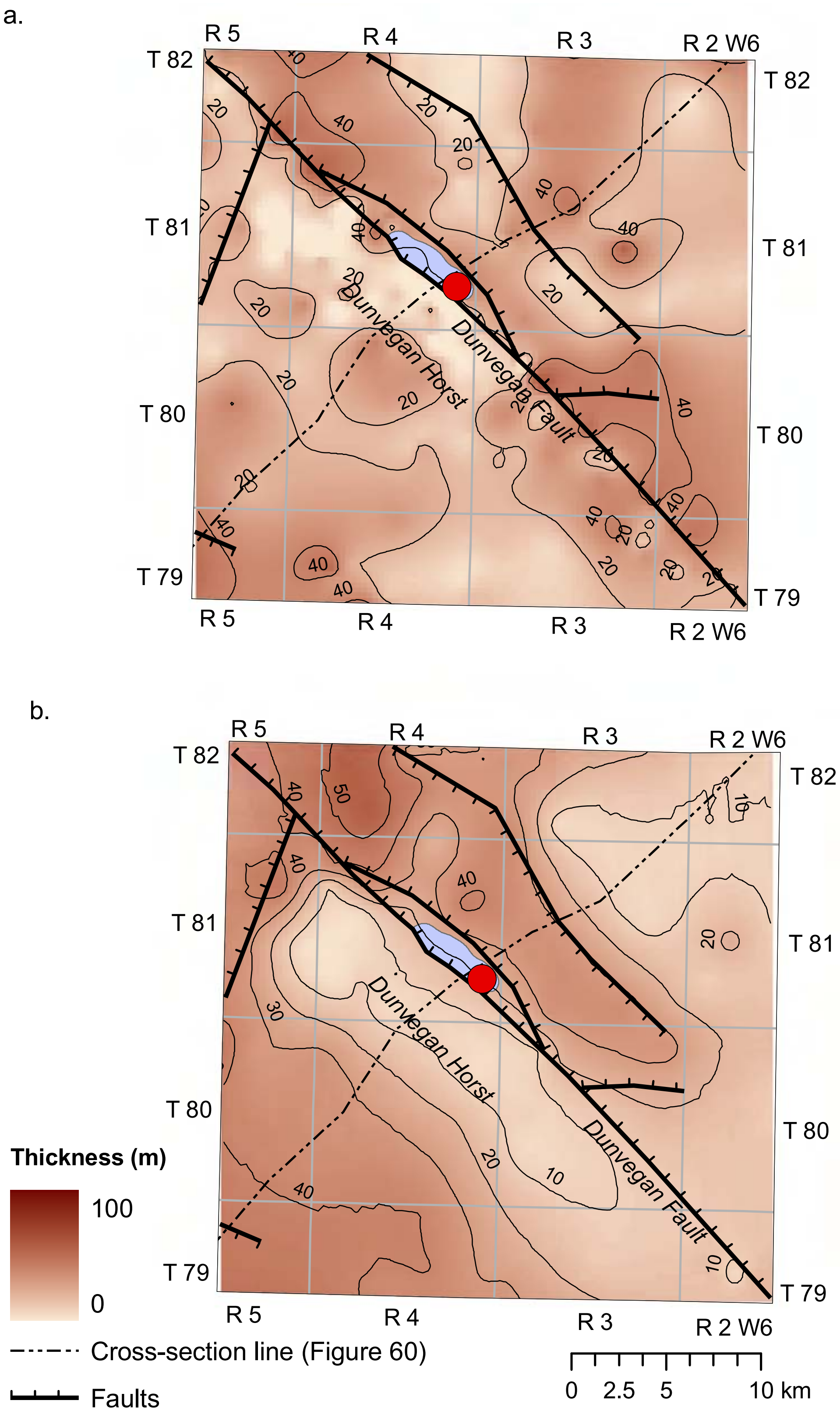


Figure 59. Isopach maps in the Dunvegan local-scale study area: a) Kiskatinaw Formation and b) Taylor Flat Formation. The location of the Dunvegan injection site and the outline of the Dunvegan gas pool (purple) are also shown.

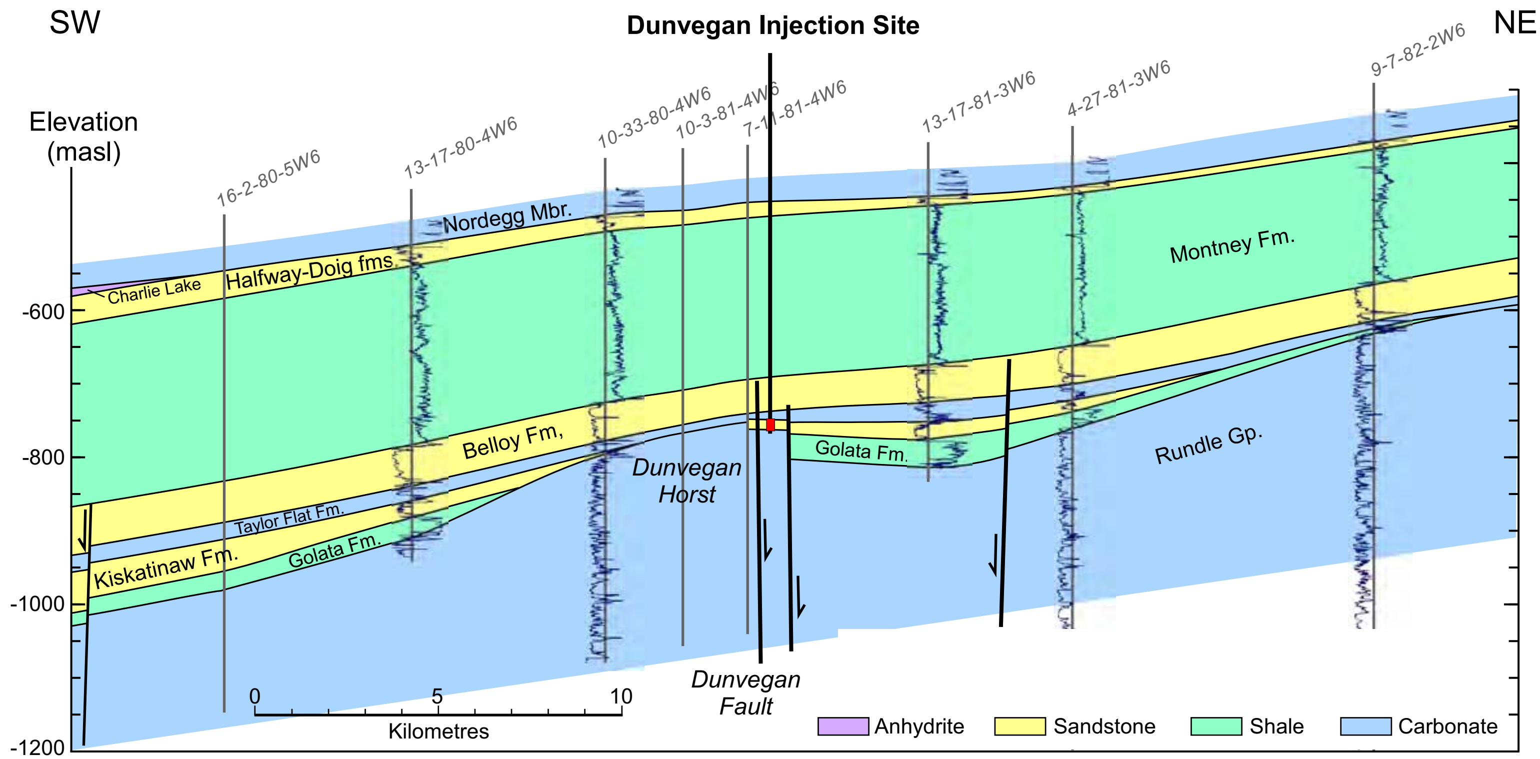


Figure 60. Local-scale structural cross-section showing the general lithology distribution from the top of the Rundle Group to the base of the Jurassic Nordegg Member in the Dunvegan area. The inection interval (red bar) is located in the Kiskatinaw Formation. The location of the line of cross-section is shown in Figure 59.

Chemistry of Formation Waters

The major constituents of formation water in the Belloy and Kiskatinaw formations are chloride (84.1 g/l) and sodium (49.1 g/l), making up approximately 95% of the total dissolved solids (Table 12). Calcium, potassium, magnesium, sulphate and bicarbonate are present in minor concentrations (Figure 56b).

In the Dunvegan area, chemical analyses of Belloy-Stoddart formation water are restricted to the northwest and southeast corners. The salinity decreases from approximately 160 g/l in the northwest to less than 125 g/l in the center and in the southeast (Figure 61a). The regional distribution of formation water salinity in the Belloy-Stoddart aquifer (Figure 33) suggests that a tongue of fresher salinity water (< 125 g/l) reaches into the Dunvegan area from the northeast, terminating against the Dunvegan Fault and the isopach low of the Kiskatinaw Formation in the northwest (Figure 59a). The average in-situ density of formation water in the Belloy-Stoddart aquifer was estimated to be 1090 kg/m^3, using the methods presented in Adams and Bachu (2002).

Table 12. Major ion chemistry of brines from the Belloy-Stoddart aquifer in the Dunvegan area (concentrations in g/l).

	Na	K	Ca	Mg	Cl	SO_4	HCO_3	TDS
Belloy								
16-26-081-04-W-6	44.8	0.9	2.5	0.6	72.9	2.92	0.14	123.7
14-21-079-02-W-6	44.2	0.6	2.8	0.7	73.0	2.76	0.22	123.6
12-22-081-04-W-6	37.0	0.6	2.6	0.8	60.6	4.30	0.69	105.6
Kiskatinaw								
16-16-082-04-W-6	54.8	0.5	4.9	1.2	94.8	2.11	0.23	157.8
16-16-082-04-W-6	53.1	0.5	4.8	1.2	91.9	2.36	0.20	153.4
06-15-082-04-W-6	48.0	0.7	3.5	1.1	82.0	2.11	0.13	136.9
02-31-081-04-W-6	58.0		5.0	1.5	101.4	1.75	0.12	167.7
02-31-081-04-W-6	60.1		6.0	1.7	96.0	1.60	0.14	158.4
Minimum	37.0	0.5	2.5	0.6	60.6	1.60	0.12	105.6
Maximum	58.0	0.9	6.0	1.7	101.4	4.30	0.69	167.7
Average	49.1	0.6	4.0	1.1	84.1	2.49	0.23	140.9

Pressure Regime

Hydraulic-head values in the Belloy-Stoddart aquifer decrease southeastward from 420 m to less than 380 m (Figure 61b), inferring southeastward-directed flow of formation water. The relatively low hydraulic gradient suggests good lateral hydraulic communication within the aquifer.

The distribution of pressure versus elevation shows distinctively different grouping of data from the Belloy-Stoddart aquifer versus data from the overlying and underlying aquifers (Figure 62). Pressure data from the Triassic to Jurassic aquifers and from the Rundle aquifer plot along trends that correspond to notably higher hydraulic-head values (500 m and 550 m, respectively), which indicates that intervening Montney and Golata aquitards effectively retard cross-formational flow. The potential for vertical flow is downwards from the Halfway-Doig aquifer, and upwards from the Rundle into the Belloy-Stoddart aquifer. The exception are areas along the Dunvegan Fault, where the Upper Debolt is adjacent to the

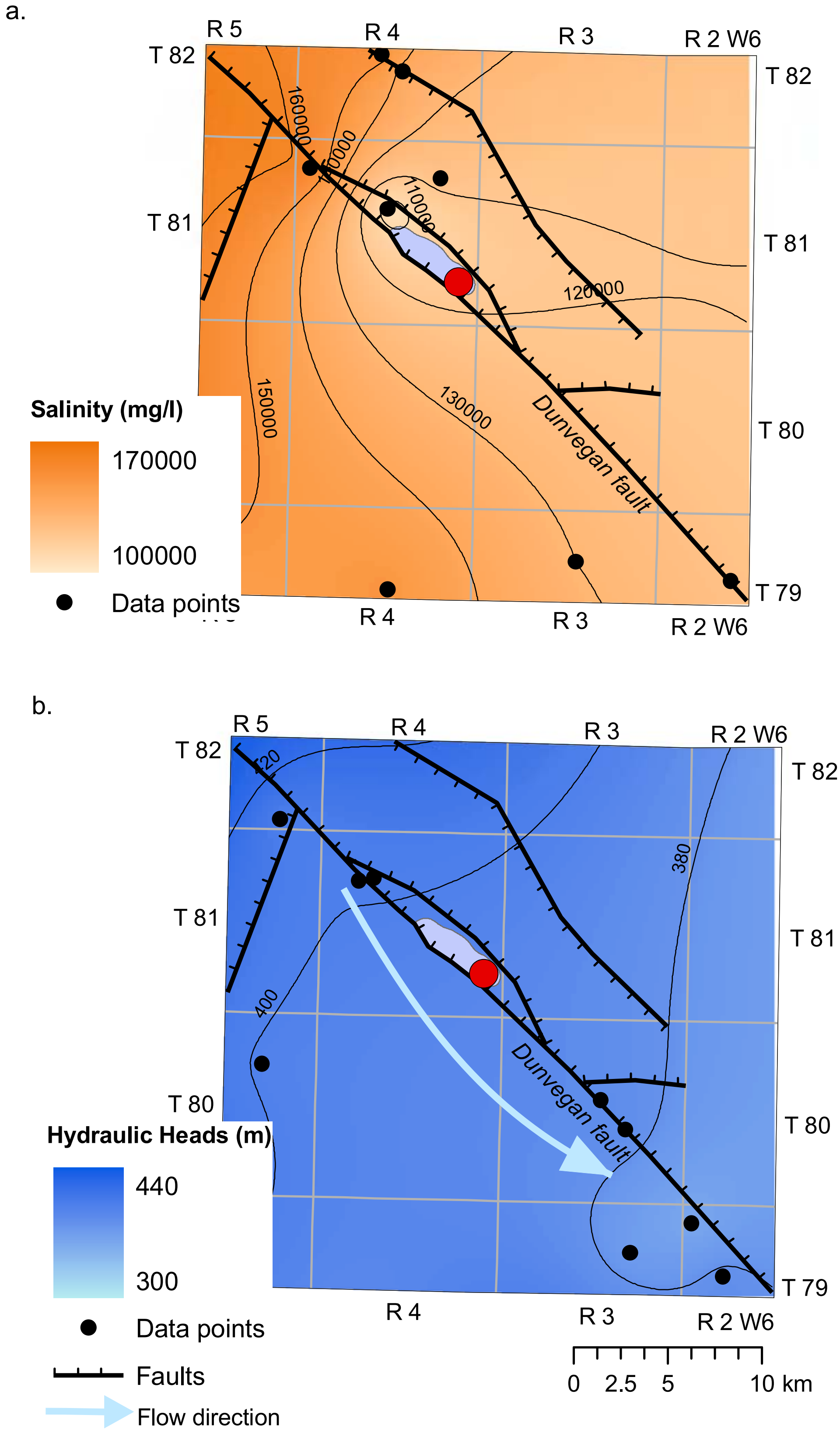


Figure 61. Distribution of a) salinity and b) hydraulic heads in the Belloy-Stoddart aquifer in the Dunvegan area. The location of the Dunvegan injection site and the outline of the Dunvegan Kiskatinaw gas pool are also shown.

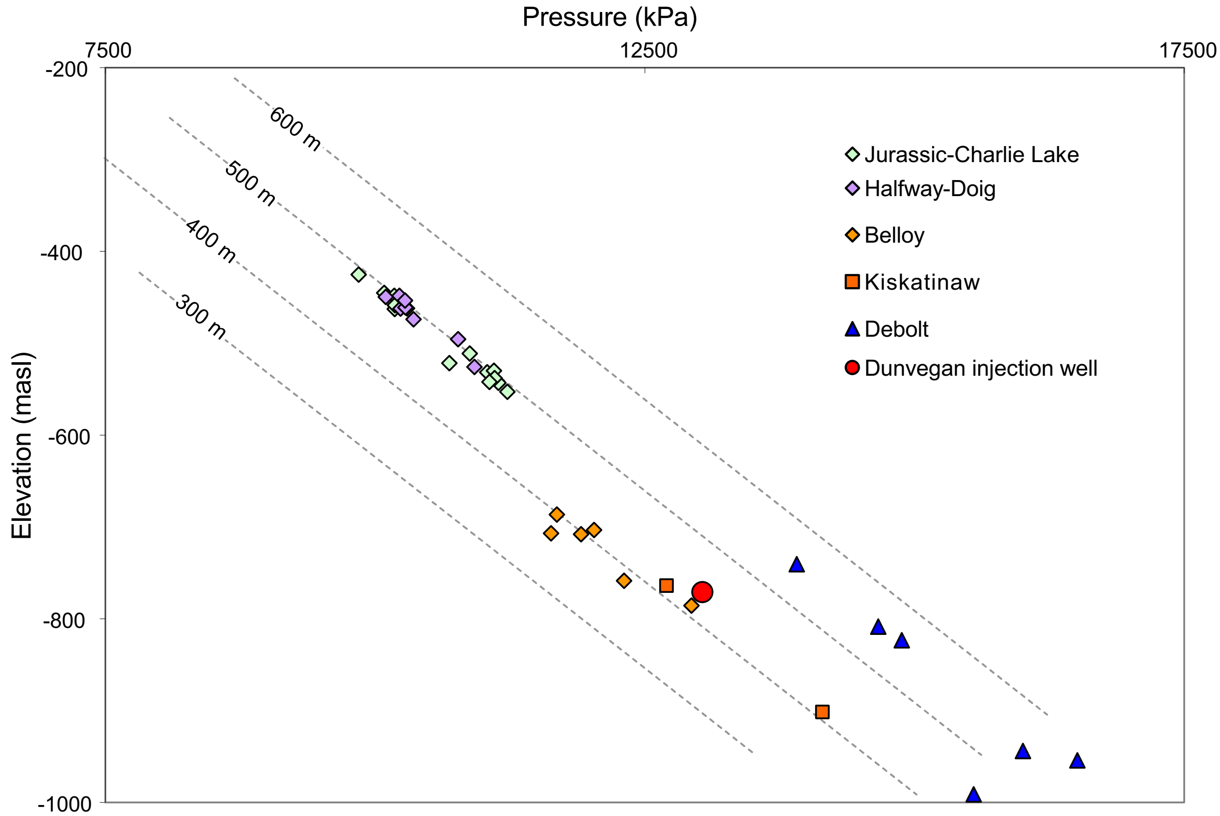


Figure 62. Distribution of pressure versus elevation in the injection strata (Kiskatinaw Formation) and adjacent formations in the Dunvegan area. The dashed lines delineate pressure-elevation trends with equal hydraulic-head values and the potential for vertical flow may be inferred perpendicular to those lines from high to low values.

Kiskatinaw Formation, and the upper part of the Rundle aquifer is in direct hydraulic contact with the Belloy-Stoddart aquifer (Figure 60).

Rock Properties

The range and average of well-scale porosity and permeability values for the injection horizon, the Kiskatinaw Formation, and the overlying Belloy Formation are shown in Table 13. The Kiskatinaw Formation has an average porosity of 10 %, a median horizontal permeability of 139 mD and a median vertical permeability of 30 mD. Only one core exists of the Belloy Formation with values of 14 % porosity, 8 mD horizontal permeability and 10 mD vertical permeability, which is within the ranges of respective values in the Kiskatinaw Formation. Also shown are reservoir-scale permeability values calculated from drillstem tests that were performed in the Belloy-Stoddart aquifer. These values range over four orders of magnitude with a median permeability of 34 mD.

Table 13. Well-scale porosity and permeability values obtained from measurements in core plugs from the Kiskatinaw (6 wells) and Belloy (1 well) formations in the Dunvegan area. Also shown are permeability values calculated from 8 drillstem test analyses performed in the Belloy-Stoddart aquifer.

<table>
<tr><th></th><th colspan="3">Porosity (%)</th><th colspan="3">Horiz. Perm. (mD)</th><th colspan="3">Vert. Perm. (mD)</th><th colspan="3">DST Perm. (mD)</th></tr>
<tr><td>Formation</td><td>Min</td><td>Max</td><td>Avg</td><td>Min</td><td>Max</td><td>Median</td><td>Min</td><td>Max</td><td>Median</td><td>Min</td><td>Max</td><td>Median</td></tr>
<tr><td>Belloy</td><td></td><td></td><td>14</td><td></td><td></td><td>8</td><td></td><td></td><td>10</td><td rowspan="2">0.37</td><td rowspan="2">356</td><td rowspan="2">34</td></tr>
<tr><td>Kiskatinaw</td><td>3</td><td>20</td><td>10</td><td>1.9</td><td>1194</td><td>139</td><td>0.02</td><td>61</td><td>30</td></tr>
</table>

Flow of Formation Water

The distributions of hydraulic heads and salinity are similar in the Belloy and Kiskatinaw formations, both forming the contiguous Belloy-Stoddart aquifer in the Dunvegan area. The Belloy-Stoddart aquifer is noticeably underpressured with respect to the overlying Halfway-Doig aquifer and the underlying Rundle aquifer, indicating that it is vertically isolated and that the bounding aquitards are effective barriers to vertical leakage. Flow of formation water is towards the southeast, sub-parallel to the Dunvegan Fault, deviating from the regional northeastward flow direction. At the injection site, the hydraulic gradient is approximately 1.5 m/km. Formation water salinity decreases in the direction of flow from 165 g/l to less than 120 g/l.

5.5 Pouce Coupe

The Pouce Coupe local-scale study area extends from 55.90˚N to 56.25˚N and 119.73˚W to 120.50˚W (Townships 80 to 83 and Ranges 12 to 16 W6), crossing the Alberta – British Columbia border at a longitude of 120.0˚W (Figure 12). Two acid-gas injection operations are located in this area. At Parkland, acid gas is injected into a depleted Kiskatinaw gas pool, whereas at Parkland acid-gas injection occurs in the Belloy aquifer.

5.5.1 Geology

The Kiskatinaw Formation with a maximum thickness of 200 m in the Fort St. John Graben (Figure 63a) is the injection target at the Parkland site. At the injection site, the entire Kiskatinaw Formation is approximately 100 m thick and thickens to 200 m north of the Gordondale Fault (Figure 64). The Kiskatinaw Formation consists of a porous basal sandstone unit, which is up to 30 m thick (Barclay et al., 1990) and forms the main reservoir unit, overlain by a succession of interbedded sandstones and shales. The basal sandstones incise the underlying Golata Formation and were deposited during graben subsidence in a fluvio-estuarine environment. The upper succession of Kiskatinaw Formation represents shoreline to shallow-marine deposits (Barclay et al., 1990). Overlying the Kiskatinaw Form are fossiliferous dolostones of the Taylor Flat Formation (Figure 65). Due to its generally low permeability, the Taylor Flat Formation locally forms an aquitard between the Kiskatinaw Formation and the overlying Belloy Formation, specifically within the Fort St. John Graben, where the Taylor Flat Formation is up to 250 m thick (Figure 63b). The 20-80 m thick shales of the Golata Formation form a regional aquitard at the base of the Stoddart Group.

The Belloy Formation, the second injection target in the Pouce Coupe local-scale study area, ranges in thickness between 220 m within the Fort St. John Graben and 40 m outside the main graben (Figure 66a). The maximum thickness of the Belloy Formation is reached along the southern flank of the Fort St. John Graben, north of the Gordondale fault. At the Pouce Coupe injection site, the total thickness of the Belloy

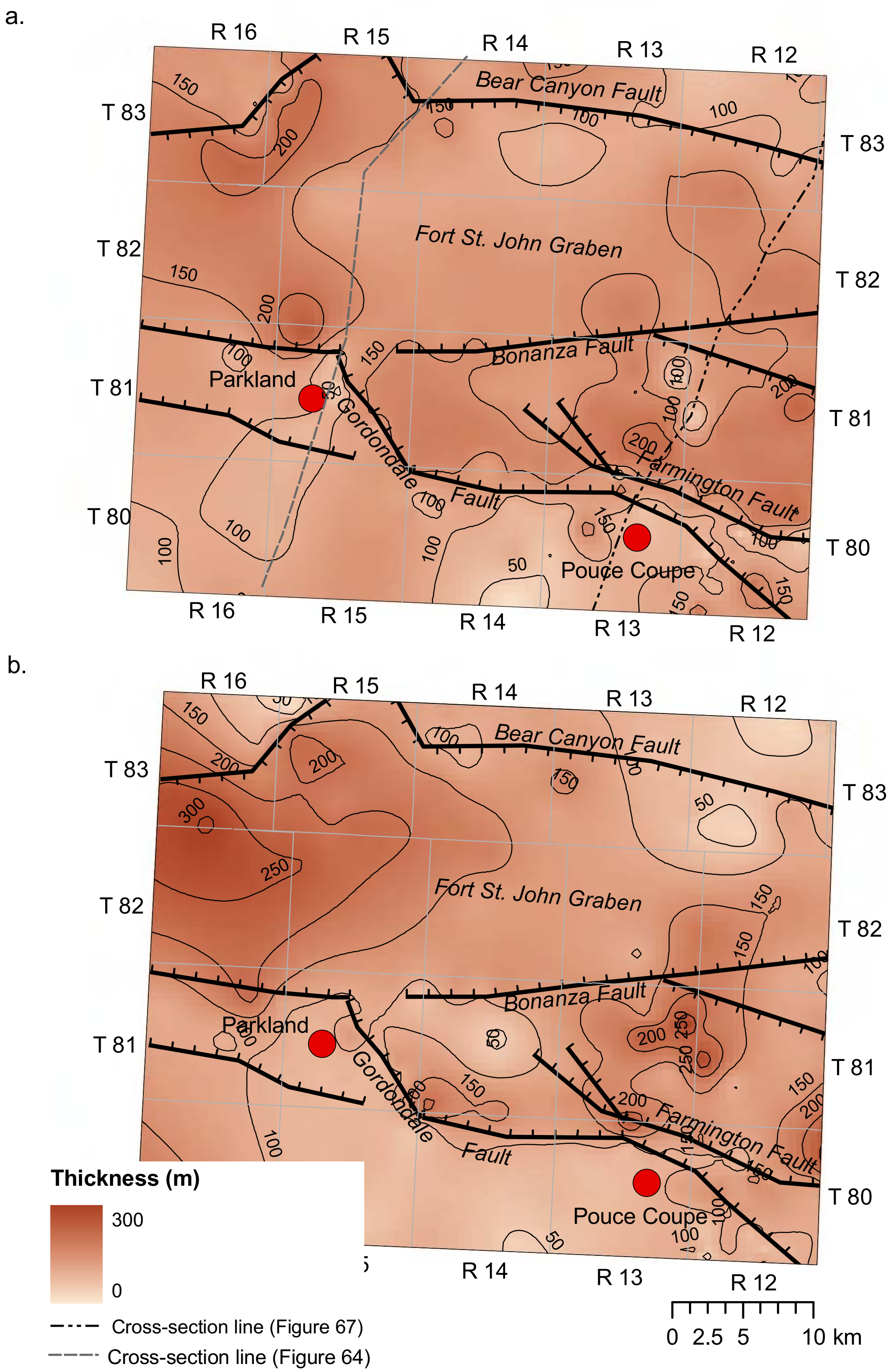


Figure 63. Isopach maps in the Pouce Coupe local-scale study area: a) Kiskatinaw Formation and b) Taylor Flat Formation. The location of the Parkland and Pouce Coupe injection sites are also shown.

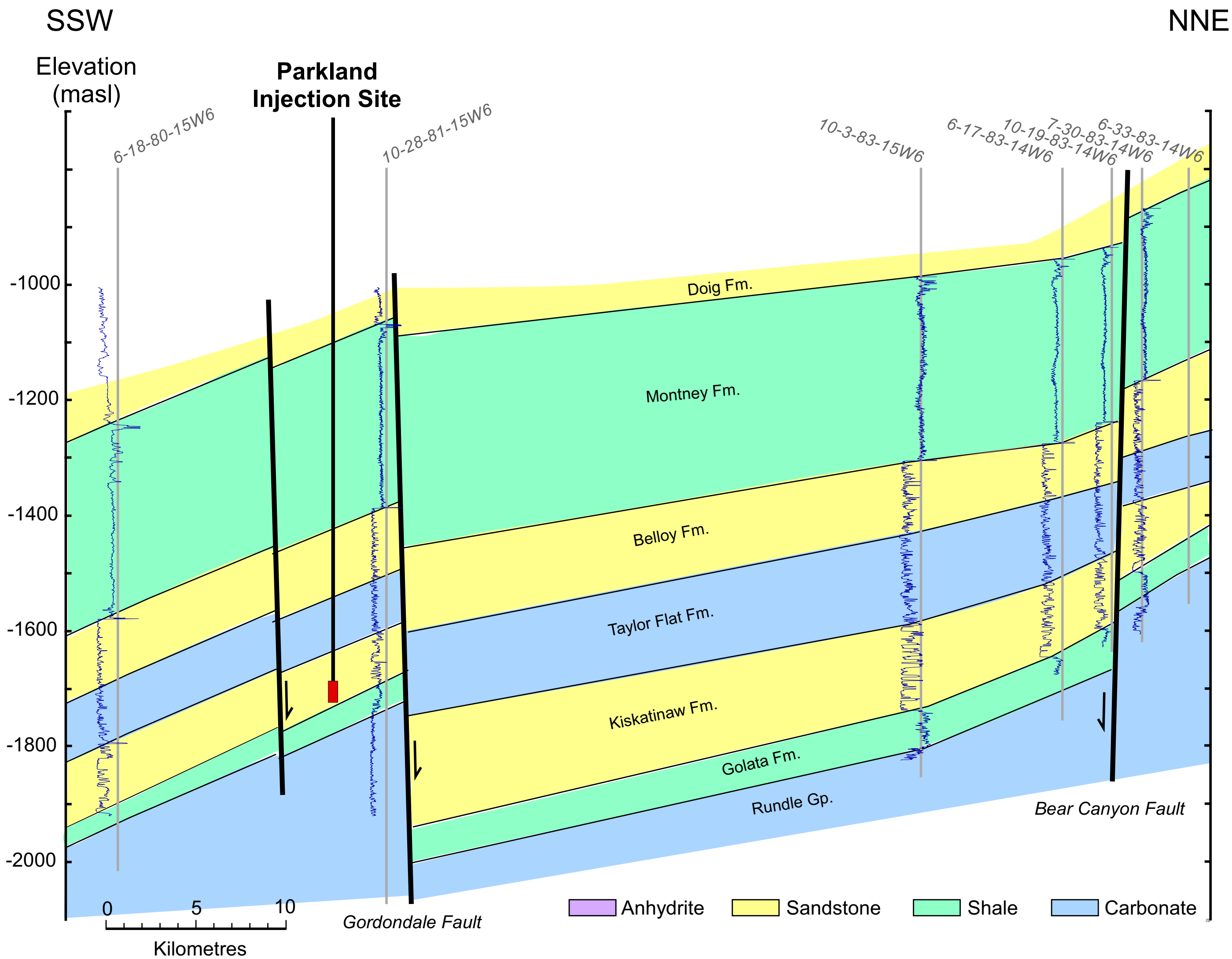


Figure 64. Local-scale structural cross-section showing the general lithology distribution from the top of the Rundle Group to the base of the Doig Formation in the Pouce Coupe area. The injection interval (red bar) is located in the basal sandstone unit of the Kiskatinaw Formation. The gamma-ray logs show the intra-formational lithofacies heterogeneity, particularly in the Taylor Flat and Kiskatinaw formations. The location of the line of cross-section is shown in Figure 63.

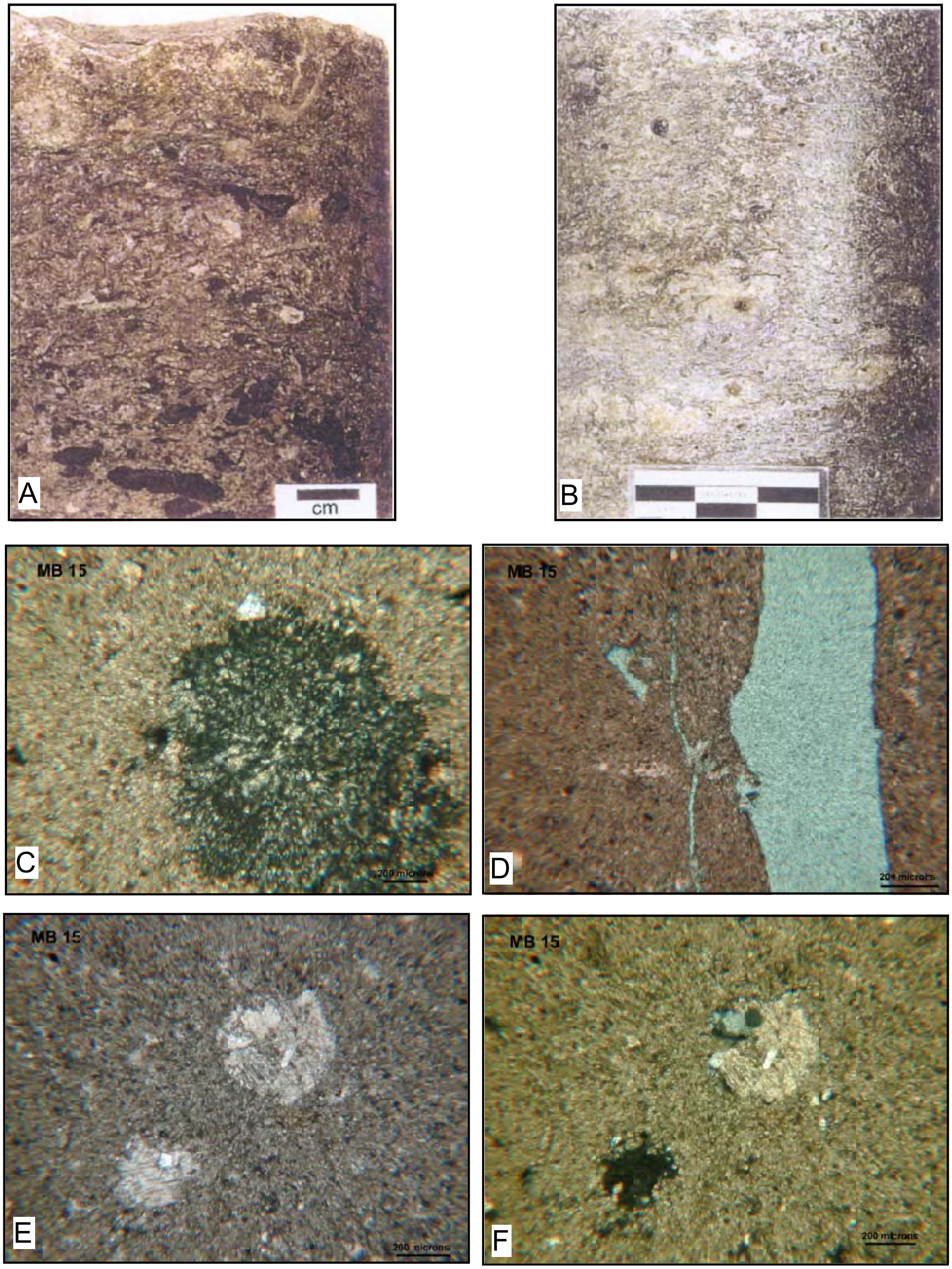


Figure 65. Core and thin section photographs of the Taylor Flat Formation dolostone. The core photographs (A and B) show fossiliferous, lime grainstones (from Barclay, 2000). The thin section photographs (C to F) show minor amount of vuggy porosity and some fracture porosity in the dolostone. Thin section photographs are from Taylor Flat samples from the Parkland injection site (7-03-083-16W6).

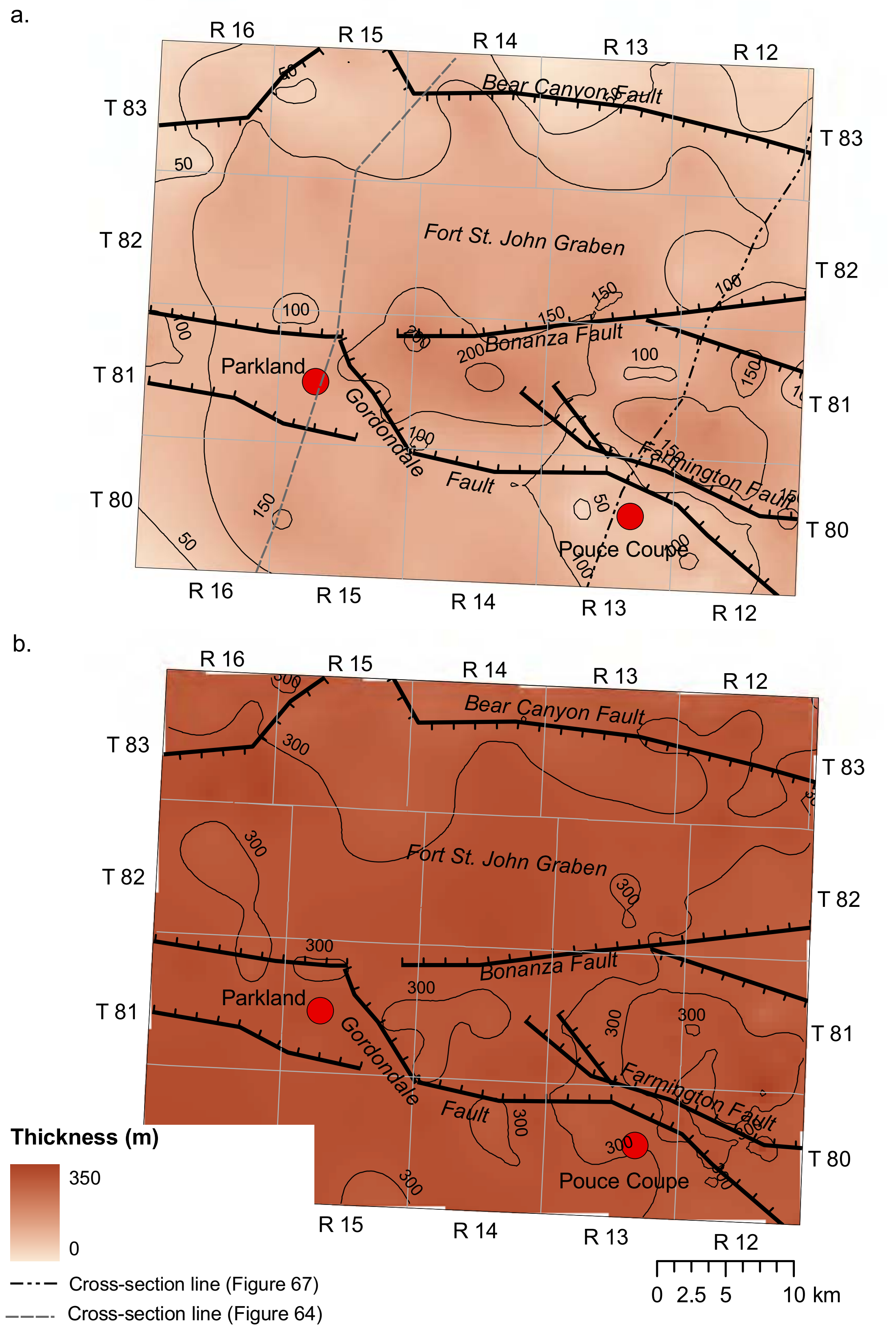


Figure 66. Isopach maps in the Pouce Coupe local-scale study area: a) Belloy Formation and b) Montney Formation. The location of the Parkland and Pouce Coupe injection site is also shown.

Formation is approximately 75 m (Figure 67), with a net pay given by the operator of 7 m (based on a 6 % porosity cut-off). Within the study area, the Belloy Formation consists of interbedded sandstone and dolostone with mainly inter-granular porosity (Figure 68). The amount of dolostone increases towards the west of the study area. The Belloy injection interval is overlain by approximately 300 m of shale and siltstone of the Triassic Montney Formation (Figure 66b), which forms an effective seal.

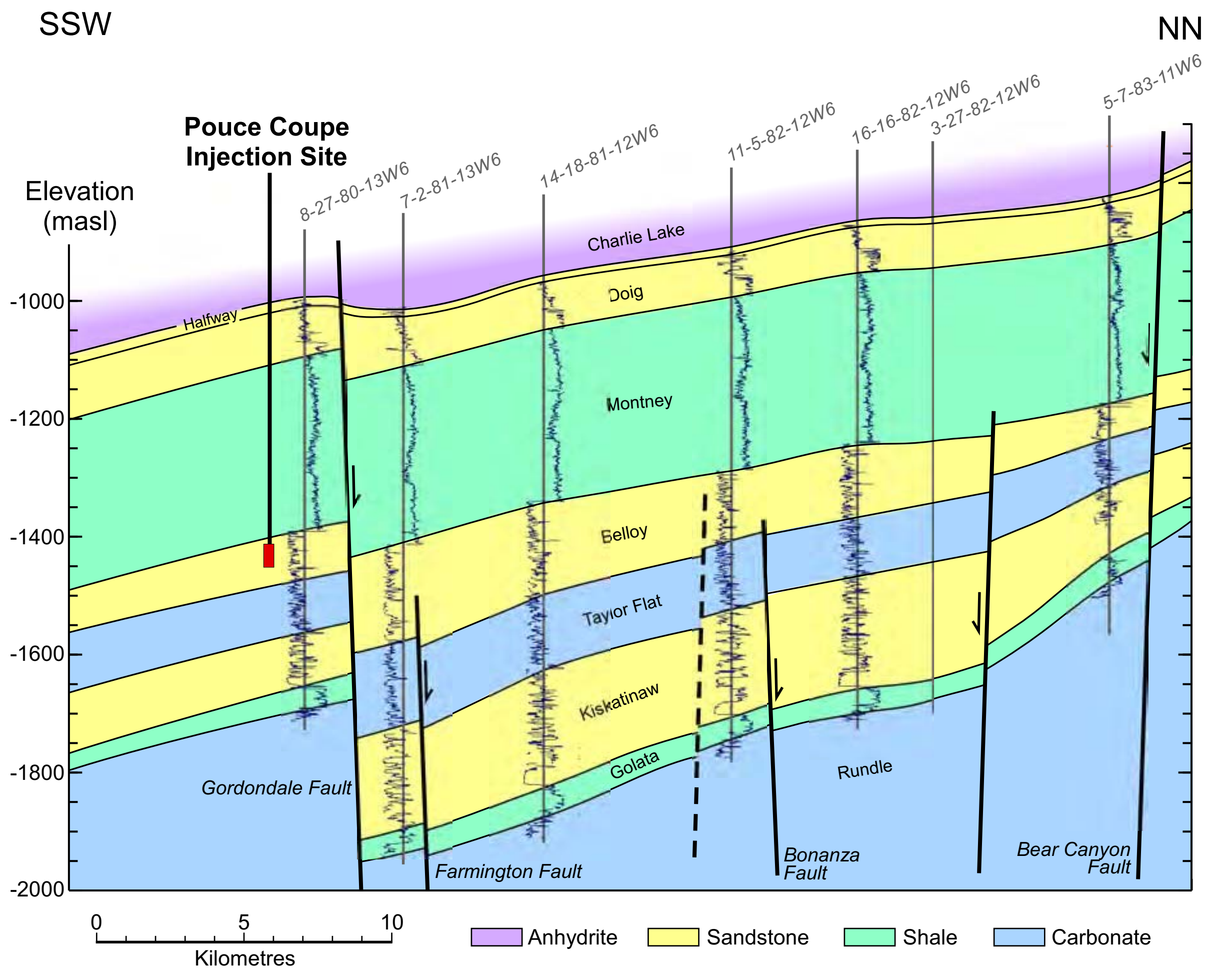


Figure 67. Local-scale structural cross-section showing the general lithology distribution from the top of the Rundle Group to the base of the Charlie Lake Formation in the Pouce Coupe area. The injection interval (red bar) is located in the Belloy Formation The gamma-ray logs show the intra-formational lithofacies heterogeneity, particularly in the Taylor Flat and Kiskatinaw formations. The location of the line of cross-section is shown in Figure 66.

Structurally, the Pouce Coupe area covers the western part of the Fort St. John Graben. The main structural features are the Gordondale Fault and the Bear Canyon Fault, which outline the Fort St. John Graben to the south and to the north, respectively. Along the Gordondale Fault, the top of the Golata Formation is offset by up to 200 m, whereas the top of the Belloy Formation is offset by only approximately 50 m or less (Figures 64 and 67). The faulting of strata along the edges of the Fort St. John Graben causes the partial or even complete disconnect of hydrostratigraphic units, particularly the Kiskatinaw and Belloy aquifers, as well as the Golata aquitard (Figures 64 and 67).

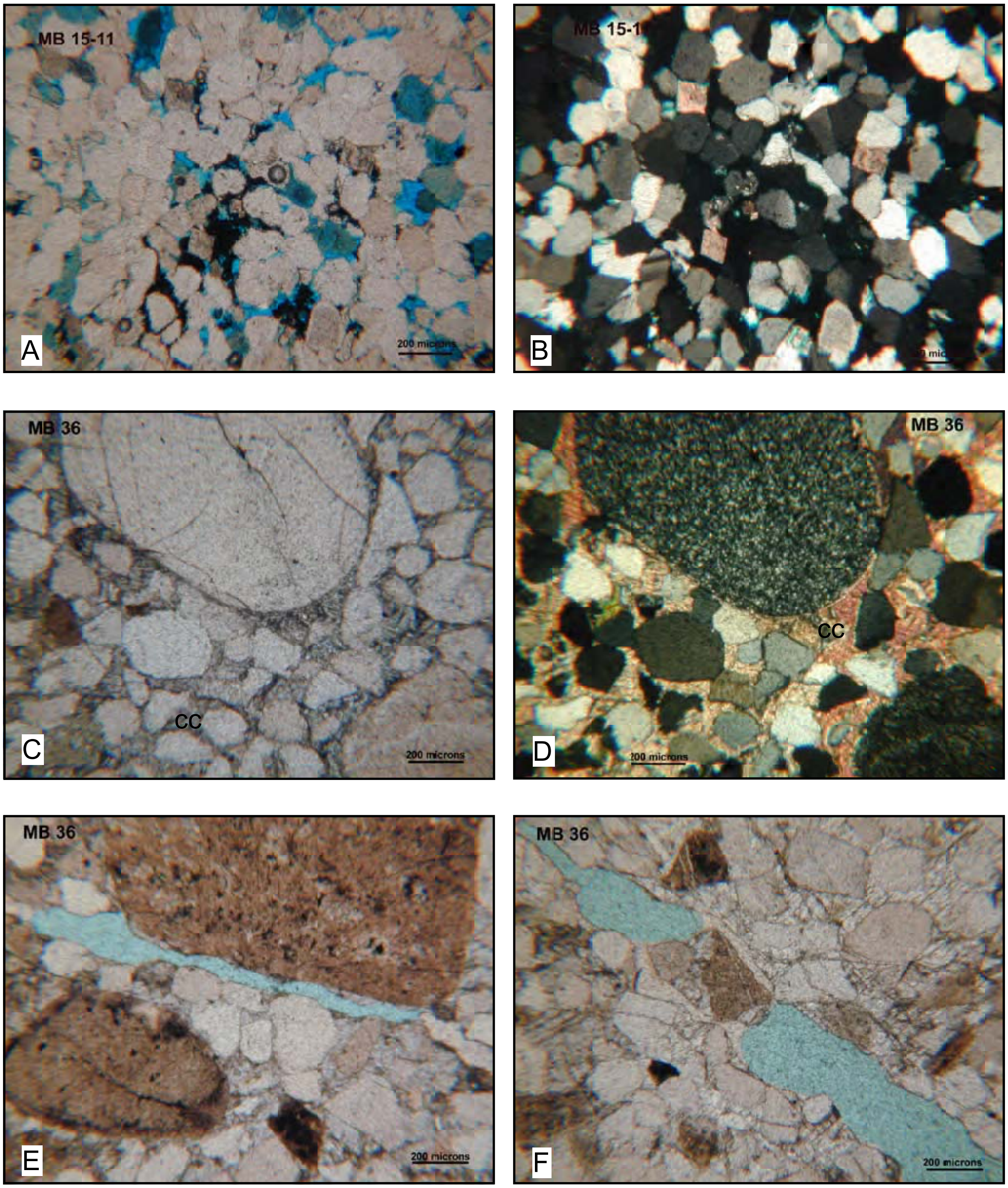


Figure 68. Pictures A and B are from the Belloy Formation at the Pouce Coupe site and show intergranular porosity. Figures C to F show thin-section photographs of the Belloy sandstone at the Wombley site. Note the calcite cements (CC) surrounding quartz grains (Photographs C and D). Fracture porosity in C and D is stained blue.

5.5.2 Hydrogeological Characteristics and Rock Properties

Although, the succession from the Belloy to the Kiskatinaw Formation forms the contiguous Belloy-Stoddart aquifer on a regional scale, thickening of tight carbonates in the Taylor Flat Formation, especially within grabens, resulted in a widespread aquitard between the Belloy and Kiskatinaw formations in the Pouce Coupe area.

Chemistry of Formation Waters

The formation water in the Kiskatinaw and Belloy formations is of a Na-Cl type. The average concentrations of sodium and chloride in the Kiskatinaw Formation (51.9 g/l sodium and 96.3 g/l chloride) are higher than in the overlying Belloy Formation (48.3 g/l sodium and 83.7 g/l chloride) (Table 14). Calcium, magnesium, sulphate and bicarbonate are present in minor concentrations (Figure 59b). The salinity in the Kiskatinaw aquifer increases from less than 140 g/l in the west and outside the boundaries of the Fort St. John graben to approximately 200 g/l in the graben center in the east (Figure 69a). In contrast, salinities in the overlying Belloy aquifer range between approximately 120 g/and 150 g/l in most of the study area, except for the northwest corner, where salinity reaches up to 170 g/l (Figure 69b).

The average in-situ brine density in the Pouce Coupe area is 1100 kg/m^3 for the Kiskatinaw Formation, compared to 1087 kg/m^3 for the Belloy Formation.

Table 14. Major ion chemistry of brines from the Kiskatinaw and Belloy aquifers in the Pouce Coupe area (concentrations in g/l).

	Na	K	Ca	Mg	Cl	SO_4	HCO_3	TDS
Kiskatinaw								
07-09-080-12-W-6	34.1		3.4	0.6	58.9	2.1	0.16	99.3
11-10-080-12-W-6	49.6		7.2	1.2	91.9	0.9	0.29	150.9
10-26-081-16-W-6	50.5		4.3	1.2	86.8	1.9	1.49	145.5
06-25-080-12-W-6	41.1	0.3	7.9	1.0	79.3	0.9	0.41	130.4
07-30-083-12-W-6	52.9	0.2	6.6	1.2	95.5	1.4	0.27	157.7
06-03-081-13-W-6	62.7	0.3	10.7	2.0	120.9	0.4	0.23	196.7
07-20-080-12-W-6	64.7	0.4	10.0	1.8	122.0	0.9	0.29	199.6
03-34-080-13-W-6	44.0	0.3	5.3	0.9	78.7	1.3	0.35	130.3
10-18-083-13-W-6	56.5	0.4	6.7	2.6	105.8	1.0	0.09	172.7
10-05-080-12-W-6	47.2	0.3	6.8	1.4	88.0	1.0	0.45	144.6
10-26-080-14-W-6	50.4	0.3	6.3	0.7	90.0	1.1	0.04	148.4
10-18-081-13-W-6	62.8	0.6	13.6	2.1	126.4	0.7	0.21	205.7
06-26-083-13-W-6	48.1		6.1	1.6	88.2	1.6	0.33	145.7
07-20-080-12-W-6	62.1	0.4	10.2	1.1	116.0	1.0	0.40	190.5
Minimum	34.1	0.2	3.4	0.6	58.9	0.4	0.0	99.3
Maximum	64.7	0.6	13.6	2.6	126.4	2.1	1.5	205.7
Average	51.9	0.3	7.5	1.4	96.3	1.2	0.4	158.4
Belloy								

	Na	K	Ca	Mg	Cl	SO_4	HCO_3	TDS
07-27-081-16-W-6	37.5		4.9	1.2	68.6	1.15	0.68	113.7
04-36-082-16-W-6	58.7		4.5	0.3	98.6	0.98	0.29	163.2
08-33-082-16-W-6	46.1		4.7	0.8	79.8	2.14	0.36	133.7
06-09-083-16-W-6	60.6		4.5	0.9	102.8	1.35	0.56	170.4
07-27-081-16-W-6	45.9		2.5	0.7	75.8	1.25	0.41	126.5
07-27-081-16-W-6	44.4		2.6	0.6	73.6	1.22	0.62	122.9
06-15-081-14-W-6	51.2	1.0	6.6	1.3	93.4	1.24	0.20	153.8
07-30-081-15-W-6	60.1		8.2	2.8	94.1	2.60	0.40	155.6
06-31-080-14-W-6	47.7	1.5	3.0	0.5	78.4	2.05	0.87	132.1
09-30-081-15-W-6	43.5	1.1	4.5	0.9	75.2	2.75	0.70	127.2
06-29-081-15-W-6	47.9		3.7	0.7	80.6	2.30	0.30	135.4
Minimum	37.5	1.0	2.5	0.3	68.6	0.98	0.20	113.7
Maximum	60.6	1.5	8.2	2.8	102.8	2.75	0.87	170.4
Average	48.3	1.2	4.5	1.0	83.7	1.73	0.49	139.5

Pressure Regime

Hydraulic-head values in the Kiskatinaw aquifer decrease from approximately 400 m in the south and in the northeast to less than 250 m in the central part of the Fort St. John Graben (Figure 70a), suggesting flow of formation water into this underpressured part of the graben. In comparison, hydraulic head values in the overlying Belloy aquifer decrease from more than 450 m in the northwest and south of the Bonanza Fault to less than 400 m in the east (Figure 70b), and the contour pattern suggests eastward-channelling of formation water flow between the Bonanza and Bear Canyon faults.

Plotting pressure versus elevation shows that formation pressures in the Belloy and Kiskatinaw aquifers mostly follow two distinctively different trends (Figure 71), suggesting that these aquifers are not in vertical hydraulic communication, at least within the boundaries of the Fort St. John Graben. Pressures in the Halfway-Doig aquifer follow a similar pressure-elevation trend as pressures in the underlying Belloy aquifer, not giving an indication of vertical hydraulic separation between these aquifers based on pressure data. However, salinity of formation waters is significantly less in the Halfway-Doig aquifer than in the Belloy aquifer, indicating that the Montney Formation forms an effective aquitard.

Rock Properties

The average well-scale porosity in the Kiskatinaw Formation is 8 %, and the median well-scale horizontal and vertical permeability are 22 mD and 9 mD, respectively (Table 15). The Belloy Formation is not a reservoir unit in the Pouce Coupe area and only one well with core analysis exists with porosity and permeability values below the respective average values in the Kiskatinaw Formation. Permeability values calculated for both formations at the reservoir scale from DST data range between less than 1 mD to almost 1 D, with median values of 5 mD and 2 mD in the Kiskatinaw and Belloy aquifers, respectively.

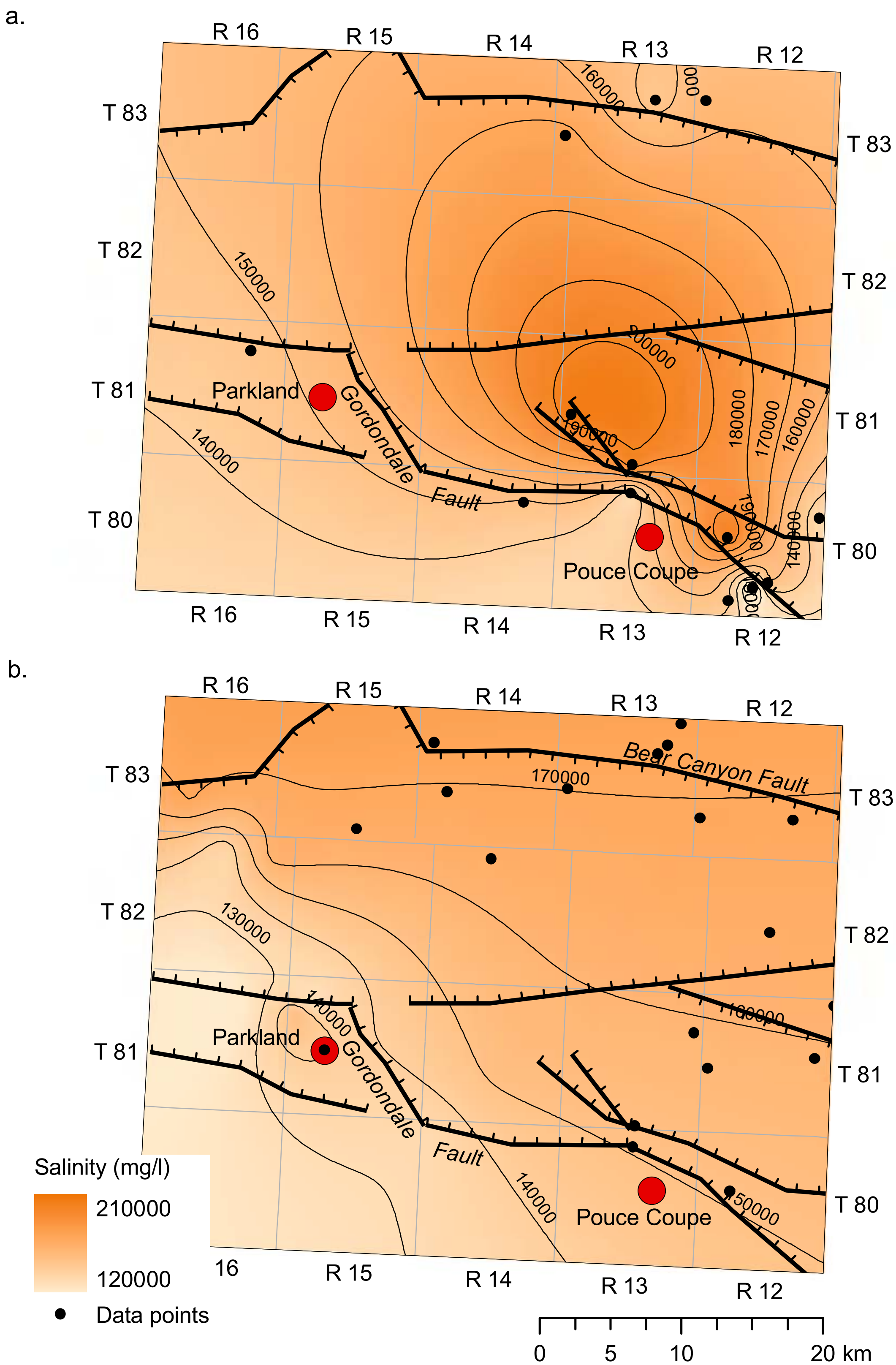


Figure 69. Distribution of salinity in the Pouce Coupe local-scale study area: a) Kiskatinaw aquifer, and b) Belloy aquifer. Injection sites are shown as red circles.

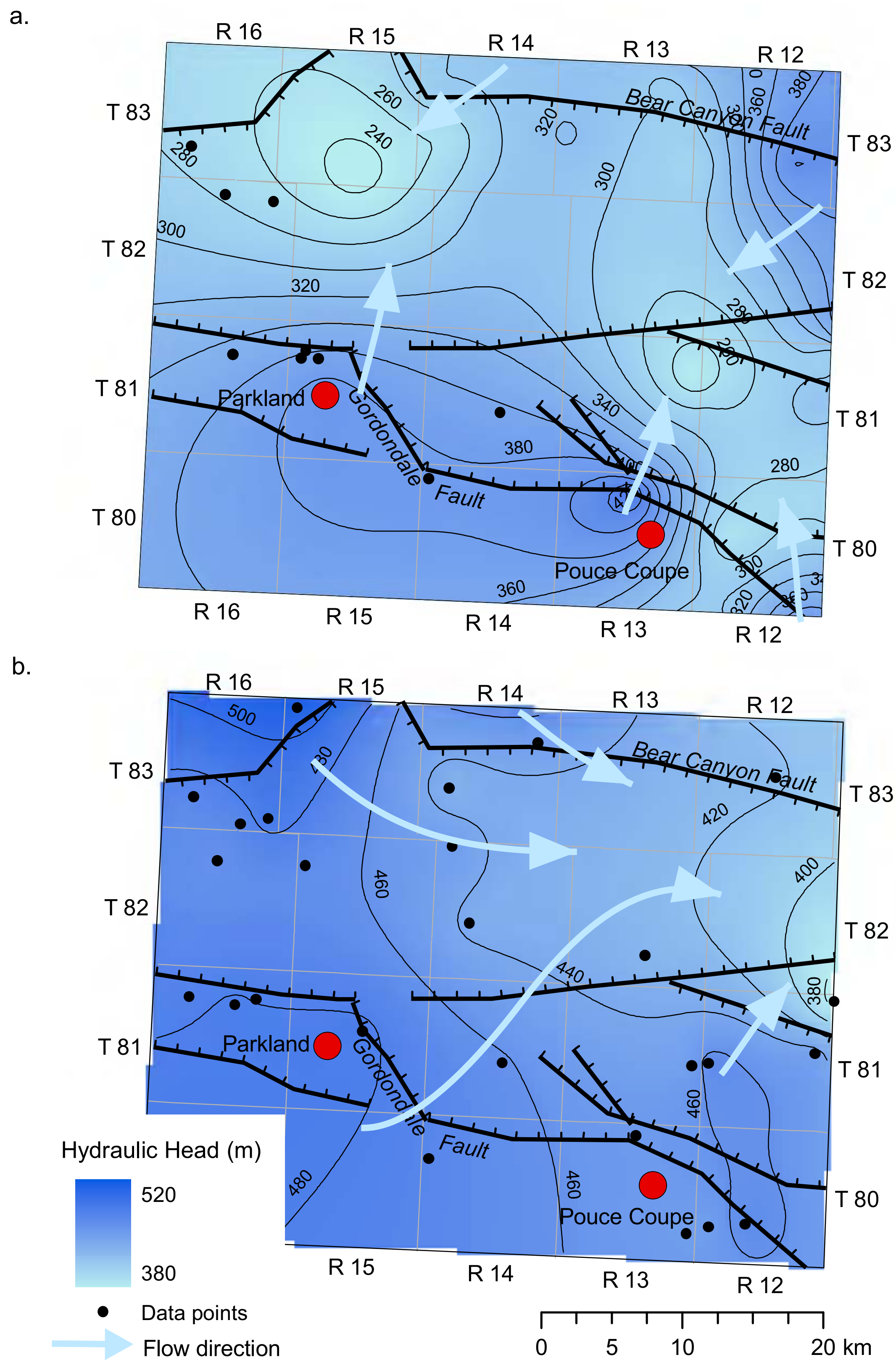


Figure 70. Distribution of hydraulic heads in the Pouce Coupe local-scale study area: a) Kiskatinaw aquifer, and b) Belloy aquifer. Injection sites are shown as red circles.

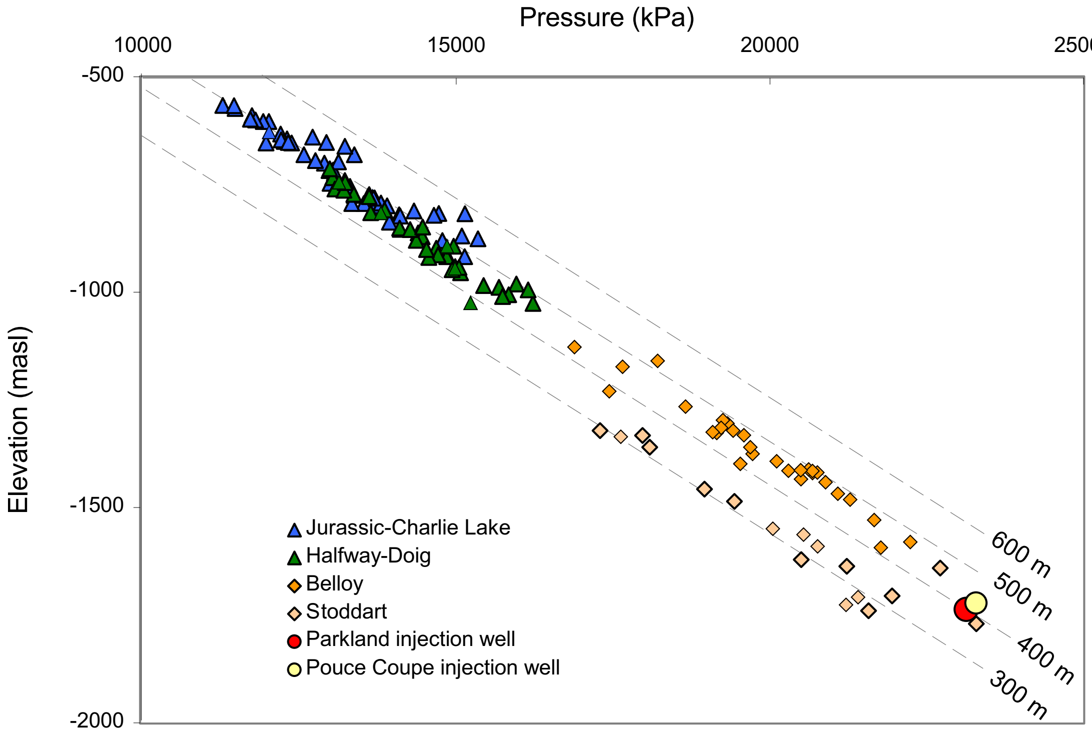


Figure 71. Distribution of pressure versus elevation in the injection strata (Kiskatinaw and Belloy formations) and adjacent formations in the Pouce Coupe area. The dashed lines delineate pressure-elevation trends with equal hydraulic-head values and the potential for vertical flow may be inferred perpendicular to those lines from high to low values.

Table 15. Well-scale porosity and permeability values obtained from measurements in core plugs from the Kiskatinaw (39 wells) and Belloy (1 well) formations in the Pouce Coupe area. Also shown are permeability values calculated from 30 drillstem test analyses performed in the Kiskatinaw aquifer and 23 DSTs from the Belloy aquifer.

	Porosity (%)			Horiz. Perm. (mD)			Vert. Perm. (mD)			DST Perm. (mD)		
Formation	Min	Max	Avg	Min	Max	Median	Min	Max	Median	Min	Max	Median
Kiskatinaw	2	18	8.2	0.04	340	22	0.02	204	9	0.3	980	5
Belloy			2.7			12				0.1	330	2

Flow of Formation Water

Flow patterns in the Belloy and Kiskatinaw aquifers are distinctively different from each other. The part of the Kiskatinaw aquifer within the Fort St. John Graben is underpressured and hydraulically isolated from the remainder of the aquifer. Lateral discontinuity of the aquifer is caused by the displacement of the Kiskatinaw Formation along the Gordondale and Bear Canyon faults, and vertical isolation from the overlying Belloy aquifer is due to the thickening of the Taylor Flat aquitard within the graben. Changes of lithofacies in the Kiskatinaw Formation from sandstone to shale result in a heterogeneous permeability distribution and add to the aquifer segregation. Areas of the Kiskatinaw aquifer with salinities up to 200 g/l, which are located in the Fort St. John Graben, suggest that these parts of the aquifer have not been diluted by mixing with fresher water from overlying formations or of meteoric origin. The overlying Belloy aquifer shows a tongue of less saline formation water in the southwest of the Pouce Coupe area (< 130 g/l). Flow of formation water is westward, in the direction of increasing salinity, which suggests that flow in the Belloy aquifer and the un-faulted part of the Kiskatinaw aquifer is driven by regional topography with recharge water in the Rocky Mountains to the southwest mixing and diluting formation water along its flow path towards the northeast. A plume of lower-salinity waters is not observed in the southeast corner of the overlying Halfway-Doig aquifer, where salinities are between 1460-180 g/l (Figure 35a). Fresher water in the Halfway-Doig aquifer appears to originate from areas of topographic highs, possibly the Clears Hills, towards the northwest of the study area, which confirms that the Montney aquitard clearly separates flow in the Halfway-Doig and Belloy aquifers.

5.6 Wembley

The Wembley local-scale study area extends from 55.20°N to 55.46°N and 118.92°W to 119.38°W (Townships 72 to 74 and Ranges 7 to 9 W6). The Wembley Field produces oil and gas from Triassic formations, while acid gas is injected into the underlying Belloy aquifer.

5.6.1 Geology

The Belloy Formation in the Wembley area consists of shelf sandstones, which form an aquifer with relatively uniform thickness of approximately 40 m (Figure 72a). The 180-220 m thick shales of the Triassic Montney Formation (Figure 72b) form an aquitard above the Belloy aquifer. Locally, a 10 m thick layer of reservoir-quality sandstones exists approximately 80 m above the base of the Montney Formation.The Belloy Formation is underlain by carbonates and anhydrites of the Taylor Flat Formation, interbedded sandstones and shales of the Kiskatinaw Formation and the Golata Formation shales (Figure 73). These three formations form the Mississippian Stoddart Group with a combined thickness of 100-150 m. While the sediments of the Taylor Flat Formation locally form seals, only the shales of the Golata Formation at the base of the Stoddart Group form a regionally extensive aquitard.

5.6.2 Hydrogeological Characteristics and Rock Properties

Very few hydrogeological data exist for the Belloy Formation in the Wembley area, because the petroleum industry has focused mainly on formations with hydrocarbon occurrences in the overlying stratigraphic succession.

Chemistry of Formation Waters

There are available only two samples of formation water from the Belloy Formation in the Wembley area. The formation water is of a Na-Cl type with 88-95 g/l chloride and 53-55 g/l sodium (Table 16). Calcium, magnesium, sulphate and bicarbonate are present in minor concentrations (Figure 74a). The brine in the Belloy aquifer has salinity between 147 and 159 g/l (Figure 75) and the average in-situ brine density is 1093 kg/m^3.

Table 16. Major ion chemistry of brines from the Belloy aquifer in the Wembley area (concentrations in g/l).

	Na	K	Ca	Mg	Cl	SO_4	HCO_3	TDS
Belloy								
14-15-074-07-W-6	53.7	1.8	2.7	1.0	88.4	1.2	1.73	147.7
11-17-073-08-W-6	55.3	2.3	2.5	1.6	94.8	1.0	1.80	159.2

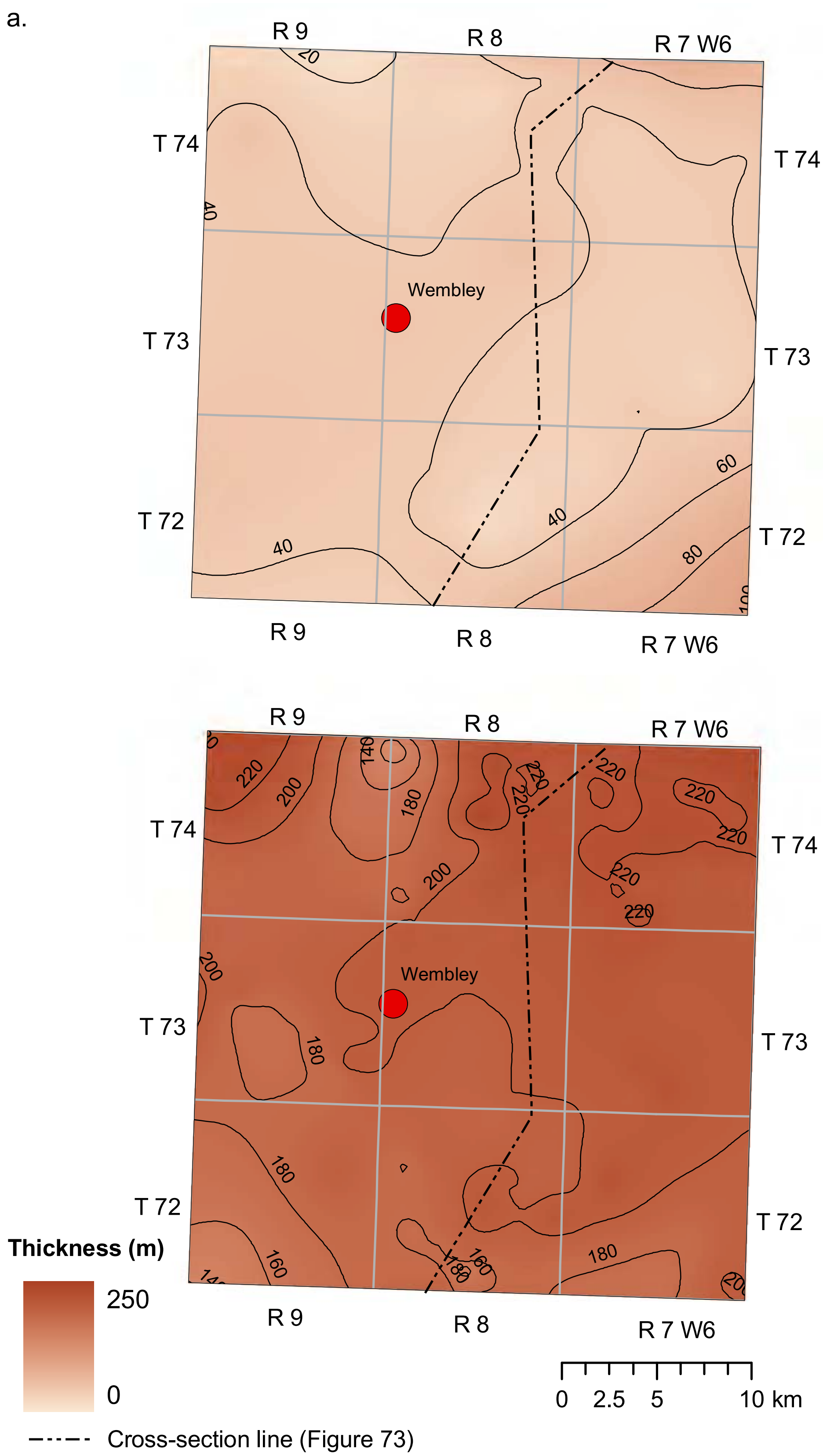


Figure 72. Isopach maps in the Wembley local-scale study area: a) Belloy Formation and b) Montney Formation. The location of the Wembley injection site is also shown.

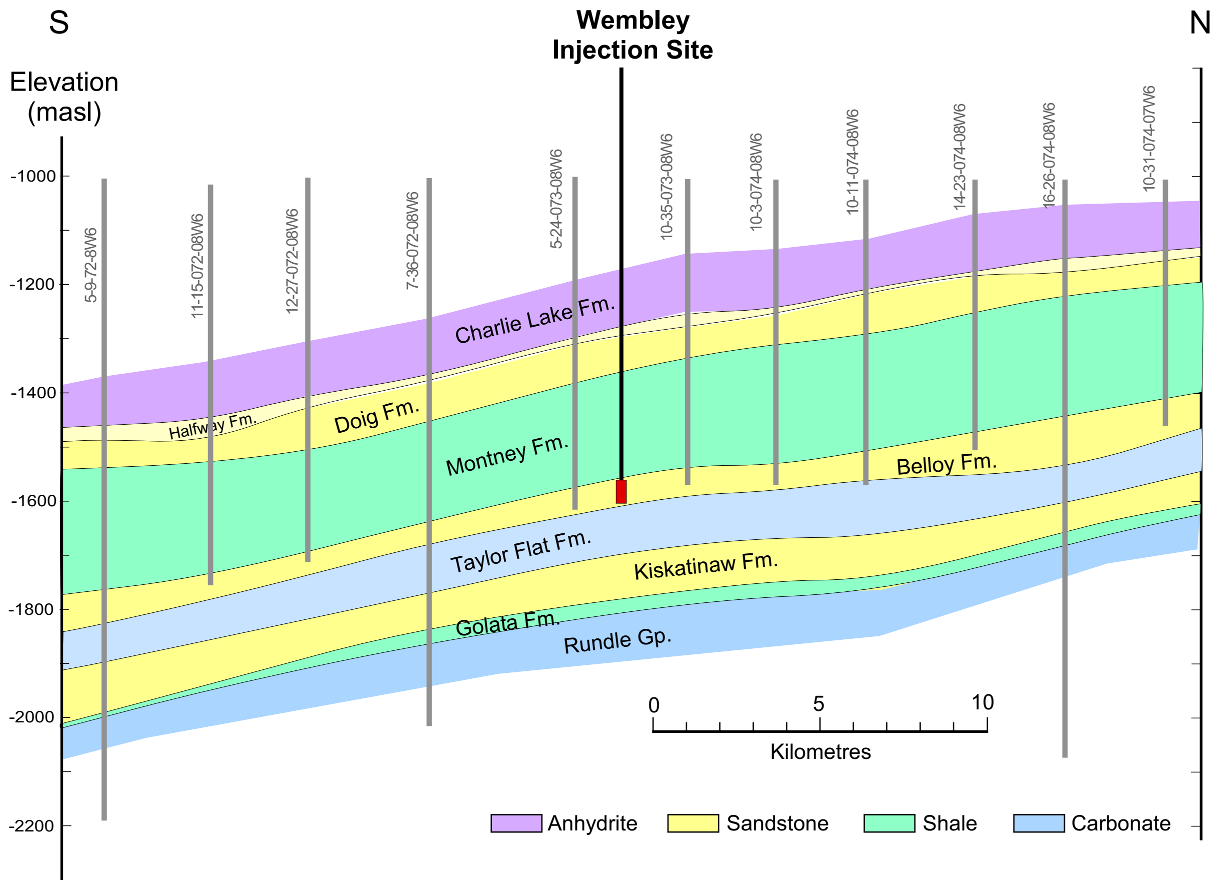


Figure 73. Local-scale structural cross-section showing the general lithology distribution from the top of the Rundle Group to the base of the Charlie Lake Formation in the Wembley area. The injection interval (red bar) is located in the Belloy Formation. the location of the line of cross-section is shown in Figure 72.

Pressure Regime

It is difficult to determine the exact flow direction of formation water from the two existing DST measurements. The general regional flow direction in the Belloy aquifer is towards the northeast (Figure 39b). However, in the Wembley area and its vicinity the regional distribution of hydraulic-head values suggest a southeastward flow direction. Plotting pressure values versus elevation (Figure 76) shows that data from the Belloy aquifer plot along a trend (~ 450 m equivalent hydraulic head) distinctly lower than data in the overlying Halfway-Doig aquifer (> 600 m equivalent hydraulic head) and Charlie Lake aquifer (> 500 m equivalent hydraulic head).This offset in pressure trends suggests that the intervening shales of the Montney Formation form an effective aquitard above the Belloy aquifer, and the potential for vertical flow is downward from the Halfway-Doig aquifer into the Belloy aquifer.

Rock Properties

The average well-scale porosity determined in two cores from the Belloy Formation is 5 %, and the median well-scale horizontal permeability is 0.5 mD (Table 17). The permeability value calculated at the reservoir scale from the analysis of one DST is 38 mD.

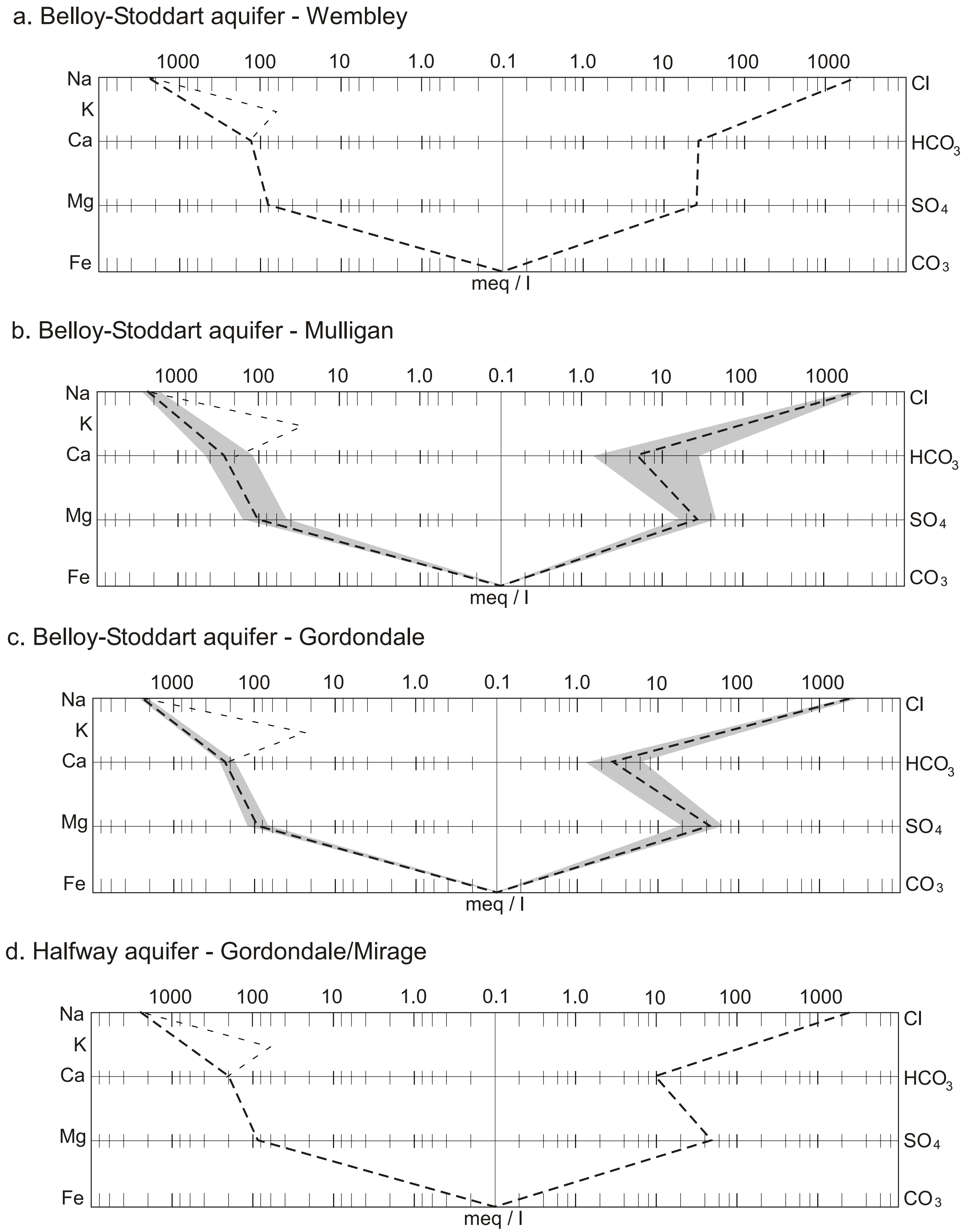


Figure 74. Stiff diagrams of formation waters from the Belloy-Stoddart and Halfway-Doig aquifers at: a) Wembley area (2 analyses), b) Mulligan area (20 analyses), c) Gordondale-Belloy (5 analyses), and d) Gordondale-Halfway (1 analysis). The grey-shaded area shows the range, the bold dashed line represents the average concentrations in meq/l (milliequilvalents per litre) and the thin dashed line represents the potassium concentration.

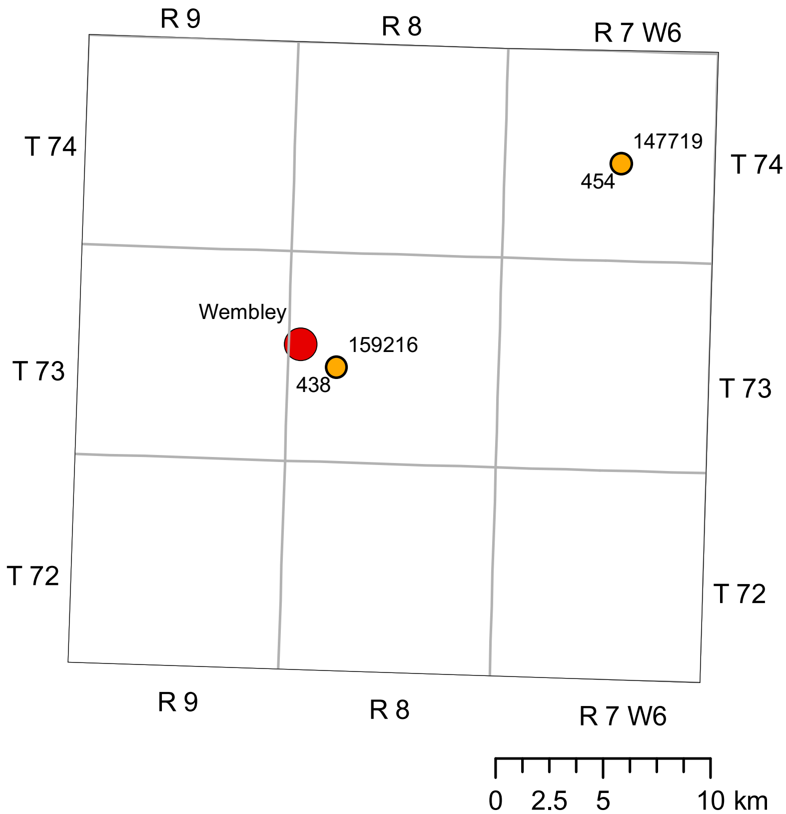


Figure 75. Distribution of salinity (upper right value) and hydraulic heads (lower left value) in the Belloy aquifer in the Wembley area. The location of the Wembley injection site is also shown.

Table 17. Well-scale porosity and permeability values obtained from measurements in core plugs in two wells from the Belloy Formation in the Wembley area. Also shown is a permeability values calculated from a single drillstem test performed in the Belloy aquifer.

	Porosity (%)			Horiz. Perm. (mD)			Vert. Perm. (mD)			DST Perm. (mD)		
Formation	Min	Max	Avg	Min	Max	Median	Min	Max	Median			
Belloy	2	8	5	0.12	1	0.51				38		

Flow of Formation Water

In the Wembley area, flow of formation water appears to be almost stagnant, however very few hydrogeological data exit to collaborate this statement. The regional distribution of hydraulic heads in the Belloy aquifer shows local irregularities in this part of the Peace River Arch area, the general flow direction being to the east – southeast. Lower salinities in the Belloy aquifer just north of the Wembley area (Figure 39b) suggest that recharge in the mountains to the west follows a regional eastward flow path, partly by-passing the Wembley area. Low aquifer thickness and possibly lower-permeability rocks due to lithofacies changes probably cause restricted flow conditions in the Belloy aquifer in the Wembley area compared to the area to the north.

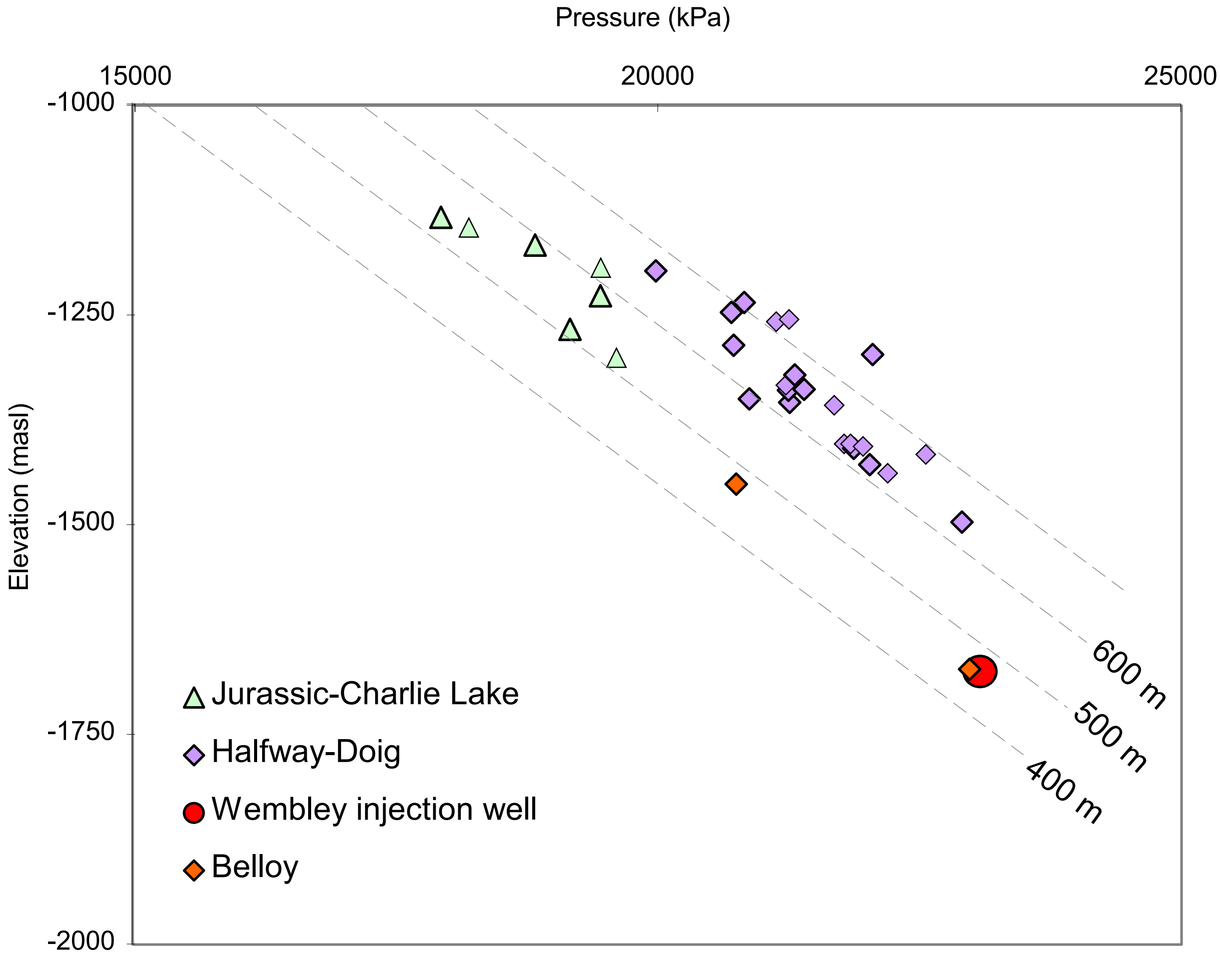


Figure 76. Distribution of pressure versus elevation in the injection strata (Belloy Formation) and adjacent formations in the Wembley area. The dashed lines delineate pressure-elevation trends with equal hydraulic-head values and the potential for vertical flow may be inferred perpendicular to those lines from high to low values.

5.7 Mulligan

The Mulligan local-scale study area extends from 55.98˚N to 56.25˚N and 118.94˚W to 119.41˚W (Townships 81 to 83 and Ranges 7 to 9W6), directly bordering the Gordondale area to the south (Figure 12). Acid gas is injected in the Permian Belloy Formation, which forms the upper part of the Belloy-Stoddart aquifer and does not contain any commercial hydrocarbon resources in the area.

5.7.1 Geology

The Belloy Formation in the Mulligan local-scale study area ranges in thickness between 50 m and 120 m (Figure 77a). At the injection site, the Belloy Formation is approximately 80 m thick with a net pay given by the operator of 25 m (based on a 12 % porosity cut-off). Within the study area, the sediments consist mainly of shallow-marine sandstone mixed with dolostone and chert.

The Belloy injection interval is overlain by more than 200 m of shale of the Triassic Montney Formation (Figure 77b), which forms an effective seal. The Belloy Formation is underlain by carbonates and

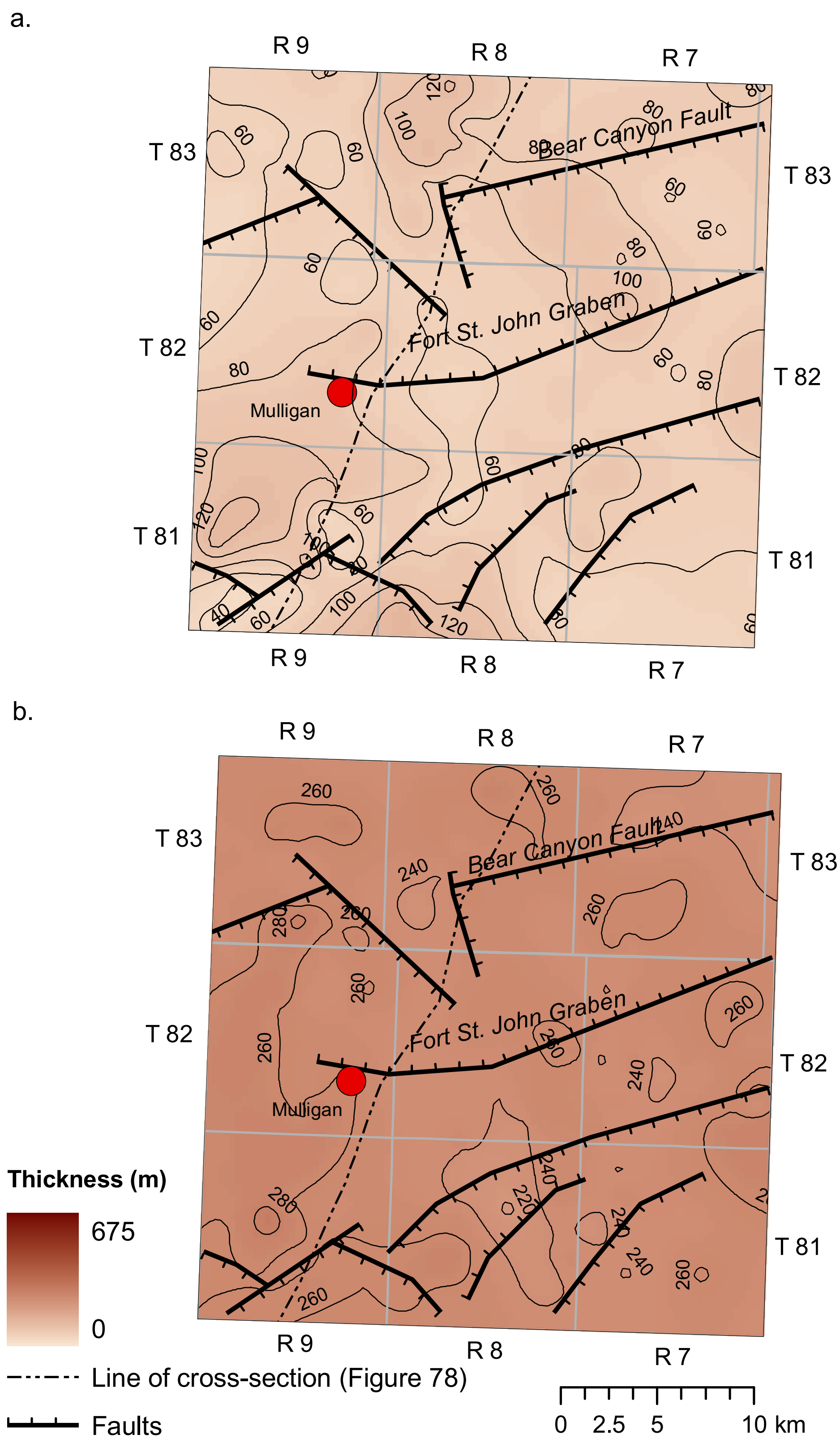


Figure 77. Isopach maps in the Mulligan local-scale study area: a) Belloy Formation and b) Montney Formation. The location of the Mulligan injection site is also shown.

anhydrites of the Taylor Flat Formation, interbedded sandstones and shales of the Kiskatinaw Formation and the Golata Formation shales (Figure 78). These three formations form the Mississippian Stoddart Group with a combined thickness increasing from 50 m in the northeast to more than 400 m in the southwest. While the sediments of the Taylor Flat Formation locally form seals, only the shales of the Golata Formation at the base of the Stoddart Group form a regionally extensive aquitard.

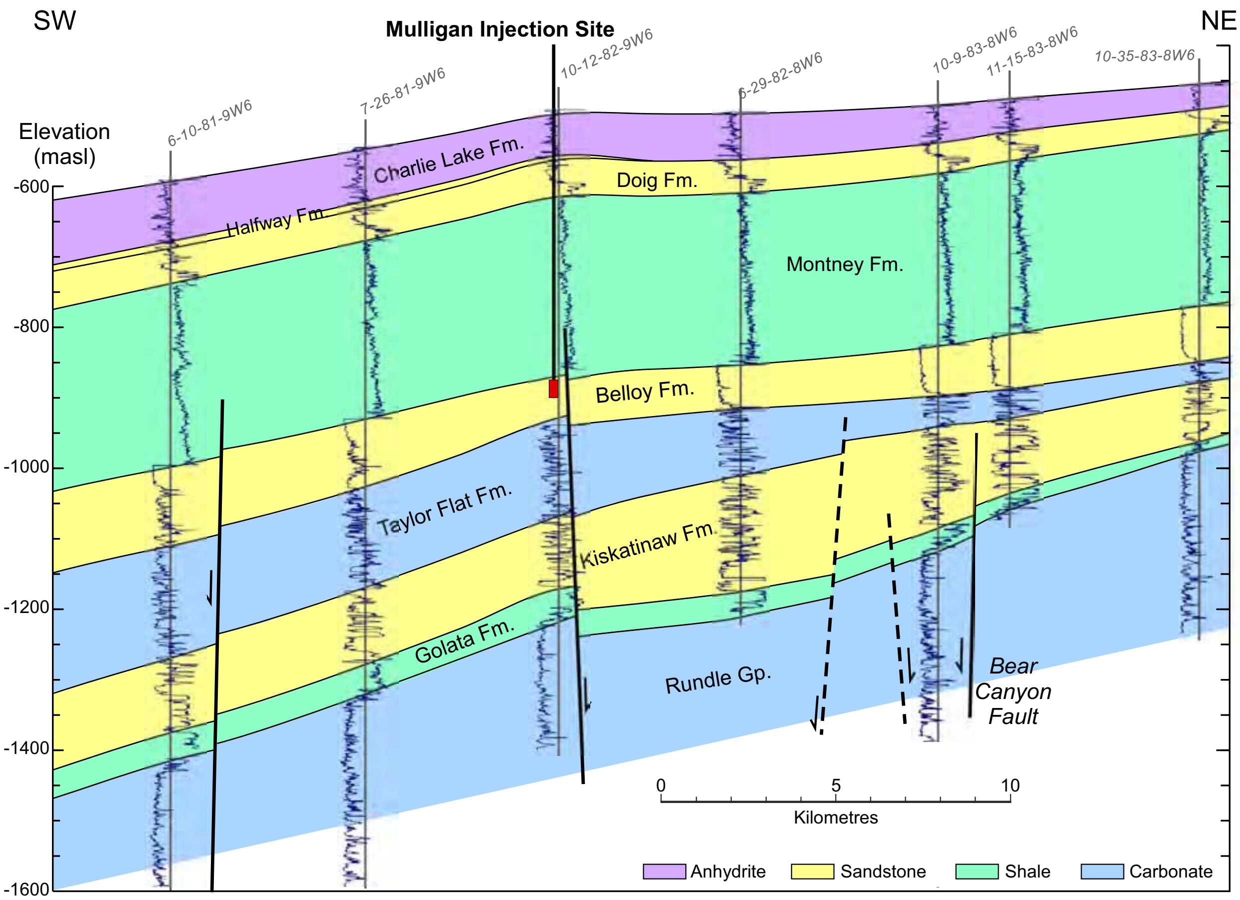


Figure 78. Local-scale structural cross-section showing the general lithology distribution from the top of the Rundle Group to the base of the Charlie Lake Formation in the Mulligan area. The injection interval (red bar) is located in the Belloy Formation. The gamma-ray logs show the intra-formational lithofacies heterogeneity, particularly in the Taylor Flat and Kiskatinaw formations and in the southwest of the Belloy Formation. The location of the line of cross-section is shown in Figure 77.

Structurally, the Mulligan area lies within the eastern part of the Fort St. John Graben, where the main graben branches off into the Hines Creek Graben (Figure 15). The Carboniferous to Permian strata in the Mulligan area are subdivided into internal horsts and grabens by various SW-NE trending normal faults (Figure 77). Only in the southwestern corner a set of WNW-ESE trending normal faults follow the main regional trend of the Fort St. John Graben towards the east-southeast. The syn-sedimentary character of the faulting is expressed by the increasing thickness of the Stoddart Group sediments towards the graben center in the south-southwest, which make up the majority of the graben fill (Figure 78). The injection site is located on the northeastern flank of an internal horst structure within the Fort St. John Graben.

5.7.2 Hydrogeological Characteristics and Rock Properties

Although, the succession from the Belloy to the Kiskatinaw Formation forms the contiguous Belloy-Stoddart aquifer on a regional scale, thickening of tight carbonates in the Taylor Flat Formation, especially within grabens locally form an aquitard between the Belloy and Kiskatinaw formations.

Chemistry of Formation Waters

Formation water in the Belloy and Kiskatinaw aquifers in the Mulligan area is of a Na-Cl type, with an average of 55.3 g/l sodium and 127.0 g/l chloride (Table 18). Calcium, magnesium, sulphate and bicarbonate are present in minor concentrations (Figure 74b). There is no distinct difference in formation water chemistry between the Belloy and Kiskatinaw formations. The salinity of Belloy-Stoddart formation water decreases slightly from approximately 175 g/l in the southwest to 125 g/l in the northeast, in the centre of the graben (Figure 79a). The average in-situ brine density in the Mulligan area was calculated to be 1108 kg/m^3.

Table 18. Major ion chemistry of brines from the Belloy-Stoddart aquifer in the Mulligan area (concentrations in g/l).

	Na	K	Ca	Mg	Cl	SO_4	HCO_3	TDS
Belloy								
10-17-082-07-W-6	54.7		4.1	1.0	93.0	1.73	0.48	154.8
10-17-082-07-W-6	53.5	1.0	4.3	0.9	91.2	1.83	0.14	151.9
08-31-083-07-W-6	55.9	1.1	3.7	0.8	93.8	1.48	0.24	155.7
01-16-082-07-W-6	54.9	0.9	3.7	0.8	92.3	1.37	0.50	153.3
Kiskatinaw								
06-10-083-09-W-6	55.8	0.6	8.1	1.1	102.5	1.35	0.15	169.2
11-21-081-08-W-6	57.0		8.1	1.8	106.0	1.75	0.23	174.7
06-12-081-09-W-6	57.3	0.6	8.7	1.1	106.0	1.13	0.11	174.5
06-30-083-06-W-6	60.1		4.6	0.9	86.0	2.00	0.17	143.4
06-29-081-07-W-6	54.5		8.0	1.7	102.2	1.14	0.23	167.6
07-20-083-08-W-6	55.7		5.2	1.1	97.0	1.45	0.30	160.6
08-05-083-07-W-6	45.6	0.5	2.6	0.6	75.0	1.95	0.34	125.9
10-17-082-07-W-6	56.3		5.6	1.8	101.0	1.22	0.15	166.0
06-21-083-08-W-6	56.4		6.8	1.8	103.5	0.84	0.20	169.5
13-35-083-09-W-6	56.4		5.8	1.1	99.4	1.21	0.44	164.2
06-36-081-07-W-6	52.6	0.7	6.1	1.6	94.0	1.90	1.88	157.1
06-23-081-09-W-6	57.9	0.2	7.8	1.0	104.5	1.65	0.24	172.9
06-23-081-09-W-6	68.4	0.3	9.0	2.2	127.0	1.02	0.10	207.7
08-21-083-07-W-6	53.6	0.7	3.2	1.2	90.0	2.14	0.09	150.1
11-09-082-08-W-6	55.8		6.6	1.8	102.2	1.15	0.17	167.7
10-23-083-09-W-6	54.8		7.4	1.4	100.8	0.88	0.16	165.3
Minimum	45.6	0.2	2.6	0.6	75.0	0.84	0.09	125.9
Maximum	68.4	1.1	9.0	2.2	127.0	2.14	1.88	207.7
Average	55.3	0.7	6.0	1.3	98.4	1.46	0.32	162.6

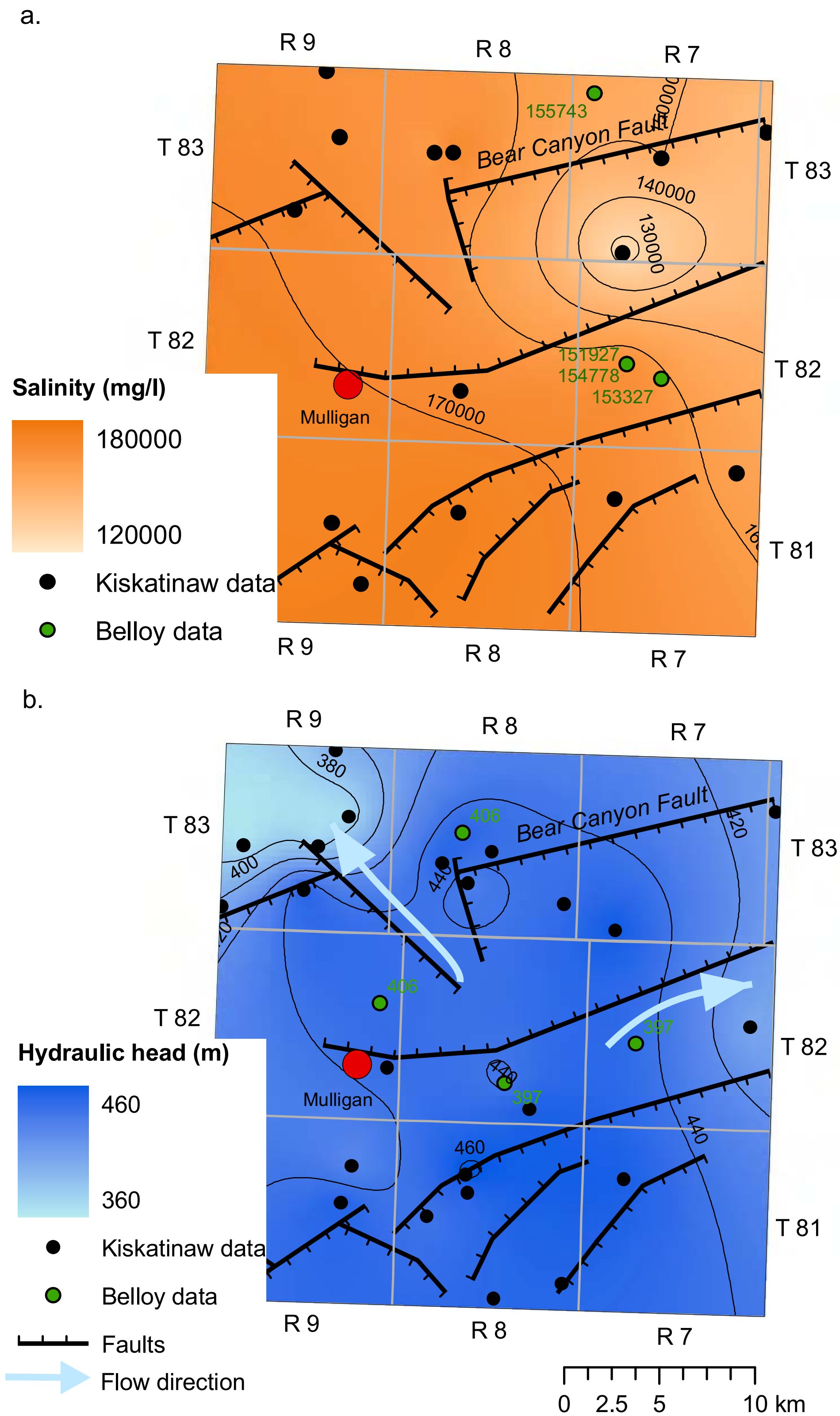


Figure 79. Distribution of a) salinity and b) hydraulic heads in the Belloy aquifer (green data points) and in the Kiskatinaw aquifer (gridded data) in the Mulligan area. The location of the Mulligan injection site is also shown.

Pressure Regime

Only four DSTs were performed in the Belloy Formation in the Mulligan area, all showing a hydraulic head value of approximately 400 m (Figure 79b). The regional distribution of hydraulic-heads suggests a northeastward flow direction of formation water in the Belloy Formation with very low hydraulic gradients. Hydraulic head values in the underlying Kiskatinaw Formation decrease from above 450 m in the south to less than 400 m in the northwest and northeast corners of the study area, respectively, indicating northwestward and northeastward flow of formation water. High hydraulic gradients across the Bear Canyon Fault in the northwest suggest that the offset of the Kiskatinaw Formation along the fault results in a barrier to lateral fluid flow. Within the graben center and specifically at the injection site, hydraulic heads in the Kiskatinaw Formation (~ 440 m) are higher than those in the Belloy Formation (Figure 79b), confirming that the intervening Taylor Flat Formation forms a local aquitard in this part of the graben. On the other hand, at the northeast end of the graben and northwest of the Bear Canyon Fault, the Belloy and Kiskatinaw formations appear to be in direct hydraulic communication as indicated by similar hydraulic head values in both formations.

Plotting pressure versus elevation also shows two trends (Figure 80): formation pressure in the Kiskatinaw Formation within the graben (equivalent to approximately 450 m hydraulic head) versus pressure data in the Belloy Formation combined with pressures in the shallower parts of the Kiskatinaw Formation (equivalent to approximately 400 m hydraulic head). In contrast, pressure data in the overlying Triassic aquifers plot along a trend equivalent to 500 m hydraulic head, which suggests that the intervening shales of the Montney Formation form an effective aquitard and that the potential for vertical flow is downwards into the Belloy-Stoddart aquifer.

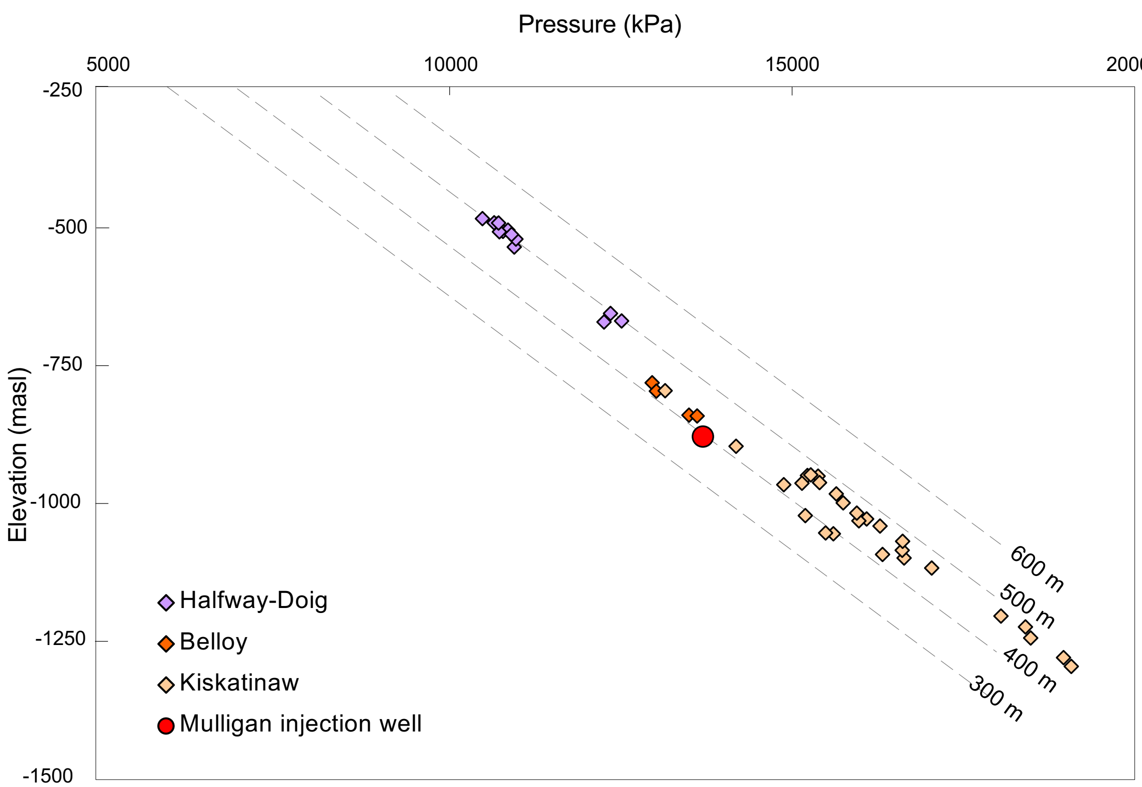


Figure 80. Distribution of pressure versus elevation in the injection strata (Belloy Formation) and adjacent formations in the Wembley area. The dashed lines delineate pressure-elevation trends with equal hydraulic-head values and the potential for vertical flow may be inferred perpendicular to those lines from high to low values.

Rock Properties

The range and average of well-scale porosity and permeability values for the injection horizon, the Belloy Formation, and the underlying Kiskatinaw Formation are shown in Table 19. Only one core sample analysis from the Belloy Formation is available in the Mulligan area with 15 % porosity, a horizontal permeability of 6 mD and a vertical permeability of 2 mD. The Kiskatinaw Formation has an average porosity of 9 %, 22 mD horizontal permeability and 12 mD vertical permeability. Also shown are reservoir-scale permeability values calculated from drillstem tests that were performed in the Belloy and Kiskatinaw aquifers. These values are of the same order of magnitude as the horizontal permeability averaged for the core analyses with a median permeability of 11 mD and 8 mD for the Belloy and Kiskatinaw formations, respectively.

Table 19.Well-scale porosity and permeability values obtained from measurements in core plugs from the Kiskatinaw (20 wells) and Belloy (1 well) formations in the Mulligan area. Also shown are permeability values calculated from drillstem test analyses performed in the Belloy (3 tests) and Kiskatinaw (30 tests) formations.

.	Porosity (%)			Horiz. Perm. (mD)			Vert. Perm. (mD)			DST Perm. (mD)		
Formation	Min	Max	Avg	Min	Max	Median	Min	Max	Median	Min	Max	Median
Belloy			15			6			2	9	113	11
Kiskatinaw	4	15	9	0.05	217	22	0.01	73	12	0.11	292	8

Flow of Formation Water

The majority of hydrogeological data in the Mulligan area is from the Stoddart Group, which is the main target for hydrocarbon production, and data from the injection target, the Belloy Formation is limited. While in the eastern part of the Peace River Arch area, the Belloy and Kiskatinaw formations form a contiguous aquifer, the presence of a thick Taylor Flat Formation, particularly in the southwest of the Mulligan area, results in a vertical hydrostratigraphic separation into the Belloy and Kiskatinaw aquifers. Flow of formation water in the Belloy aquifer appears to be almost stagnant, although the regional hydraulic-head pattern suggests flow towards the northeast with a hydraulic gradient of approximately 0.7 m/km. The Montney Formation forms an effective aquitard, overlying the injection zone.Formation water flow in the underlying Kiskatinaw aquifer in the Mulligan area seems to be restricted, both laterally and vertically, resulting in a hydraulic-head high in the centre of the study area. Faults, particularly the Bear Canyon Fault in the north, constrain the lateral flow, whereas the increased thickness of the low-permeability Taylor Flat Formation prevents cross-formational flow in most of the area. Only in the northeast and northwest corners, flow of formation water in the Kiskatinaw aquifer merges with flow in the Belloy aquifer.

5.8 Gordondale

The Gordondale local-scale study area extends from 55.77˚N to 55.99˚N and 118.93˚W to 119.47˚W (Townships 78 (northern half) to 80 and Ranges 7 to 10 (eastern half) W6), directly bordering the Mulligan area to the north (Figure 12). Two acid-gas injection operations are located in this area. At the Gordondale site, acid gas was injected initially into the Triassic Halfway Formation. However, the operator switched to disposal into the Belloy Formation, abandoning the former injection unit. The second operation is Mirage, where acid-gas was injected into the Halfway Formation, and which was rescinded in 1995.

5.8.1 Geology

Within the Gordondale local-scale study area, the Belloy Formation can be subdivided into an upper, clean shallow-marine sandstone, which forms the aquifer and a cherty, dolomitic limestone at the base. The Belloy aquifer ranges in thickness between 35 m and 85 m (Figure 81a). Gamma-ray logs signatures indicate that, at the injection site, the sandy, permeable part of the Belloy Formation is approximately 50 m thick (Figure 82) with a net pay given by the operator of 13 m (based on a 12 % porosity cut-off).

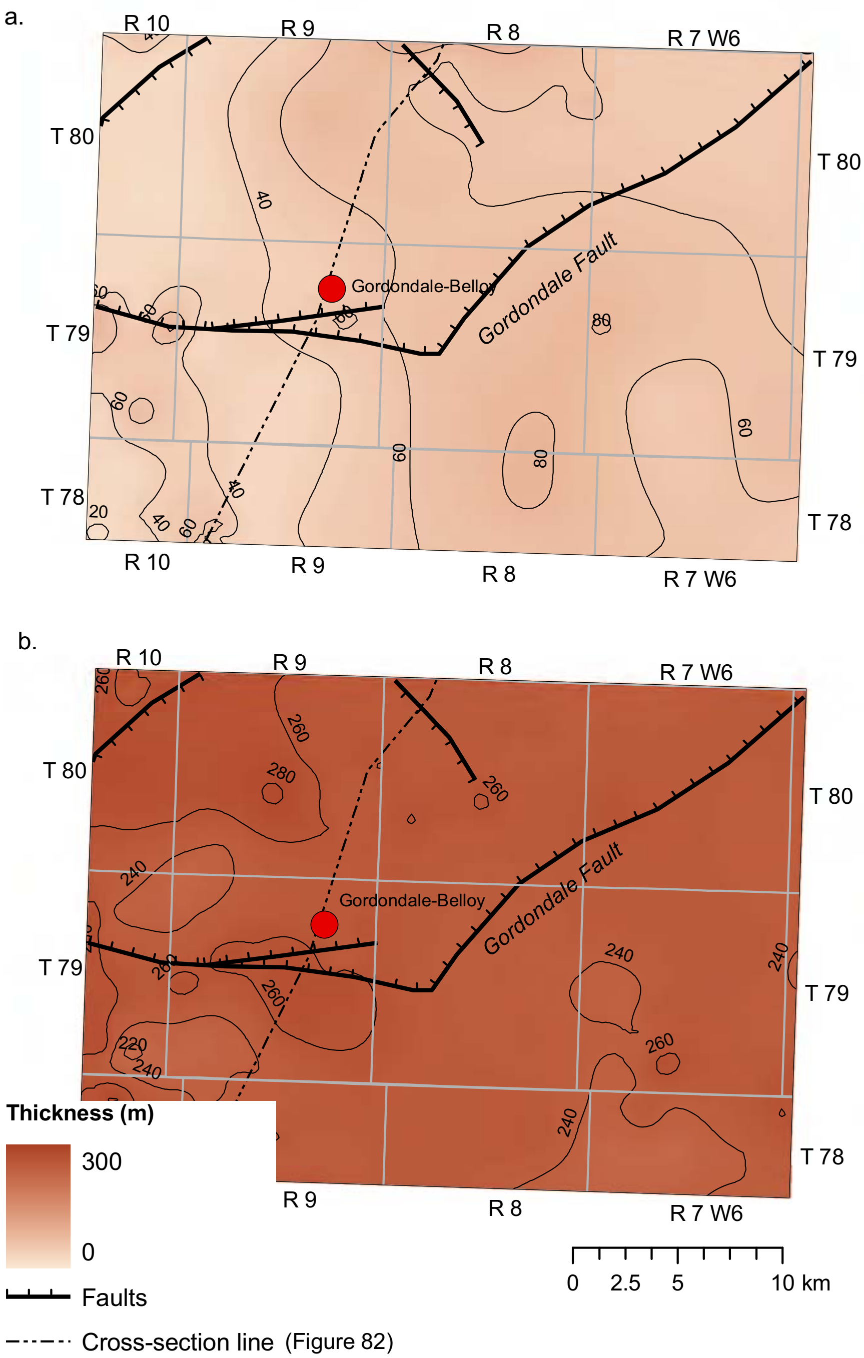


Figure 81. Isopach maps in the Gordondale local-scale study area: a) Belloy aquifer (upper part of the Belloy Formation) and b) Montney Formation. The location of the Gordondale injection site is also shown.

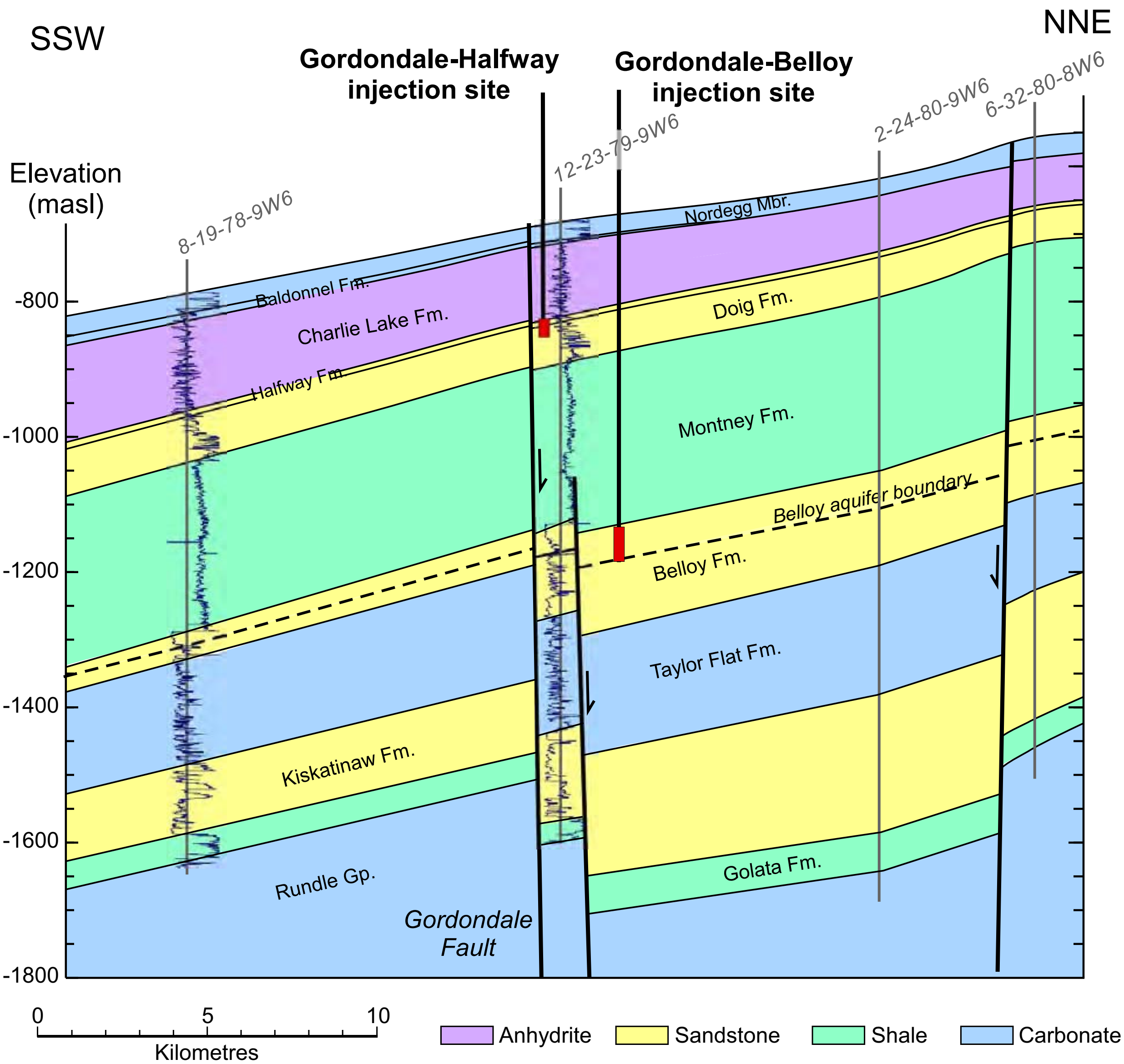


Figure 82. Local-scale structural cross-section showing the general lithology distribution from the top of the Rundle Group to the base of the Jurassic Nordegg Member in the Gordondale area. The injection intervals (red bar) are located in the Belloy and Halfway formations. The location of the line of cross-section is shown in Figure 81.

The Belloy injection interval is overlain by more than 220 m to 270 m of shale of the Triassic Montney Formation (Figure 81b), which forms an effective seal. The Belloy Formation is underlain by carbonates and anhydrites of the Taylor Flat Formation, interbedded sandstones and shales of the Kiskatinaw Formation and the Golata Formation shales (Figure 82). These three formations form the Mississippian Stoddart Group with a combined thickness decreasing from 50 m in the northeast to more than 400 m in the southwest. While the sediments of the Taylor Flat Formation locally form seals, only the shales of the Golata Formation at the base of the Stoddart Group form a regionally extensive aquitard.

Structurally, the Gordondale area lies within the eastern part of the Fort St. John Graben, at its southern flank. The main structural feature is the Gordondale Fault, which changes from a W-E strike direction in the west to a SW-NE strike direction in the eastern half of the study area (Figure 81). The syn-sedimentary character of the faulting is expressed by the increasing sediment thickness of the Stoddart Group and the Belloy Formation towards the graben center in the south-southwest, which make up the majority of the graben fill. On the other hand, the upper part of the Belloy Formation that forms the aquifer was deposited towards the end of graben subsidence, resulting in a more uniform aquifer isopach. The Gordondale injection site is located just north of the Gordondale Fault, within the down-faulted graben (Figure 82). A subtle inflection in the structure top of the Triassic Formations suggests that the Gordondale Fault might have been re-activated in the Jurassic or in the Cretaceous; however there is no evidence for offsets in the various Triassic formation surfaces.

The Triassic Halfway Formation is the second injection target in the Gordondale area. The Halfway Formation is formed by up to 25 m thick sandstones (Figure 83a) that were deposited in a shallow to marginal marine environment (Gibson and Edwards, 1990). These sandstones show various types of lamination and generally have well-developed intergranular porosity (Figure 84) The Halfway Formation attains maximum thickness along NW-SE-trending sandbars, which often form hydrocarbon reservoirs, as it is the case for the Mirage, Gordondale, and Progress oil pools (Figure 83a). Generally, the lateral extent of the pools is limited by a thinning of the sandstone bodies due to a facies change to siltstones and shales. The Halfway Formation is overlain by 40 to 150 m thick anhydrites of the Charlie Lake Formation (Figure 83b). A mixture of shale, siltstone and sandstone of the Doig Formation up to 50 m thick underlies the Halfway Formation and locally forms the bottom seal. However, local channel-sandstones exist in the Doig Formation, which for example host a gas pool at Progress, and on a regional scale, the Halfway and Doig formations form the Halfway-Doig aquifer. Eventually, the more than 200 m thick Montney shales form the bottom seal to the Halfway-Doig succession (Figures 82 and 85).

5.8.2 Hydrogeological Characteristics and Rock Properties

Although the succession from the Belloy to the Kiskatinaw Formation forms the contiguous Belloy-Stoddart aquifer on a regional scale, thickening of tight carbonates in the Taylor Flat Formation, especially within grabens locally form an aquitard between the Belloy and Kiskatinaw formations.

Chemistry of Formation Waters

Only one sample of formation water is available from the Belloy Formation in the Gordondale area. An additional four samples with similar characteristics were taken from the underlying Stoddart Group. The formation water of the Belloy-Stoddart aquifer is of a Na-Cl type similar to the brine in the Mulligan area, with an average of 51.2 g/l sodium and 90.0 g/l chloride (Table 20). Calcium, magnesium, sulphate and bicarbonate are present in minor concentrations (Figure 74c). There is no distinct difference in formation water chemistry between the Belloy Formation and the Stoddart Group. The salinity of Belloy-Stoddart formation water ranges from approximately 134 g/l to 167 g/l without any clear trend (Figure 86a). The average in-situ brine density in the Gordondale area was calculated to be 1094 kg/m^3.

Only one formation water samples exist for the Halfway Formation. The salinity of the Na-Cl type water is 170 g/l, and it decreases northeastward, following the regional salinity trend (Figure 35a).

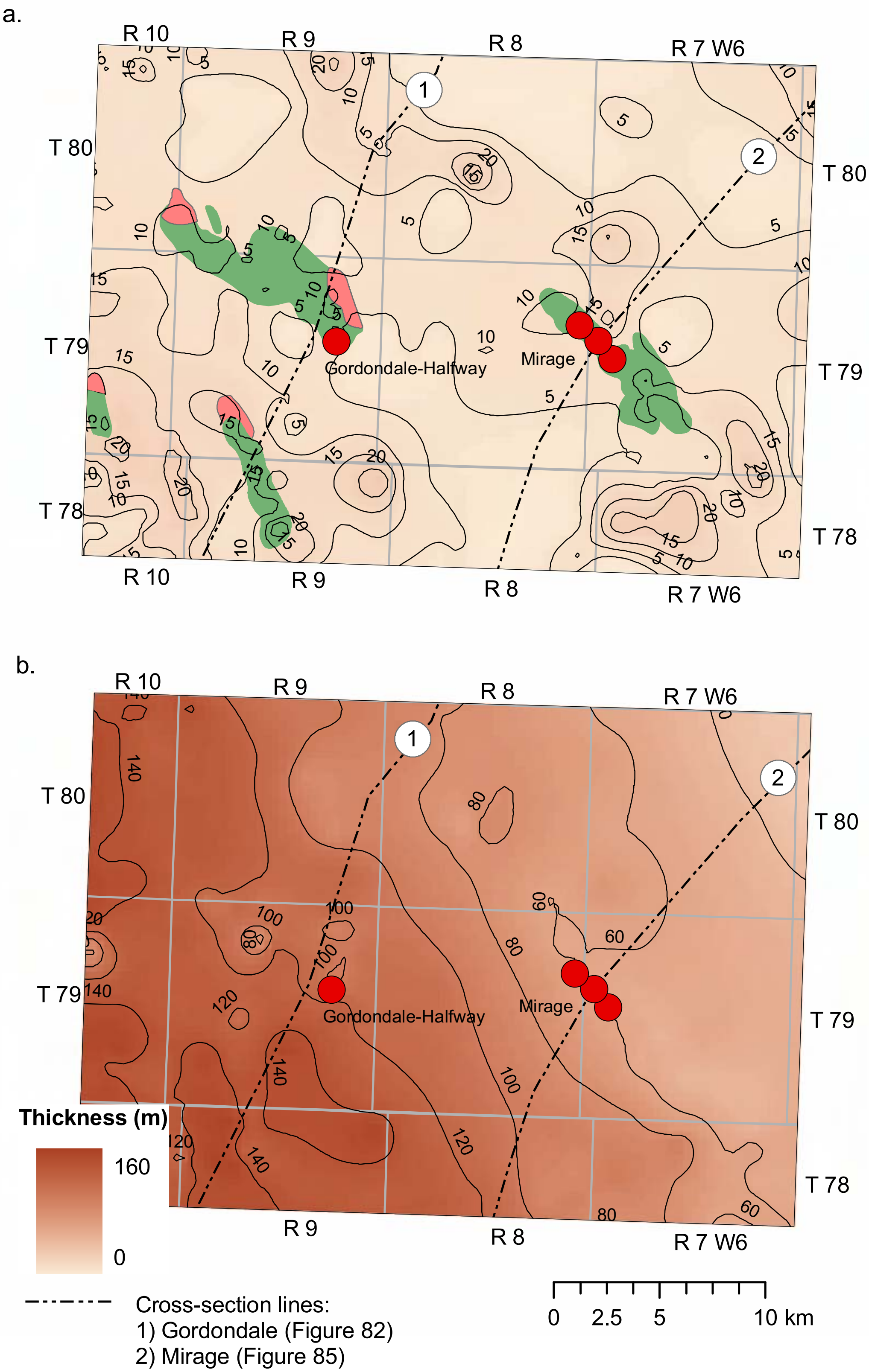


Figure 83. Isopach maps in the Gordondale local-scale study area: a) Halfway Formation and b) Charlie Lake Formation. The location of the Gordondale and Mirage injection sites and the outline of Halfway oil pools (green) and gas pools (red) are also shown.

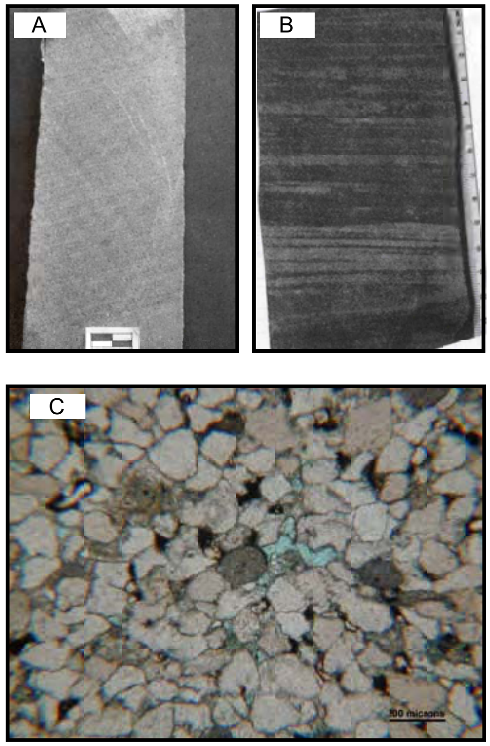


Figure 84. Core and thin section photographs of the Halfway Formation sandstone. Cross-laminated sandstones (Photo A; from Norgard, 1997) change to flat planar-laminated sandstone (Photo B; from Young, 1997), which consist mainly of quartz. The inter-granular porosity can best be seen on the blue stained pores in the center of the thin section photo (Photo C).

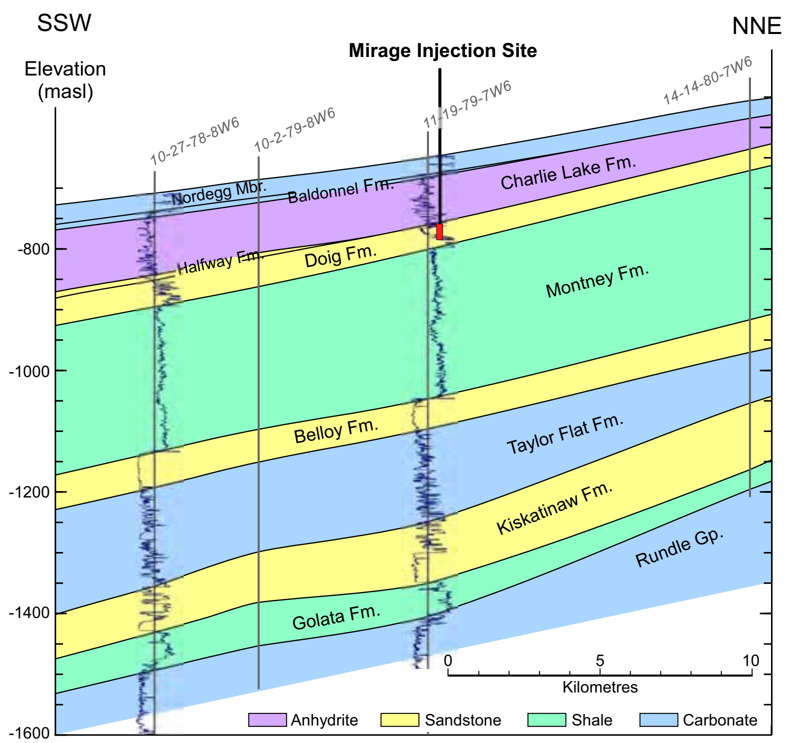


Figure 85. Local-scale structural cross-section showing the general lithology distribution from the top of the Rundle Group to the Nordegg Member in the Gordondale area. The injection interval (red bar) is located in the Halfway Formation. The location of the line of cross-section is shown in Figure 83.

Table 20. Major ion chemistry of brines from the Belloy-Stoddart and Halfway aquifers in the Gordondale area (concentrations in g/l). * indicates analysis from the acid-gas injection well.

	Na	K	Ca	Mg	Cl	SO_4	HCO_3	TDS
Stoddart								
07-10-080-07-W-6	56.8	0.5	5.8	1.5	100.9	1.75	0.08	167.1
11-19-079-07-W-6	45.6	0.4	4.9	1.0	79.6	2.75	0.15	134.0
14-14-080-07-W-6	47.9	0.6	3.8	0.9	80.8	2.95	0.19	136.4
15-23-079-10-W-6	52.4	1.4	3.8	1.1	90.0	0.92	0.40	148.5
Belloy								
10-26-079-09-W-6*	53.4	1.8	4.8	1.0	98.8	0.80	0.47	162.0
Minimum	45.6	0.4	3.8	0.9	79.6	0.80	0.08	134.0
Maximum	56.8	1.8	5.8	1.5	100.9	2.95	0.47	167.1
Average	51.2	0.9	4.6	1.1	90.0	1.83	0.26	149.6
Halfway								
14-13-080-09-W-6	57.1	2.4	7.2	1.3	103.5	0.82	0.49	170.0

Pressure Regime

Only two qualitatively viable DSTs were performed in the Belloy Formation in the Gordondale area. Also, the small hydraulic gradient, as indicated by the difference in hydraulic-head values (433 m and 440) (Figure 86a), makes it difficult to identify an exact flow direction of formation water in the area. The regional distribution of hydraulic heads suggests a general northward flow direction, formation water entering the Gordondale area from the south, then following the course of the graben towards the northeast, north of the Gordondale fault.

Hydraulic-head values in the Halfway aquifer decrease from above 600 m in the southwest to approximately 450 m in the east (Figure 86b), suggesting northeast- to eastward flow of formation water. An abrupt decrease in hydraulic-head values from 575 m to 500 m corresponds to a relatively high hydraulic gradient. This hydraulic gradient could have been induced by either a change in aquifer permeability or transmissivity or sealing faults, obstructing lateral flow between the western and eastern parts of the study area.

Plotting pressure versus elevation (Figure 87) shows that formation pressure in the Belloy Formation and Stoddart Group follow a similar trend (equivalent to approximately 450 m hydraulic head), and there is no indication that the Taylor Flat Formation prevents hydraulic communication between the Belloy and Kiskatinaw aquifers. In contrast, pressure data in the overlying Triassic aquifers plot along a trend equivalent to 500 m hydraulic head and higher, which suggests that the intervening shales of the Montney Formation form an effective aquitard and that the potential for vertical flow is downwards into the Belloy-Stoddart aquifer. A lateral subdivision of the Halfway aquifer is expressed by the offset of pressure data that plot above the 500 m contour line in and data from shallower part of the aquifer with equivalent hydraulic-head values below 500 m (Figure 87). At Gordondale, acid-gas is injected into an overpressured reservoir within the Halfway-Doig aquifer, whereas at Mirage injection occurs into a normally-pressured reservoir.

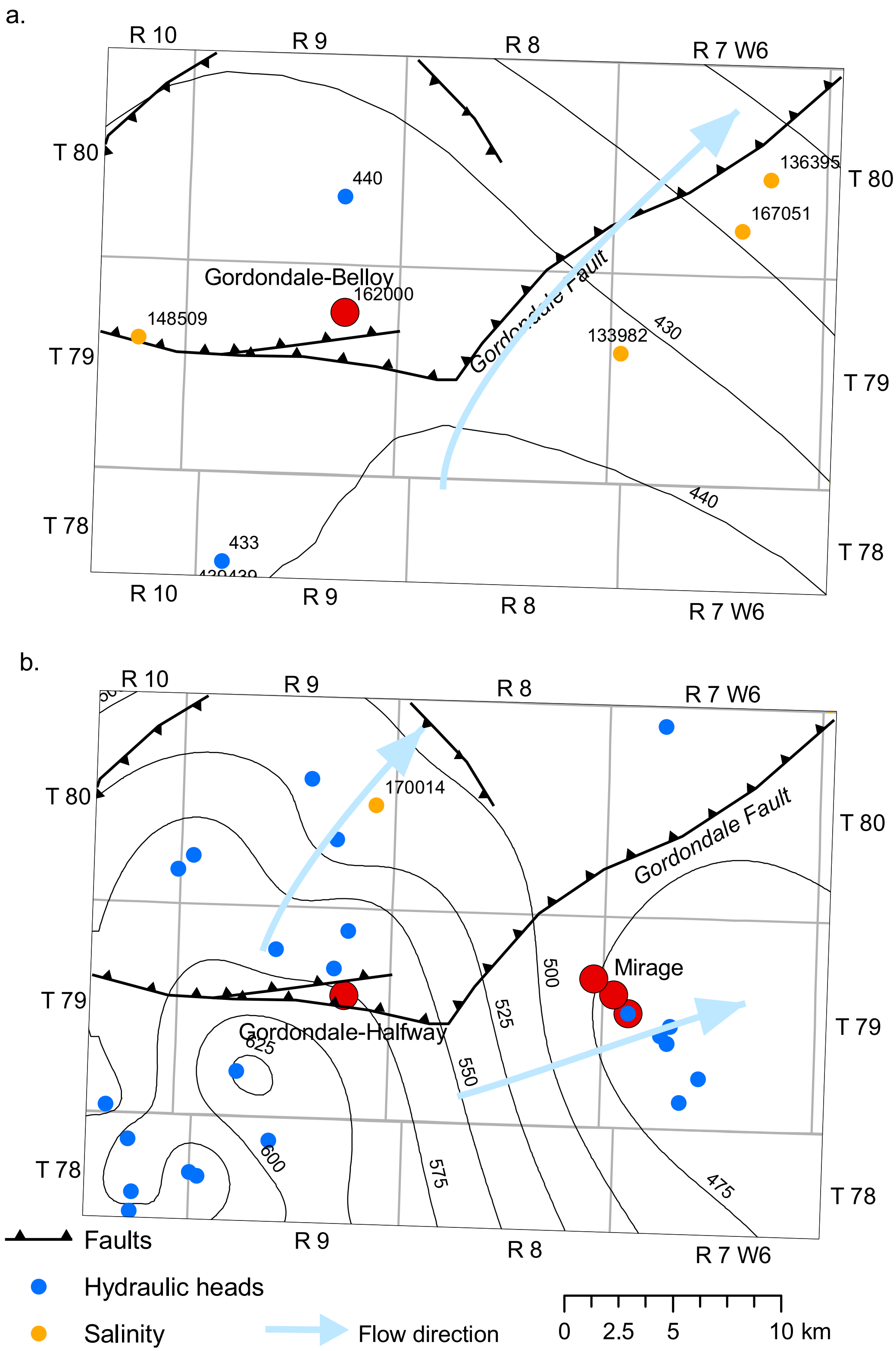


Figure 86. Distribution of salinity and hydraulic-head contours in the a) Belloy aquifer and b) Halfway-Doig aquifer in the Gordondale area. The locations of the Gordondale and Mirage injection sites are also shown.

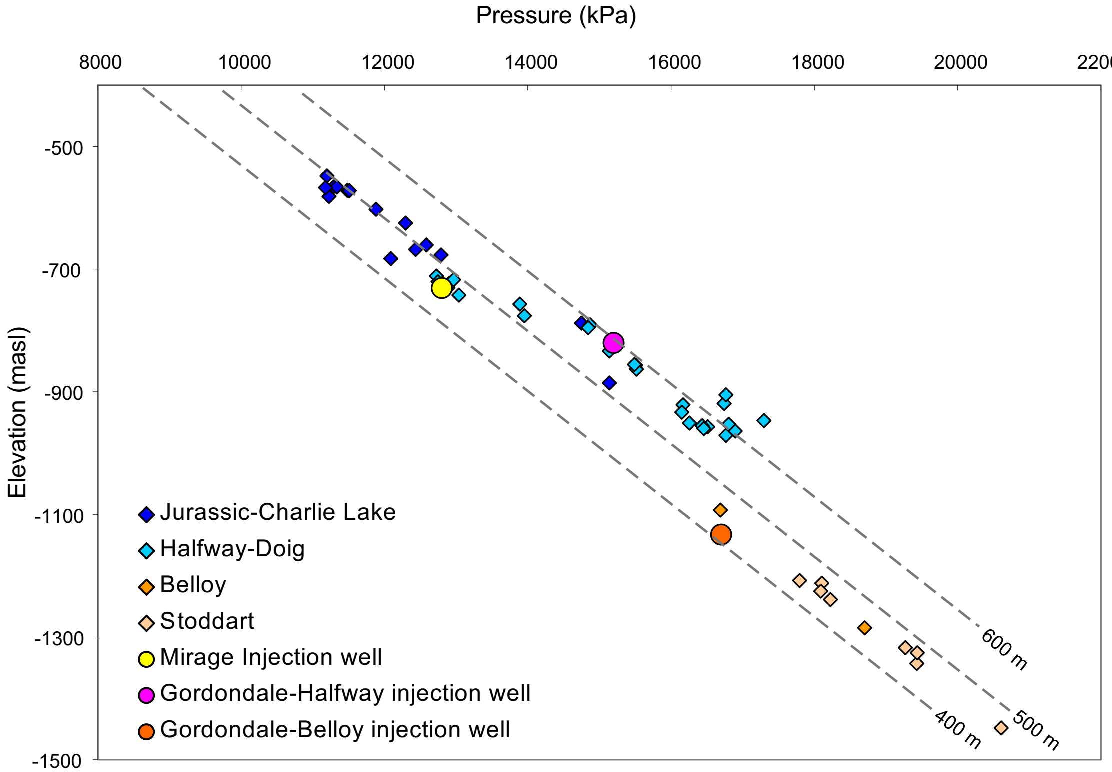


Figure 87. Distribution of pressure versus elevation in the injection strata (Belloy and Halfway formations) and adjacent formations in the local-scale study area of the Gordondale and Mirage acid-gas injection operations. The dashed lines delineate pressure-elevation trends with equal hydraulic-head values and the potential for vertical flow may be inferred perpendicular to those lines from high to low values.

Rock Properties

The Belloy-Stoddart and Halfway-Doig aquifers that host the injection units in the Gordondale area are formed mainly by sandstones. Therefore, the various sandstone formations have a similar range in porosity and permeability values (Table 21). Generally, the average well-scale porosity is below 10 %, the median well-scale horizontal and vertical permeability are between 1 – 40 mD and between 0.5 and 9 mD, respectively. Permeability values calculated at the reservoir scale from DST data range between less than 1 mD to 78 mD with median values of 2 mD and 9 mD in the Belloy-Stoddart and Halfway-Doig aquifers, respectively.

Table 21.Well-scale porosity and permeability values obtained from measurements in core plugs from the Kiskatinaw (14 wells), Belloy (2 wells), Doig (44 wells), and Halfway (98 wells) formations in the Gordondale area. Also shown are permeability values calculated from 11 drillstem test analyses performed in the Belloy-Stoddart aquifer, and from 13 DST analyses in the Halfway-Doig aquifer.

	Porosity (%)			Horiz. Perm. (mD)			Vert. Perm. (mD)			DST Perm. (mD)		
Formation	Min	Max	Avg	Min	Max	Median	Min	Max	Median	Min	Max	Median
Halfway	0.8	17	8.4	0.005	189	17.4	0.014	100	8.8	0.4	46	9
Doig	0.7	14	5.6	0.005	55	5.0	0.010	32	4.8			
Belloy			7.8			38.4			1.9	0.3	78	2
Kiskatinaw	1.6	8.2	5.2	0.14	16	0.9	0.13	7	0.6			

Flow of Formation Water

Initially northward flow of formation water in the Belloy aquifer is channelled along the graben north of the Gordondale Fault towards the northeast. The hydraulic gradient is relatively low, indicating good lateral hydraulic connectivity in the aquifer. Flow patterns in the overlying Halfway-Doig aquifer are different, showing overall higher hydraulic-head values and changes in hydraulic gradients. In addition, salinity of formation water, appears to be higher in the Halfway-Doig aquifer (170 g/l) than in the underlying Belloy aquifer (140-165 g/l), which is reversed to the generally observed salinity increase with depth on a regional scale. These differences in hydrogeology between the two aquifers clearly show that the intervening Montney aquitards is an effective barrier to vertical flow and that the faults, although they appear to penetrate Triassic and Permian strata, are not vertical flow conduits. Rather, faults have a channelling effect on formation water flow in the Belloy aquifer, whereas faults play a role in obstructing lateral flow in the Halfway-Doig aquifer.

5.9 Summary of the Local-Scale Hydrogeological Analysis

Injection of acid gas in the Peace River Arch area occurs in three major hydrostratigraphic units, the Upper Devonian aquifer system, the Belloy-Stoddart aquifer and the Halfway-Doig aquifer, which were each affected differently by Peace River Arch tectonics. Faults in the Devonian succession were post-depositional and may have facilitated the vertical migration of dolomitizing fluids, which resulted in the formation of secondary porosity and locally enhanced permeability in Leduc and Wabamun carbonate reservoirs. However, the faults only appear to affect the lateral present-day flow of formation water in the Devonian aquifer in the Puskwaskua and Normandville areas. Faulting in the Stoddart to Belloy sedimentary succession was syn-depositional, mainly resulting in a thickening of strata in the center of grabens. As a result, in the grabens the aquifer transmissivity increases whereas aquitards provide better vertical sealing capacity compared to areas outside the graben. Along major faults, the Kiskatinaw and Golata formations may be completely displaced, which may result in the lateral and vertical isolation of parts of the Kiskatinaw aquifer (Pouce Coupe area), or the juxtaposition of the Kiskatinaw and Debolt aquifers (Rycroft area). In addition, horst and half graben structures create structural traps at the top of the Belloy and Kiskatinaw aquifers (Mulligan, Dunvegan), impeding and/or channelling the lateral migration of buoyant fluids like hydrocarbons or acid gas. In general, the faulting in the Stoddart-Belloy succession influences the lateral migration of fluids, whereas the thick overlying Triassic Montney shales show only small displacements that do not appear to affect the overall aquitard integrity. Most faults in the Peace River Arch area terminate in the Permian or Lower Triassic strata and fluid flow in the Middle Triassic Halfway-Doig aquifer is not directly influenced by structural elements.

5.10 Site Specific Characteristics of the Acid-Gas Operations

The site-specific characteristics of the acid gas operations in the Peace River Arch area are summarized in Table 22. 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.

Two of the 12 acid-gas injection sites in the Peace River Arch area (Gordondale-Halfway and Mirage) were rescinded. At Mirage, acid gas was mixed with produced water and injected into the Halfway "B" pool as part of a waterflood scheme between 1996 and 1998, but the operation was rescinded due to the closure of the associated gas plant. The natural gas from that area is currently processed at the Gordondale plant.At Gordondale, acid gas was initially injected into a reservoir in the Halfway

Table 22. Characteristics of acid-gas injection operations in the Peace River Arch area.

	Operation Description	Dunvegan	Eaglesham	Gordondale-Halfway	Gordondale-Belloy	Mirage	Mulligan	Normandville	Parkland	Pouce Coupe	Puskwaskua	Rycroft	Wembley
Injection Operations	Gas Plant	Dunvegan Plant	Culp West Plant	Gordondale Plant	Gordondale Plant	Mirage Gas Plant	Fourth Creek Plant	Normandville plant	Parkland plant	Pouce Coupe plant	Puskwaskua plant	Rycroft plant	Wembley plant
	Current Operator	Devon Canada Corp.	Devon Canada Corp.	Duke Energy	Duke Energy	Summit Resources Ltd.	Duke Energy	Devon Canada Corp.	Petro-Canada	Duke Energy	Devon Canada Corp.	Devon Canada Corp.	Conoco Canada Resources
	Approval Date	1-Jan-96	6-Nov-00	21-Dec-95	3-Jun-98	2-Oct-95	6-Dec-96	29-Sep-97	22-Feb-01	19-Feb-99	21-Feb-96	6-Dec-01	20-Sep-02
	Status	active	active	rescinded	active	rescinded	active	active	active	active	active	active	active
	Location (DLS)	15-03-081-04-W6	05-34-078-25-W5	11-26-079-09-W6	11-26-079-09-W6	04-20-079-07-W6	15-11-082-09-W6	103-36-079-23-W5	06-29-081-15-W6	05-23-080-13-W6	03-26-074-01-W6	07-02-077-04-W6	06-19-073-08-W6
	Latitude (N)	55.996	55.790	55.878	55.878	55.86	56.1	55.882	56.056	55.947	55.432	55.642	55.336
	Longitude (W)	-118.529	-117.796	-119.291	-119.291	-119.07	-119.280	-117.466	-120.312	119.927	-118.040	-118.502	-119.220
	KB Elevation (m AMSL)	601.5	570.4	733.5	771.2	660.2	724.3	571.7	712.7	634.9	624.5	665.7	750.2
	Depth of Injection Interval (m)	1355-1390	1927-2058	1552-1556	1905-1942	1391-1401	1589-1634	1745-1840	2443-2456	2036-2118	2677-2695	1760-1801	2407-2450
	Average Injection Depth (m)	1372.5	1940	1554	1923.5	1396	1608	1792.5	2449.5	2077	2686	1780.5	2428.5
Reservoir Geology	Injection Formation Name	Kiskatinaw Fm.	Wabamun Group	Halfway Fm.	Belloy Fm.	Halfway Fm.	Belloy Fm.	Wabamun Group	Basal Kiskatinaw Fm.	Belloy Fm.	Upper Leduc Fm.	Kiskatinaw Fm.	Belloy Fm.
	Injection Formation Lithology	Sandstone	Dolostone	Sandstone	Sandstone	Sandstone	Sandstone	Dolostone	Sandstone	Sandstone	Dolostone	Sandstone	Sandstone
	Injection Formation Thickness (m)	35	131.0	4	37.0	10.0	45	95	13	82	18	41	43
	Net Pay (m)	8	50	4.0	13	6	29	88	10	10	18	23.6	26
	Caprock Formation	U. Kiskatinaw & Taylor Flat fms.	Exshaw Fm.	Charlie Lake Fm.	Montney Fm.	Charlie Lake Fm.	Montney Fm.	Exshaw Fm.	U. Kiskatinaw Fm.	Montney Fm.	Ireton Fm.	Taylor Flat Fm.	Montney Fm.
	Caprock Formation Lithology	Shale & anhydrite	Shale	Anhydrite	Shale	Anhydrite	Shale	Shale	Shale	Shale	Shale	Shale	Shale
	Caprock Thickness (m)	85	8	101	250	15	264	10	25	250	18	20	199
	Underlying Formation	Golata Fm.	Winterburn Gp.	Doig Fm.	Taylor Flat Fm.	Doig Fm.	Taylor Flat Fm.	Winterburn Gp.	Golata Fm.	Taylor Flat Fm.	Middle Leduc Fm.	Golata Fm.	Taylor Flat Fm.
	Underlying Formation Lithology	Shale	Carbonates & shale	Shaly siltstone	Sandstone & shale	Shaly siltstone	Sandstone & shale	Carbonates & shale	Shale	Sandstone & shale	Carbonates	Shale	Sandstone & shale
	Underlying Thickness (m)	21	100	79	239	25	90	50	30	70	85	30	45
Rock Properties	Porosity (fraction)	0.21	0.05	0.12	0.12	0.12	0.2	0.05	0.09	0.12	0.16	0.11	0.12
	Permeability (md)	500	38.00	14.50	29.50	24.00	6	11	6	9	109	10	1
	SV (MPa)	31.6	46.5	37.3	46.4	33.3	36.3	40.9	59.4	50.2	64.4	41.9	60.1
	SV Gradient (kPa/m)	23.3	24.1	24.0	24.4	23.9	22.8	23.4	24.3	24.7	24.1	23.8	25
	SHMIN (MPa)	22.8	31.0	24.5	29.9	26	26.5	26.2	39.1	33.7	48	29.1	40.9
	SHMIN Gradient (kPa/m)	16.8	16.1	15.8	15.7	18.7	16.7	15	16	16.6	17.9	16.5	17
Reservoir Properties	Original Formation Pressure (kPa)	13035	20317	15200	16700	12800	13744	17982	23133	20000	28588	16500	23084
	Formation Temperature (°C)	47.0	63.0	68.0	76.0	60.0	60	58	82	76	82	63	82
	Reservoir Volume (1000 m3)	182	115	n/a	610	n/a	209	52.4	616	330	74.4	379.2	2320
Formation Water	TDS Calculated (mg/L)	156722	249145	123688	162000	25535*	156804	198150	193167	81674	283743	162000	159216
	Na (mg/L)	52095	66500	43000	53400	9289*	54500	54437	58667	26335	73600	60100	55253
	Ca (mg/L)	5485	23220	1200	4760	340.8*	5240	17240	10650	1962	24300	4330	2505
	HCO3 (mg/L)	278	237	986	471	869*	257	237	227	488	114	207	795
Licensed Injection Operations	Injected Gas - CO2 (mole fraction)	0.45	0.61	0.28	0.49	0.24	0.46	0.89	0.53	0.54	0.74	0.39	0.33
	Injected Gas - H2S (mole fraction)	0.42	0.37	0.65	0.49	0.68	0.48	0.09	0.46	0.44	0.22	0.58	0.58
	Maximum Approved H2S (mole fraction)	0.41	0.80	0.75	0.65	0.68	0.55	0.67	0.59	0.7	0.42	0.7	0.7
	Maximun Approved WHIP (kPa)	7100	12000	5000	8000	13000	9000	9000	6500	9000	12300	5500	19000
	Maximum Approved Injection Rate (1000 m3/d)	5	18.3	27	60	4.2	21	2.8	15	42	12	25.4	150
	Total Approved Injection Volume (103 m3)	18700.00	35000.00	34500	263000	16000	58200	8100	37000	150000	40000	180000	956000
	EPZ (km)	3.70	5.00	3	4	1.10	2.2	3.7	3	5	5.5	3.8	5
						*diluted sample of waste water used for flooding							

Formation from 1996 to 1998. After breakthrough of acid gas at neighbouring production wells, the operator switched to injection into the Belloy Formation in 1998.

The composition of the injected acid-gas at the various injection operations ranges from 24 % CO_2 and 68 % H_2S at Mirage to 89 % CO_2 and 9 % H_2S at Normandville, other hydrocarbon gases making up the balance. The depth of the injection interval varies between 1355 m at Dunvegan and 2677 m at the Puskwaskua 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 all cases of acid-gas injection operations in the Peace River Arch area, a series of aquitards overlying the respective injection horizon prevents vertical migration of acid gas into shallow groundwater aquifers or to the ground surface (see Figure 29 and downhole models in Appendix 1). In addition to the Charlie Lake aquitard that overlies the injection target in the Halfway Formation, the shales in the Fernie and Fort St. John groups and Upper Cretaceous strata form extensive aquitards farther up in the succession. The Belloy and Kiskatinaw injection intervals are capped by an additional thick aquitard, the Montney shales. The latter is not present in the area where acid gas is injected into the Upper Devonian succession, in which case the Banff-Exshaw aquitard provides an additional barrier to vertical acid-gas migration.No breakthrough of acid gas has been reported to date in any wells producing from horizons overlying an acid-gas injection interval. This suggests that the respective aquitards directly overlying the injection intervals contain the injected acid gas 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, 15, 17, 19 and 21).

Vertical stresses, S_V, at the top of the various injection intervals vary between 31.6 MPa at 1355 m depth and 64.4 MPa at 2677 m depth, reflecting the thickness and density of the strata that overlie the injection interval (Table 22). 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 23.3 kPa/m and 25.0 kPa/m, reflecting variations in rock density. Minimum horizontal stresses, S_{Hmin}, in the various injection intervals vary between 22.8 MPa and 40.9 MPa (Table 22) and corresponding gradients between 15.0 kPa/m to 18.7 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, the pressure has to increase 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 88); 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,

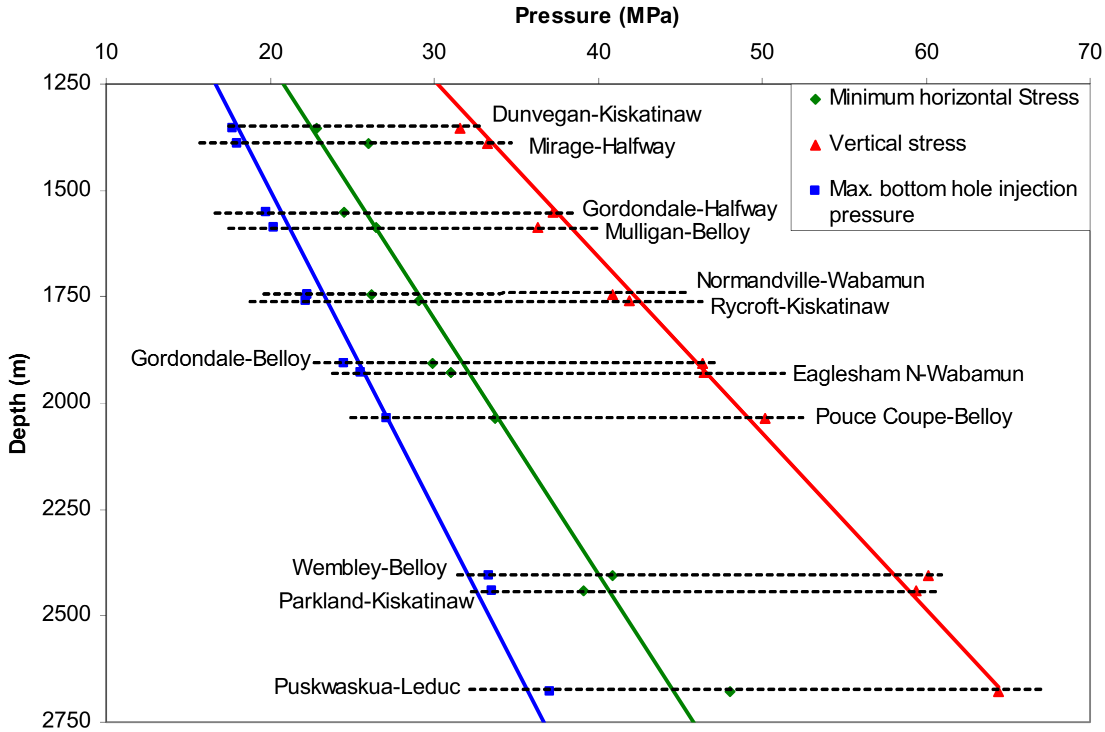


Figure 88. Maximum bottom-hole injection pressure in relation to minimum horizontal stress and vertical stress at the various injection sites in the Peace River Arch area.

and wellhead pressure and temperature.

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 modelling 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).

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 Peace River Arch 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 12 injection sites in the Peace River Arch area can be split into two categories:

- Injection into depleted hydrocarbon reservoirs at Dunvegan, Eaglesham, Gordondale (Halfway), Mirage, Normandville, Parkland, and Puskwaskua.
- Injection into deep saline aquifers at Gordondale (Belloy), Mulligan, Pouce Coupe, Rycroft and Wembley.

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, within which 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 distinct lateral physical constraints to the flow of the injected acid gas.

6.1 Injection of Acid-Gas into Reservoirs

The fate of the acid gas injected into hydrocarbon reservoirs is controlled by the in-situ properties of the gas and the native reservoir fluids. Table 23 presents the density and viscosity of the injected acid gas and native reservoir gas fluid calculated for the initial in-situ conditions given in Table 22 (Adams and Bachu, 2002; Bachu and Carroll, 2004).

6.1.1 Sour Water Injection at Mirage

Because sour water rather than "dry" acid gas was injected at Mirage, this case will be treated separately from the other six injection sites in the Peace River Arch area that inject into depleted reservoirs. Initially, oilfield produced water was injected (disposed of) at Mirage. Subsequently the operator was granted permission to co-dispose of acid gas by dissolving it into the produced water prior to injection.

At Mirage, acid-gas mixed with produced water was injected through three wells into the Halfway "B" pool for 15 months from 1995 to 1996 as part of a water flood.As a result, a total of 2.6 million cubic metres of acid gas were disposed of in the Halfway "B" pool. Acid-gas injection was rescinded due to the decommissioning of the associated gas plant. Of the three injection wells, one was re-completed and produces from the overlying Cadomin Formation, one was suspended and the third continues to dispose of water into the injection horizon (Figure 89). The outline of the "B" pool was changed in 2005 by the EUB based on production performance and re-mapping of the sand net pay. The southeast part of the initial pool designation is now part of the Halfway "D" pool, which is separated laterally from the "B" pool by a change in lithofacies of the Halfway Formation from sand to shale. Currently, seven wells produce oil and water from the Halfway Formation (Figure 90a), and migration of sour water will be constrained to the pool outline. An additional two wells produce from the overlying Cadomin and Dunvegan formations, three wells were abandoned, two are suspended and one well is a water injector. The potential for leakage along abandoned wells is low because the first wells in the Mirage area were drilled in the 1970s (Figure 90b) and well abandonment did not start before the 1980s, when more stringent abandonment guidelines were in place.

Currently, the Mirage pool still produces oil from the Halfway Formation. Therefore, a portion of the injected sour water is most likely produced back through the active oil wells. 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 Halfway pool at Mirage 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 Halfway 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 Halfway Formation, 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 Halfway channel sands. Mixing with and diffusion within the

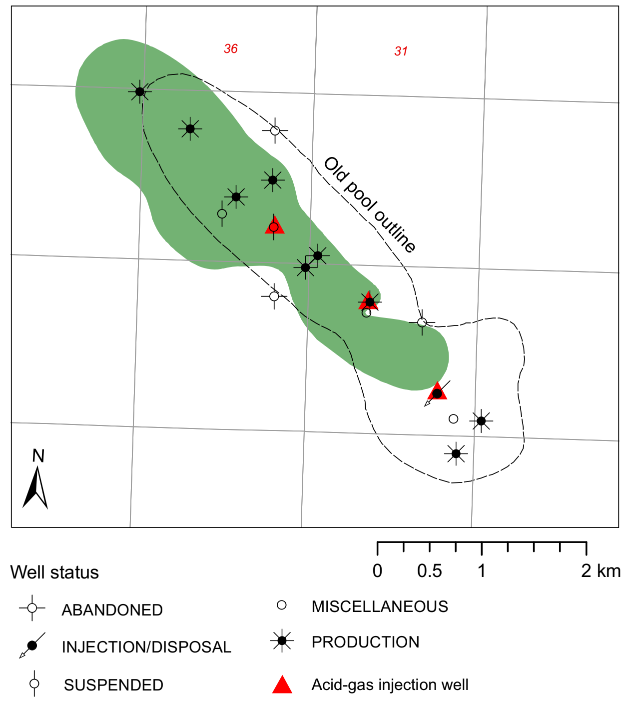


Figure 89. Location and current status of wells that penetrate the injection horizon within the limits of the Mirage Halfway B oil pool (green). The pool is located in township 79, ranges 7 and 8 (see Figure 83a). Sections are numbered in red.

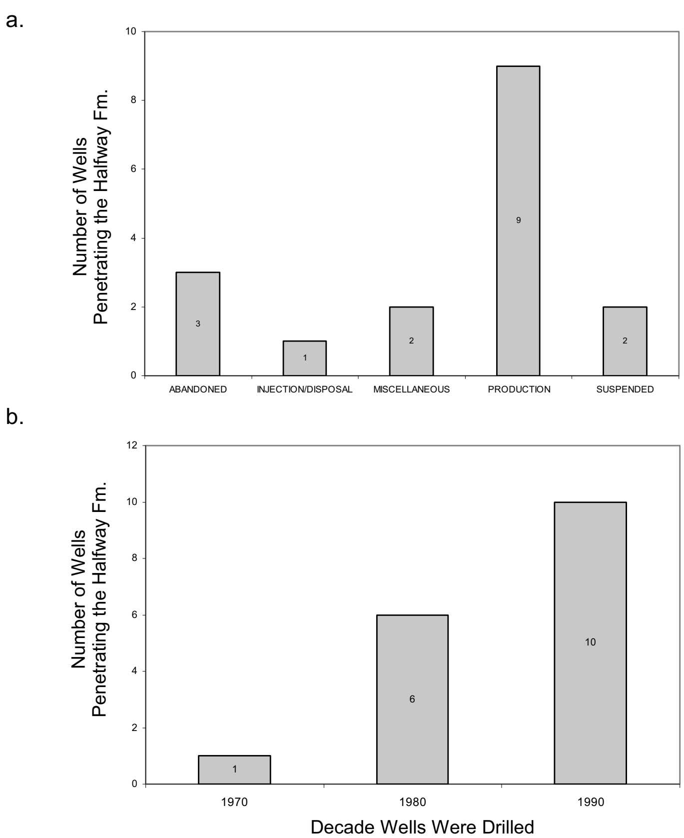


Figure 90. Histograms for wells that penetrate the Halfway Formation in the Mirage-Halfway B pool showing: a) well status, and b) time of drilling.

formation water in the 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 the aquifer, generating convective flow. There, the sour water will be subjected to hydrodynamic forces in the natural flow system of the Halfway-Doig aquifer and to negative buoyancy that will drive the water downdip.

Table 23. Properties of native fluids and injected acid gas at in-situ conditions at the six operations in the Peace River Arch area where acid-gas is or was injected into hydrocarbon reservoirs.

Fluid Property	Dunvegan	Eaglesham	Normandville	Parkland	Puskwaskua	Gordondale Halfway
Native Fluid	Gas	Oil	Oil	Oil	Gas	Oil
ρ (kg/m^3)	108	747	730	629	106	677
μ (mPa s)	0.016	1.2	0.9	0.4	0.017	0.5
ρ_{ag} (kg/m^3)	545	690	652	699	665	570
μ_{ag} (mPa s)	0.049	0.064	0.053	0.065	0.057	0.056

6.1.2 Dunvegan

A total of 25 million m^3 of gas and 2275 m^3 of water were produced from the Dunvegan Kiskatinaw A pool through a single well from August 1994 to June 1995. During that time, reservoir pressures declined rapidly from 13,035 kPa to 6100 kPa, suggesting that the pool is hydraulically contained, both vertically and laterally. After depletion of the gas pool, the well was turned into an acid-gas injection well, starting injection in November 1996. By the end of 2006, approximately seven million cubic metres (37 % of the approved volume) of acid gas have been injected into the Kiskatinaw A pool.

There are 10 additional wells located within the limits of the Kiskatinaw A pool that penetrate the injection horizon, nine of which produce gas from the underlying Debolt Formation and one is a suspended Gething (Bullhead Group) gas producer (Figures 91 and 92a). These wells are of a relatively young age (Figure 92b) and completed for sour gas production, which suggests that the potential of acid-gas leakage along boreholes in this area should be small.

The southwest boundary of the Kiskatinaw A pool is formed by the Dunvegan Fault. Due to the syn-depositional character, there are no sediments of the Kiskatinaw Formation present directly southwest of the fault (see cross-section Figure 60). The unnamed fault that runs parallel to the Dunvegan fault appears to limit the extent of the reservoir-quality sandstone to the northeast. The faults do not appear to offset significantly the overlying Taylor Flat Formation, which forms a local seal to the gas pool and upward vertical leakage of gas along these faults is unlikely.The vertical and lateral isolation of the Kiskatinaw A pool is manifested also in the fast depletion of the reservoir pressures. Both faults do not penetrate the Montney aquitard; hence, in the unlikely event of vertical leakage of injected acid gas, the spread of an acid-gas plume would be limited to within the overlying Belloy aquifer.

6.1.3 Parkland

The Parkland Basal Kiskatinaw B pool produced a total of 70 million m^3 of gas and 335 m^3 of water through a single well from July 1993 to August 2001. During that time, reservoir pressures declined from 23,133 kPa to 2179 kPa, suggesting that the pool is hydraulically contained, both vertically and laterally. After depletion of the gas pool, the well was turned into an acid-gas injection well, starting injection in

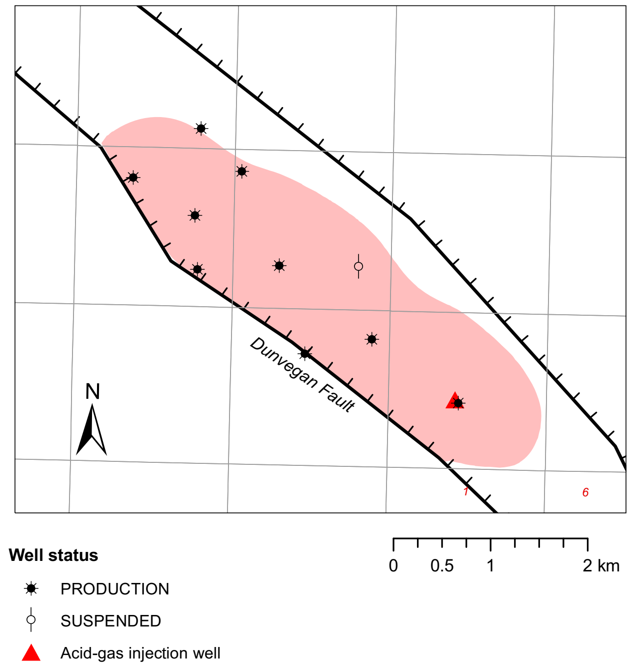


Figure 91. Location and current status of wells that penetrate the injection horizon within the limits of the Dunvegan Kiskatinaw A oil pool in Tp 84 R4 W6 (red). Sections are numbered in red.

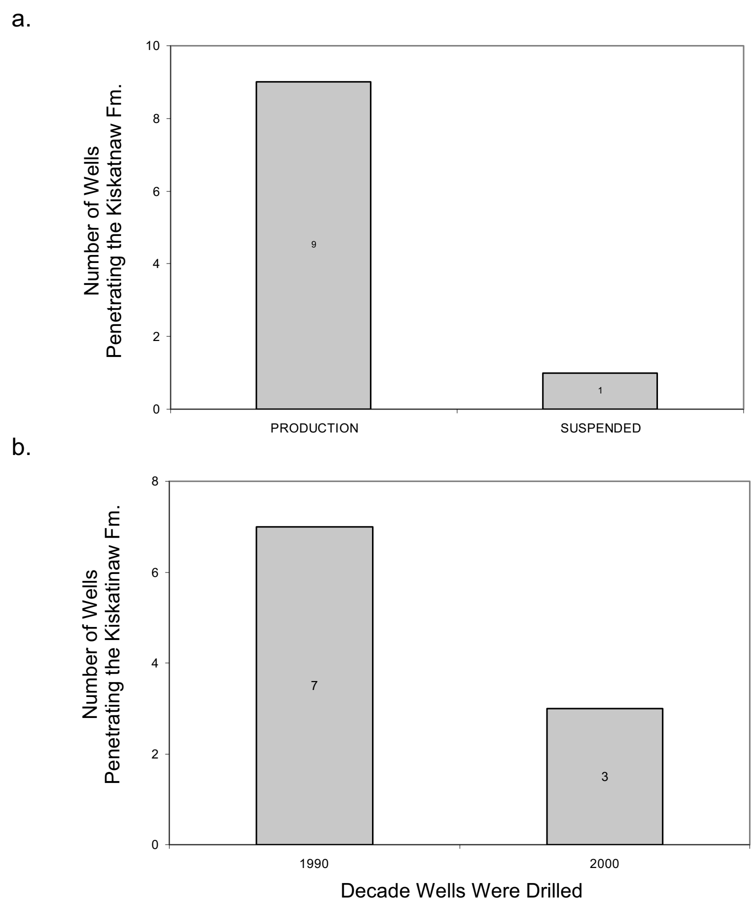


Figure 92. Histograms for wells that penetrate the Kiskatinaw Formation in the Dunvegan-Kiskatinaw A pool showing: a) well status, and b) time of drilling.

August 2001. By the end of 2005, approximately 12 million cubic metres (32 % of the approved volume) of acid gas have been injected into the Basal Kiskatinaw B pool. No injection data was available for 2006.

The vertical and lateral isolation of the Basal Kiskatinaw B pool is manifested in the fast depletion of the reservoir pressures. In addition, the large difference in pressures between the Kiskatinaw Formation and the overlying Belloy Formation shows that the intervening Taylor Flat Formation forms a vertical barrier to flow. The lateral boundaries of the Basal Kiskatinaw B pool (Figure 93) are formed by intra-formational changes in lithology from sandstone to shale. It is not anticipated that by injecting the maximum approved volume of acid gas the reservoir pressures will reach initial reservoir pressure. Therefore, the Basal Kiskatinaw B pool will remain underpressured with respect to the surrounding aquifers, preventing the migration of acid gas beyond the pool boundaries.

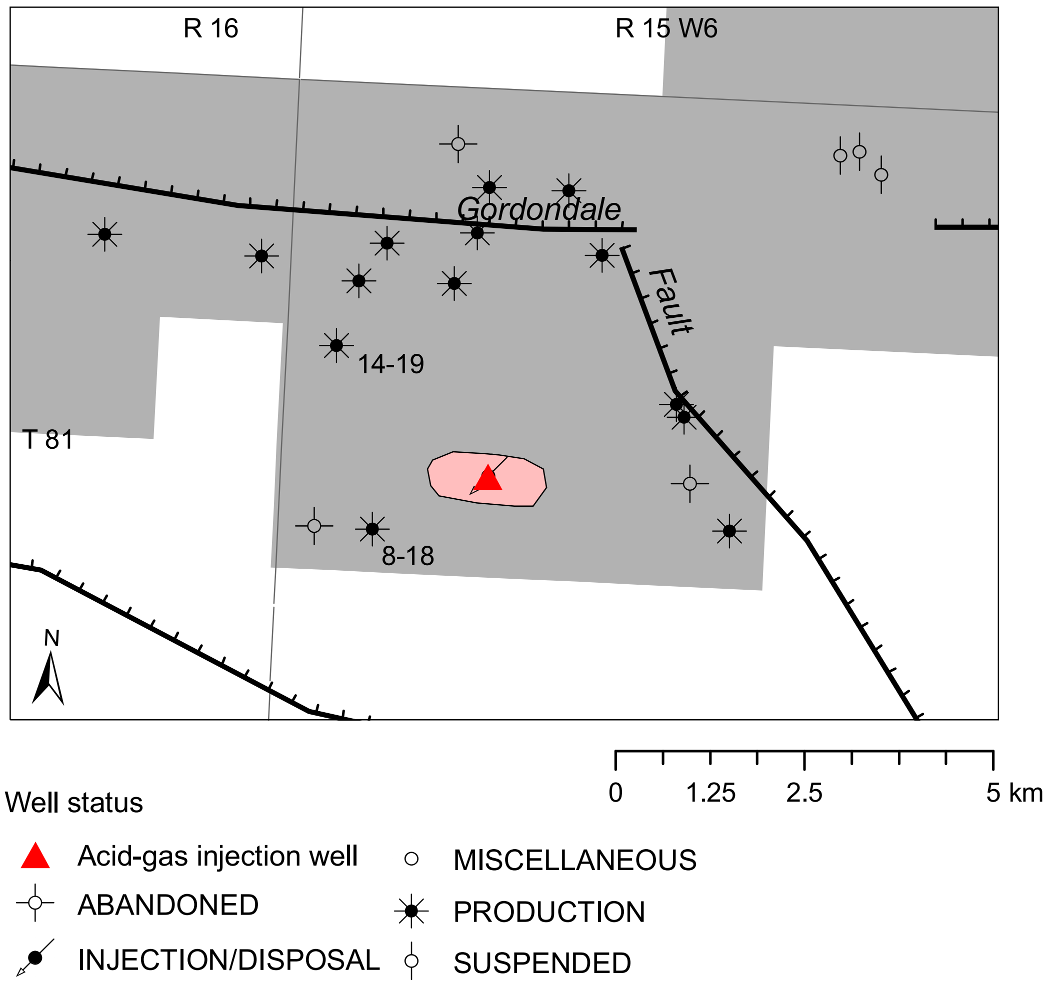


Figure 93. Location and current status of wells that penetrate the injection horizon within the Parkland oil field (grey). Injection occurs into the depleted single-well Basal Kiskatinaw B pool (red).

The closest wells currently producing gas from the Kiskatinaw Formation in the Parkland Field are located at a distance of 1.7 km (8-18-81-15W6) and 2.6 km (14-19-81-15W6) from the injection well. Given the lateral lithofacies changes from permeable sandstone to low-permeability siltstone and shale in the Kiskatinaw Formation, it is unlikely that the producing wells will affect pressures in and acid-gas migration from the Basal Kiskatinaw B pool. There are no additional wells in the Basal Kiskatinaw B pool that could create potential leakage paths. The faults identified in the area are at least 2.2 km away from the reservoir and are unlikely to be contacted by any migrating acid gas.

6.1.4 Eaglesham and Normandville

Production of oil in the Eaglesham area has been from various, mostly single-well pools completed in the upper part of the Devonian Wabamun Group (Figure 94). The Normandville and Eaglesham North operations each have been injecting acid gas into one of the depleted pools since 1997 and 2000, respectively. The Normandville D-1 E oil pool was produced from through a single well from July 1990 to February 1994, resulting in a cumulative production of 24,400 m^3 of oil, 2.2 million m^3 of gas and 9,900 m^3 of water. Due to the pressure support from the underlying Wabamun aquifer, initial reservoir pressures of 17,982 kPa did not decline during the production period. The former production well switched to acid-gas injection in October 1997 and by the end of 2006, approximately 2.6 million m^3 (32% of the approved total volume) of acid-gas have been injected into the Normandville D-1 E pool. Oil production from the Eaglesham North D-1 N pool lasted from November 1989 until October 1995. A total of 21,500 m^3 oil, 2.2 million m^3 gas and 72,800 m^3 water were produced from the D-1 N pool, before it was shut in due to uneconomically high water cuts. Similar to the Normandville D-1 E pool, reservoir pressure of the Eaglesham North D-1 N pool declined only slightly (~ 100 kPa) due to the hydraulic communication with the underlying Wabamun aquifer.Acid-gas injection through the former production well started in November of 2000, and by the end of 2006 approximately 9.8 million m^3 of acid gas (28% of the total approved volume) have been injected into the reservoir.

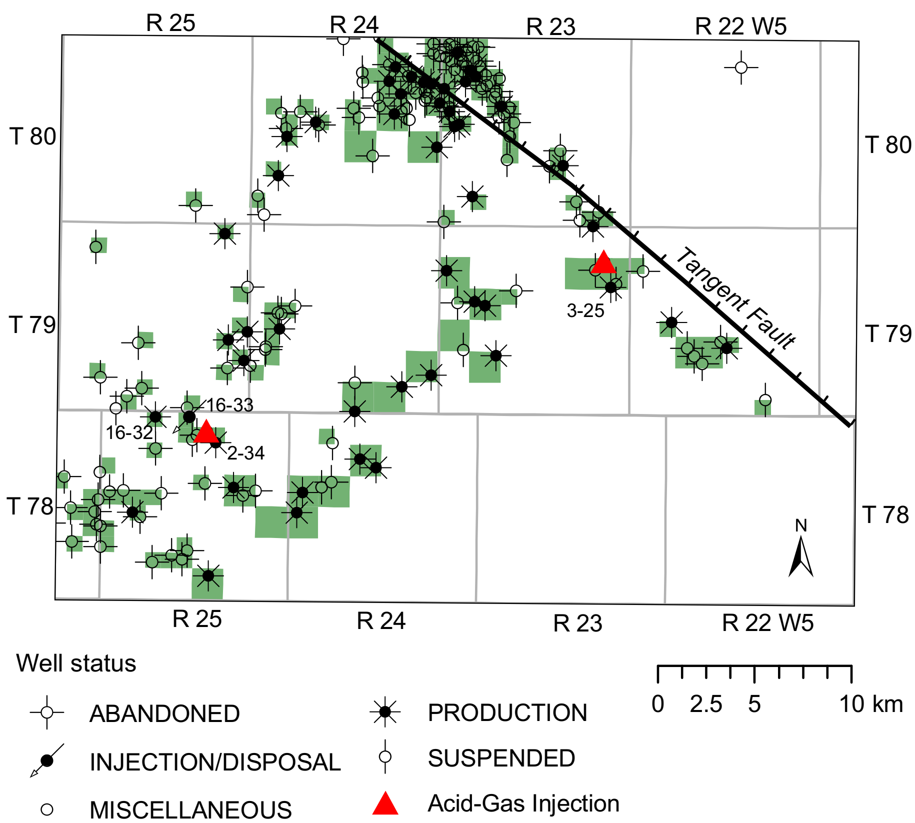


Figure 94. Location and current status of wells that are completed in the Wabamun Group in various small (single well) oil pools (green) in the Normandville area.

Vertical containment of the injected acid gas in the respective reservoirs is warranted by the fact that these reservoirs trapped oil with comparable fluid density as that of the acid gas for thousands of years. In addition, the hydrogeological data show that the overlying Exshaw-Lower Banff aquitard is an effective barrier to flow. The total approved volume of injected acid-gas is less than the equivalent volume of previously produced hydrocarbons and water; hence, the injected acid-gas plume should not extend laterally beyond the respective pool boundaries. Although the various Wabamun pools are considered isolated from each other, the pressure data suggest that the dolomitized reservoir bodies are well connected to the underlying Wabamun aquifer. Therefore, there is the potential for acid-gas dissolving into the formation water, and being carried by the regional flow in the Wabamun aquifer. However, being dissolved in formation water and considering the very low flow velocity (< 1 m/year) there is no threat for any acid-gas contaminating shallower aquifers. Still, currently producing wells from neighbouring Wabamun pools represent fluid sinks and might draw nearby-injected acid-gas in their direction. In fact, three wells (2-34, 16-33, and 16-32-78-25W5 in Figure 94) were recently drilled and completed in the Wabamun Group at a distance of approximately 750 m, 1,100 m, and 2500 m from the Eaglesham acid-gas injection well, respectively. These wells were drilled after the approval and commencement of acid-gas injection, two of them producing oil and one disposing of water into the Wabamun Group. The two producers have potential for co-producing some of the injected acid gas. Similarly, the 3-25-79-23W5 well (Figure 94) producing oil from a Wabamun pool at a distance of 1,400 m from the Normandville injection site has the potential for co-production of injected acid gas. However, no data to either confirm or contradict co-production of injected acid-gas was available at the time this report was written and further investigation of this issue is required.

Of the 167 wells that are completed in the Wabamun Group in the Eaglesham area, 87 wells are abandoned, 28 wells are suspended, 2 wells dispose of water and 50 wells produce oil (Figure 95a). The majority of the wells were drilled in the 1980s and 1990s (Figure 95b). The potential for leakage along abandoned wells is low, because well abandonment did not start before the 1980s (Figure 95c), when more stringent abandonment guidelines were in place.

Although the Tangent Fault appears to have been a fluid conduit at the time of dolomitization of the Wabamun Group limestone in the late Mississippian, there is no indication for present-day leakage along this fault.

6.1.5 Puskwaskua

The Leduc D-3 A pool (Figure 96) is formed by a small pinnacle reef from which oil was produced through three wells between February 1984 and July 1993. The pool produced a total 52,000 m^3 of oil and 250,000 m^3 of formation water. The reservoir pressure measured in November 1995 (28,422 kPa) was essentially the same as the initial reservoir pressure (28,588 kPa), suggesting that the D-3 A pool is in pressure communication with the underlying Leduc aquifer. The 14-23 well started injecting acid-gas in November 1996 and by the end of 2006, a total of 5.4 million m^3 of acid gas (14 % of the total approved volume) have been injected into the Leduc D-3 A pool. The 6-26 well was under production for only 9 months, after which it has been disposing of approximately 360,000 m^3 of produced water into the D-3 A pool by the end of 2006. The third well completed in the D-3 A pool, the 1-26 well, was abandoned and re-completed farther up in the stratigraphic column to produce gas from the Mississippian Debolt Formation.

The fact that the D-3 A pool trapped oil with comparable fluid density as that of the acid gas for thousands of years shows that the overlying Ireton shales form an effective seal at the top of the reservoir. The large volume of disposed water through the 6-26 well enhances the dissolution of injected acid gas a.

b.

c.

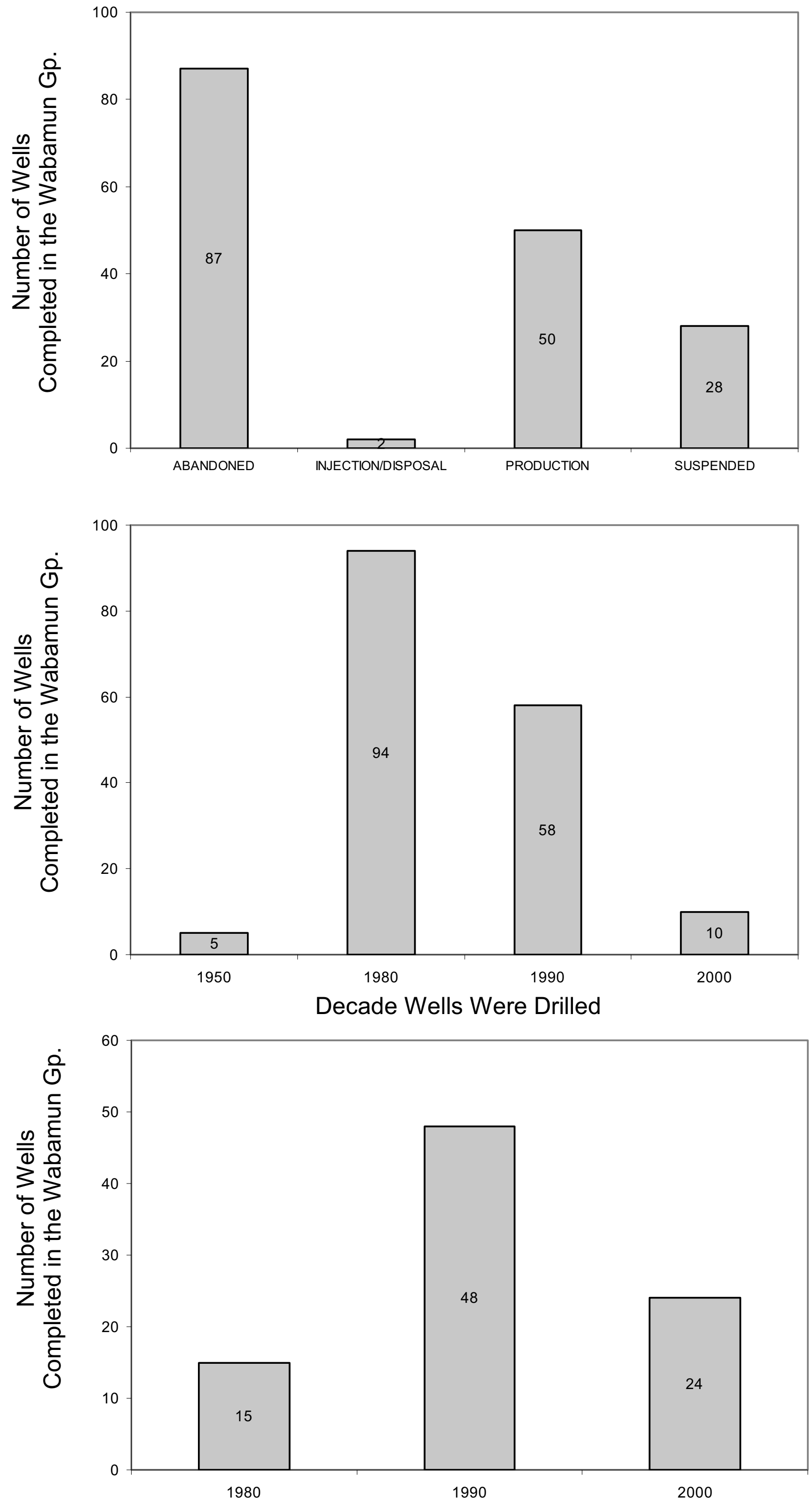


Figure 95. Histograms for wells that are completed in the Wabamun Group in the Normandville area showing: a) well status, b) time of drilling, and c) time of abandonment.

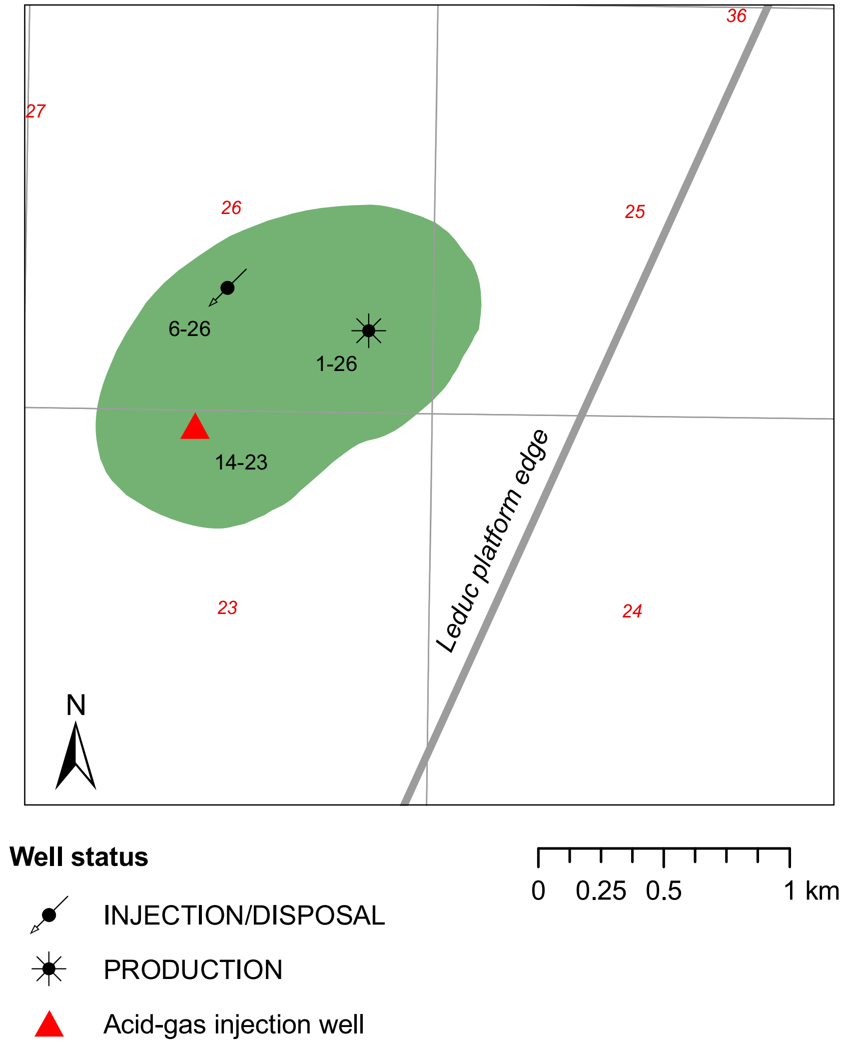


Figure 96. Location and current status of wells that penetrate the injection horizon in the Puskwaskua D-3A oil pool (green) in TP 74 R 1 W6. Sections are numbered in red.

in the formation water and it is unlikely that a separated-phase plume of acid gas will form at the top of the reservoir. On the other hand, this large volume of disposal water might force sour water to migrate beyond the spill point of the D-3 a pool into the underlying Leduc aquifer. However, taking in account the low acid-gas injection rate (~ 500 m^3/day) it is unlikely that dissolved acid-gas concentrations in Leduc formation water will be noticeable farther than a hundred meters beyond the pool boundaries. Only two wells penetrate the injection horizon near the injection well. These two wells are still active, limiting the risk of leakage along boreholes. No faults were identified in the area of the D-3 A pool that could form leakage pathways for injected acid gas.

6.1.6 Gordondale-Halfway

At Gordondale, acid-gas injection commenced in May 1996 in the southeast corner of the Triassic Halfway K pool (Figure 97). After less than a year, the operator had to shut in the 14-23-79-9W6 producer approximately 800 m away from the injection well due to acid-gas breakthrough and because the producer was not equipped to handle the increased H_2S concentrations. After approximately 13 months of

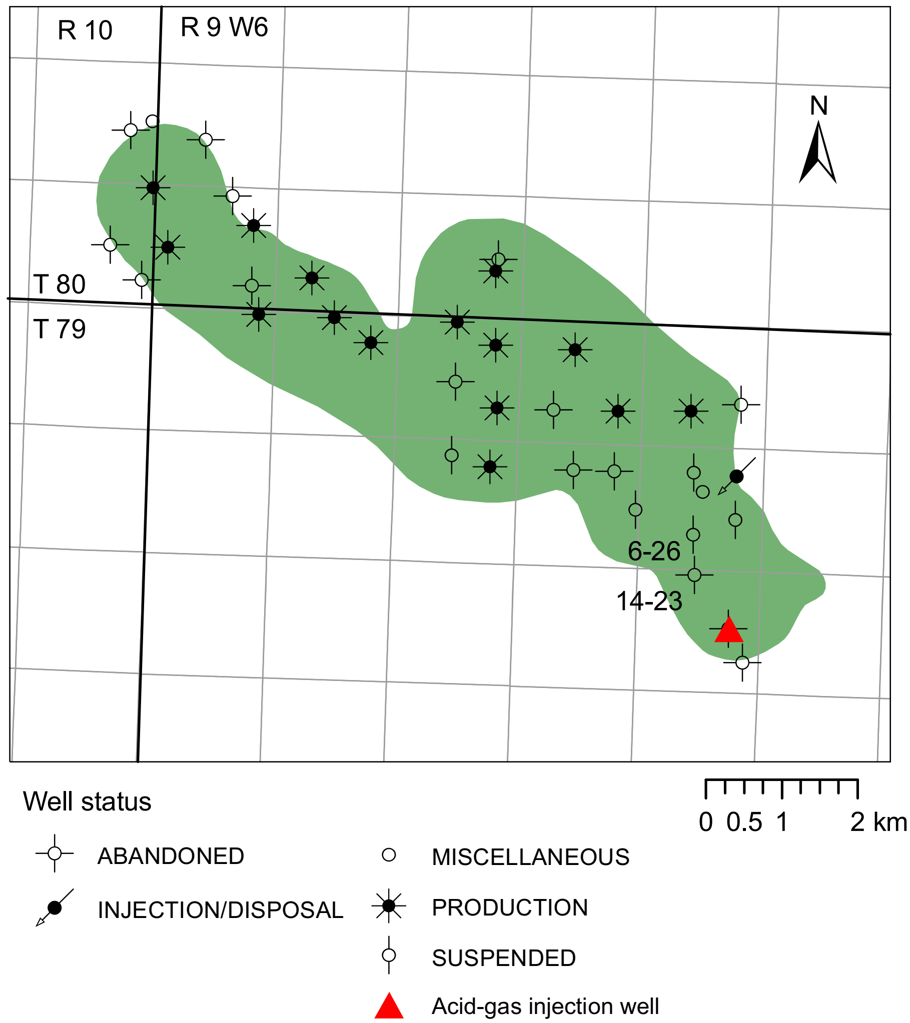


Figure 97. Location and current status of wells that penetrate the injection horizon within the limits of the Gordondale Halfway K oil pool (green).

injection, breakthrough of acid gas was detected in a second production well, 6-26-79-9W6, at a distance of 1300 m. After injection of 9 million cubic metres of acid gas, the operator moved to injection through a nearby well into the Permian Belloy aquifer, rescinding injection into the Halfway oil pool in July 1998.

Of the 38 wells that penetrate the injection horizon within the limits of the Halfway K pool (Figures 97 and 98a), 13 wells currently produce oil from the Halfway Formation. An additional two wells produce from the overlying Gething Formation and the underlying Doig Formation, respectively.Therefore, a portion of the injected acid gas is most likely produced back through the active oil wells. The production wells, as long as they are active, represent fluid sinks, ensuring that the injected acid gas does not migrate beyond the pool boundaries. Fifteen wells in the Halfway K pool are abandoned, 5 wells suspended, 2 wells categorized as “miscellaneous”, and one well disposes of water into the Halfway Formation. Upward leakage along boreholes is improbable because the Halfway K pool is underpressured with respect to the overlying formations and the potential for vertical flow is towards the injection zone. In addition, wells were drilled and abandoned in the 1980s or later (Figures 98a, b) when more stringent

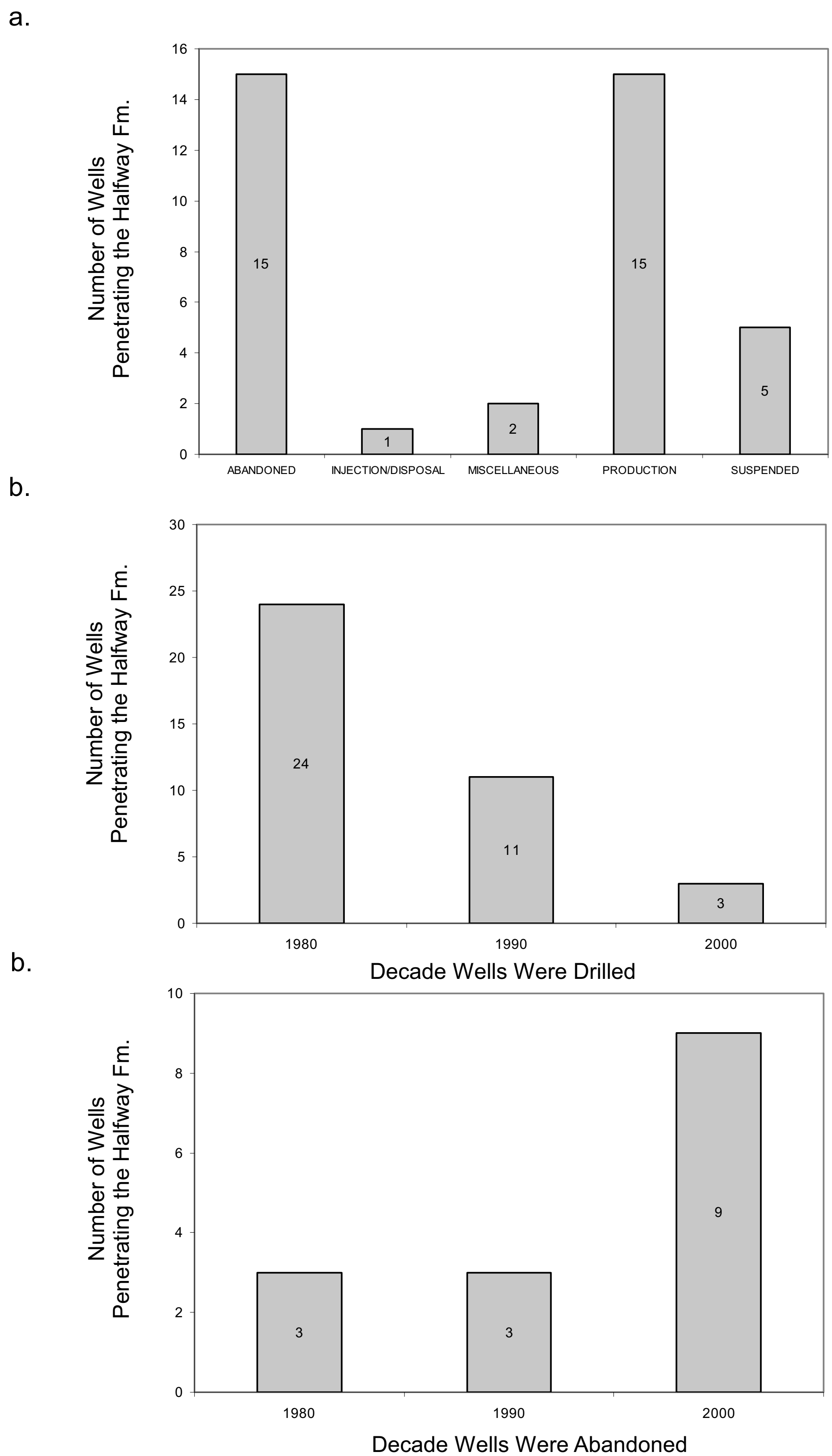


Figure 98. Histograms for wells that penetrate the Halfway Formation in the Gordondale-Halfway K pool showing: a) well status, b) time of drilling, and time of abandonment.

completion and abandonment guidelines were in place. There are no known faults in the area of the Gordondale Halfway K pool that provide a leakage path for injected acid gas into overlying strata.

6.2 Injection of Acid Gas into Regional Aquifers

Dry acid gas is injected into the Belloy aquifer at Gordondale, Mulligan, Pouce Coupe and Wembley, and into the underlying Kiskatinaw aquifer at Rycroft. The fate of the injected acid gas is controlled by the in-situ properties of the gas and formation water. Table 24 presents the density and viscosity of the injected acid gas and formation water calculated for the initial in-situ conditions given in Table 22 (Adams and Bachu, 2002; Bachu and Carroll, 2004). The density contrast between the injected acid gas and formation water varies from approximately 1:1.7 to 1:2, and the viscosity contrast varies correspondingly from 1:8 to 1:12.

Table 24. Properties of native fluids and injected acid gas at in-situ conditions at the five operations in the Peace River Arch area where acid gas is injected into aquifers.

Fluid Property	Gordondale (Belloy)	Mulligan	Pouce Coupe	Rycroft	Wembley
ρ (kg/m^3)	1084	1114	1048	1118	1107
μ (mPa s)	0.50	0.63	0.44	0.61	0.48
ρ_{ag} (kg/m^3)	570	583	633	640	572
μ_{ag} (mPa s)	0.051	0.052	0.057	0.064	0.056

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 as ρ_0 (Bachu, 1995b):

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

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, 1995b):

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

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:

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

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:

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

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 largely 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 acid gas in the subsurface have shown that the maximum distance of plume migration is in the order of five kilometres (Ozah *et al*., 2006).

In the following sections, 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, faults, 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, 2002), the density values presented in Table 24 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 24. Therefore, the density contrast between acid gas and formation water will be largest outside the pressure cone of the injection well and using these values provides a conservative estimate of the buoyancy forces acting on the acid gas.

The average injection rates at surface pressure/temperature conditions to the end of 2005 were ~35,000 m^3/day at Gordondale-Belloy, ~8,900 m^3/day at Mulligan, 18,000 m^3/day at Pouce Coupe, ~8,100 m^3/day at Rycroft, and ~66,000 m^3/day at Wembley.Considering full saturation in the regions occupied respectively by the injected gas and formation water (i.e., $k_{rb}=k_{rag}=1$), values of $\Gamma = 0.27$, $\Gamma = 0.87$, $\Gamma = 0.09$, $\Gamma = 1.1$ and $\Gamma = 0.02$, respectively are calculated (Equation 3, Table 25).

Table 25. Injection characteristics of acid-gas injection operations in aquifers.

	Q (m^3/day)	V_{max} in-situ ($10^3 m^3$)	Γ	R_{max}(m)	R_{op} (m)
Gordondale-Belloy	35000	785	0.27	1300	2000
Mulligan-Belloy	8900	170	0.87	335	390
Pouce Coupe-Belloy	18000	400	0.09	910	2100
Rycroft-Kiskatinaw	8100	480	1.1	740	780
Wembley-Belloy	66000	2800	0.02	1600	3000

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; R_{op} = radius of influence gas plume given by operator.

Injection hydrodynamics and viscous forces dominate in the cases of acid gas injection at the Gordondale-Belloy, Pouce Coupe and Wembley sites and Equation 4 will give an accurate estimate of the maximum plume spread. Relatively low injection rates at Rycroft and Mulligan 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*., 2004). 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 335 m to 1600 m. In all cases, the herein calculated radii of plume spread are less than the values given by the respective operators in their application for acid-gas injection. 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 Gordondale – Belloy

Injection of acid gas into the Belloy Formation at Gordondale commenced in June 1998, replacing injection into the Halfway K pool (see Section 6.1.6).Approximately 105 million cubic metres of acid gas (40 % of the approved volume) have been injected by the end of 2006.

In the vicinity of the Gordondale injection site the hydraulic gradient in the Belloy aquifer is approximately ∇H_0 = 0.07 % (0.7 m/km) at 17° to the northwest (Figure 99). The slope of the top of the aquifer is∇E = 1.4 % (14 m/km) at 45° to the northeast. Considering the density contrast between the injected acid gas and formation water (Table 24), the driving force ratio (DFR) is 10.2, indicating that buoyancy is significantly stronger than the natural hydrodynamic drive in the aquifer. As a result, the plume of acid gas will migrate to the northeast at approximately 34°. On the basis of the permeability and porosity values for the Belloy aquifer (Table 21) and of acid-gas and brine properties (Table 24), 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 11 m/year or less (Figure 99), depending on relative permeability of acid gas k_{rag}.

The hydrogeological assessment has shown that there is clear hydraulic separation between the Belloy and Halfway-Doig aquifers due to the thick intervening Montney aquitard. Leakage along faults is not likely because faults in the area have not significantly displaced the Montney aquitard. The only fault in the potential migration path of the acid gas is located 10 km away from the injection well.

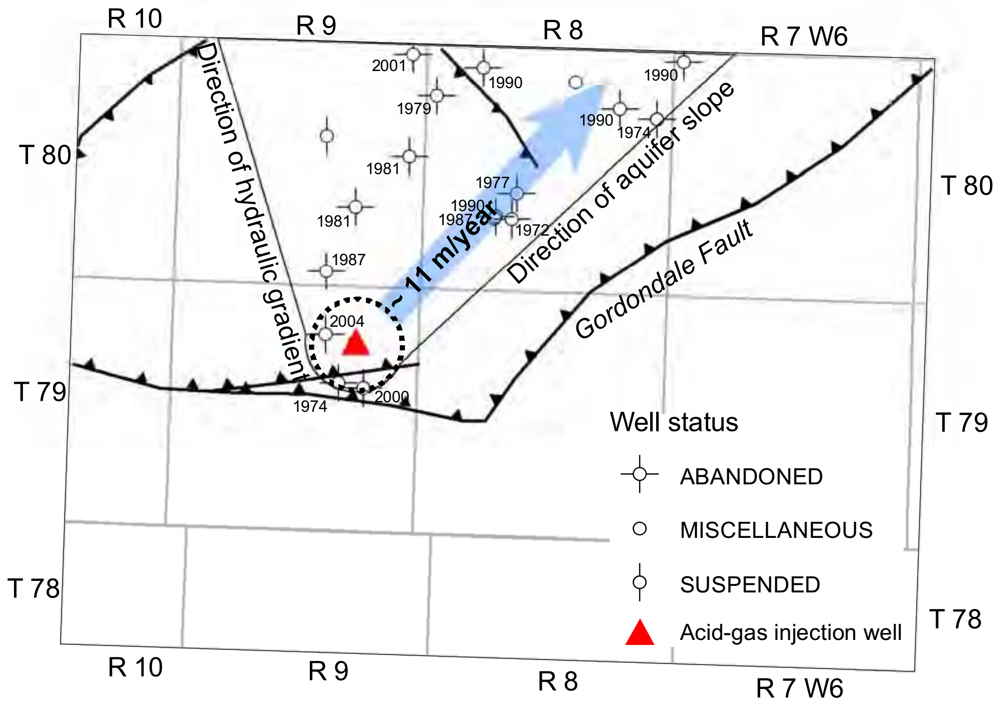


Figure 99. Assessment of long-term acid-gas migration at Gordondale-Belloy, showing location and status of wells along the potential migration path. The blue arrow represents the inferred flow direction of separate-phase acid gas as a result of the vectorial summation of buoyancy and hydrodynamic drive (Equation 1).

Wells that penetrate the injection horizon along the potential flow path of the acid gas in the Belloy aquifer (Figure 99) represent possible leakage conduits to overlying formations and, ultimately, to the ground surface. Figure 100 shows histograms of status, age, and time of abandonment for these wells. The 19 wells were drilled over a long time period starting in the 1960s and the majority were either abandoned or suspended. The older the wells and the earlier the time of abandonment, the higher is the potential for cement or casing degradation or the insufficient abandonment.Therefore, particularly the four wells abandoned in the 1970s (Figure 99) might require a follow up investigation.

6.2.4 Mulligan

At Mulligan, approximately 31 million cubic metres of acid gas acid gas (53 % of the approved volume) have been injected into the Belloy aquifer between June 1994 and the end of 2006. Similar to the Gordondale area, the Belloy Formation in the Mulligan area forms a contiguous aquifer, which is confined by thick shales of the overlying Montney Formation.

In the vicinity of the Mulligan injection site the hydraulic gradient in the Belloy aquifer is approximately $\nabla H_0 = 0.07$ % (0.7 m/km) at 25° to the northeast (Figure 101). The slope of the top of the aquifer is∇E = 1.1 % (11 m/km) at 65° to the northeast. Considering the density contrast between the injected acid gas and formation water (Table 24), the driving force ratio (DFR) is 7.0, indicating that buoyancy is significantly stronger than the natural hydrodynamic drive in the aquifer. As a result, the plume of acid gas will migrate generally to the northeast at 62°, slightly re-directed and sub-parallel to the unnamed fault in the centre of the study area. On the basis of the permeability and porosity values for the Belloy aquifer (Table 22) and of acid gas and brine properties (Table 24), an order-of-magnitude analysis shows a.

b.

c.

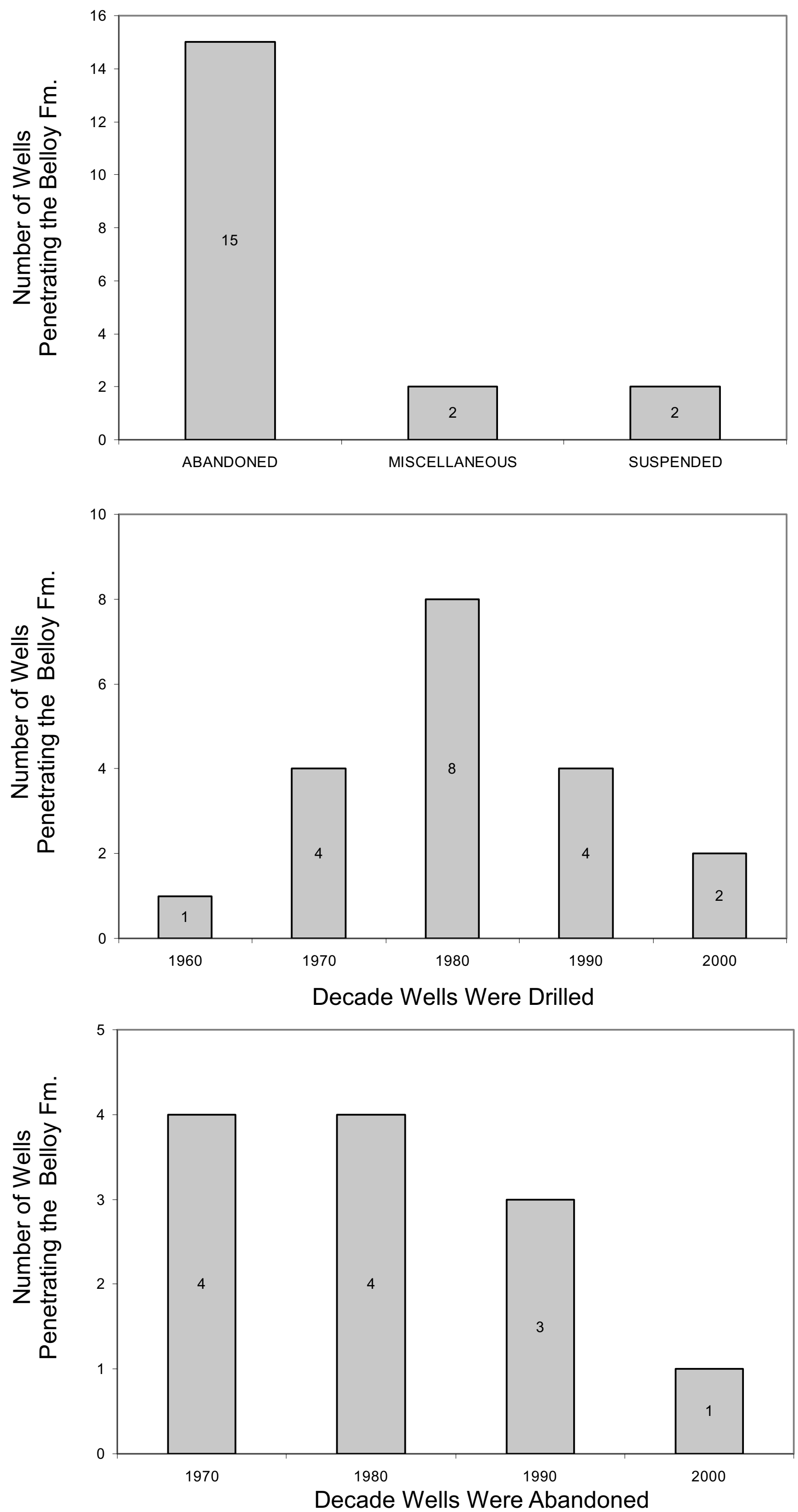


Figure 100. Histograms for wells that penetrate the Belloy Formation in the Gordondale area along the potential acid-gas migration path showing: a) well status, b) time of drilling, and c) time of abandonment.

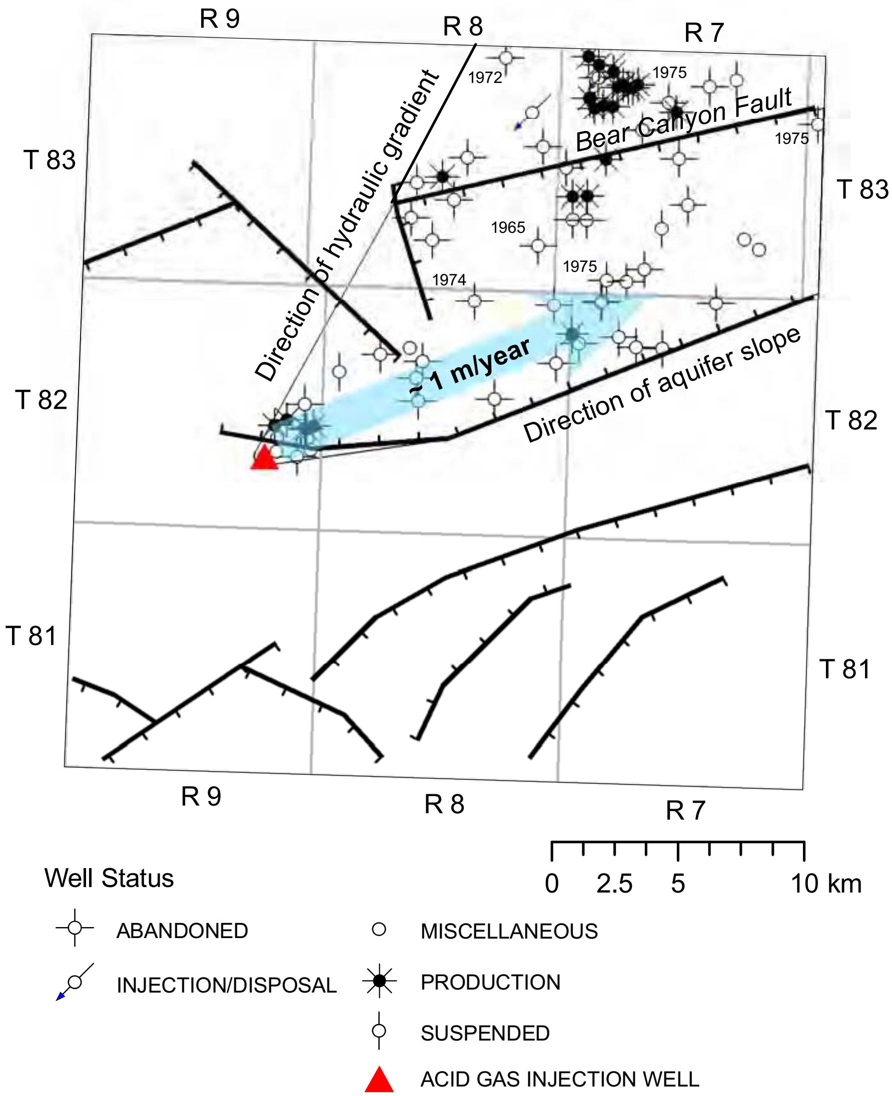


Figure 101. Assessment of long-term acid-gas migration at Mulligan, showing location, status and year of abandonment (before the 1980s) of wells along the potential migration path. The blue arrow represents the inferred flow direction of separate-phase acid gas as a result of the vectorial summation of buoyancy and hydrodynamic drive (Equation 1).

that, once outside the cone of influence around the injection well, the velocity of the updip migrating acid gas is 1 m/year or less (Figure 101), depending on relative permeability of acid gas k_{rag}.

Leakage along faults is not likely because faults in the area have not significantly displaced the Montney aquitard. However, the faulting caused the deformation of the structure top of the Belloy aquifer, resulting in the northeast-channelling of flow sub-parallel to the faults.

Figure 102 shows histograms of status, age, and time of abandonment for wells that penetrate the injection horizon along the potential flow path of the acid gas in the Belloy aquifer. Seventy-six wells, the earliest drilled in 1965, penetrate the injection horizon along the potential flow path of the acid gas (Figures 101 and 102), which represent possible leakage conduits to overlying formations. More than

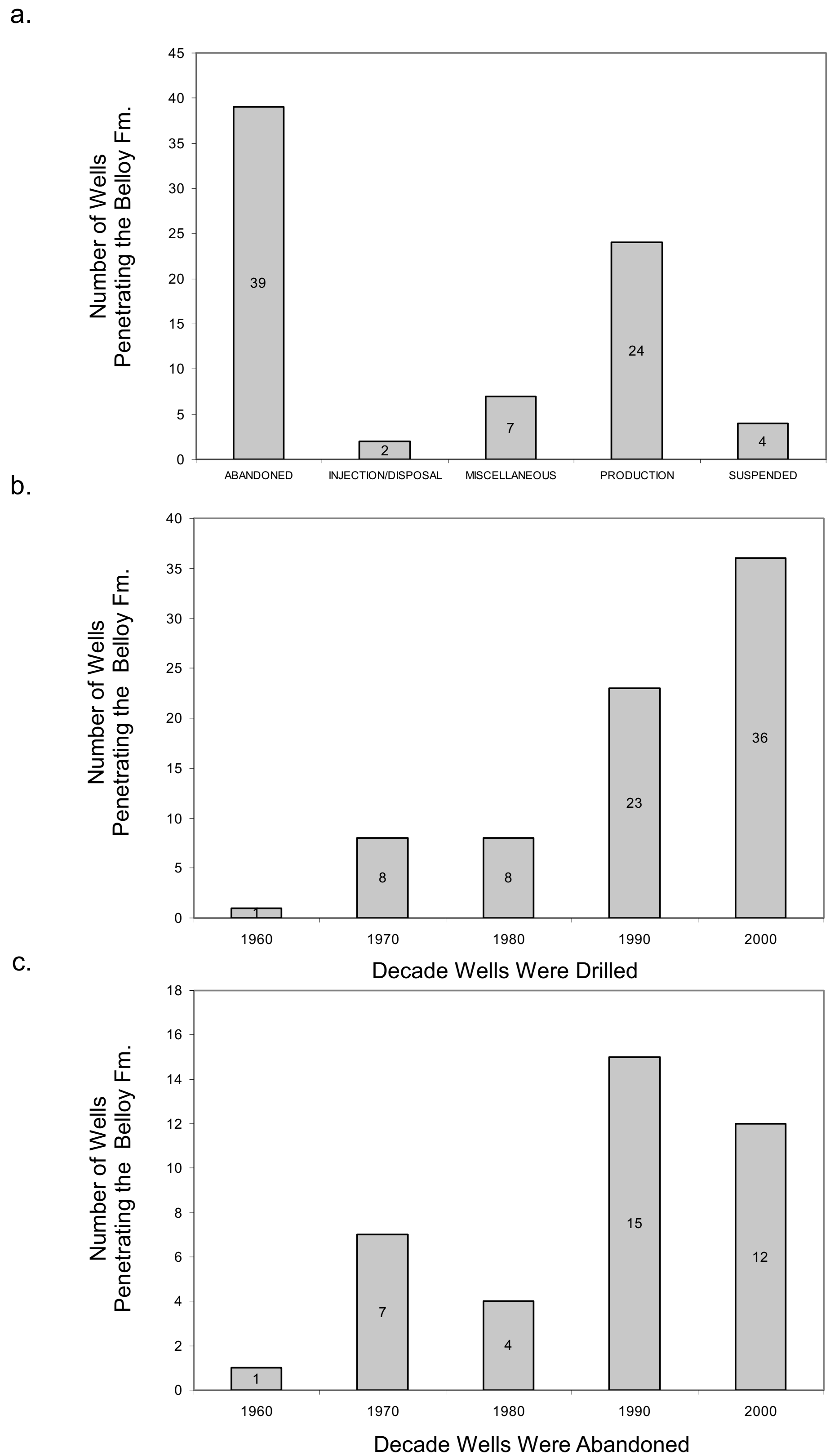


Figure 102. Histograms for wells that penetrate the Belloy Formation in the Mulligan area along the potential acid-gas migration path showing: a) well status, b) time of drilling, and c) time of abandonment.

half of the wells were abandoned (39) or suspended (4) (Figure 102). Most of the 24 production wells are completed in overlying Triassic formations. Only the four wells located approximately 1.5 km northeast of the injection well produce gas from the underlying Kiskatinaw Formation. Pressure differences between the Kiskatinaw and Belloy formations suggests that the intervening Taylor Flat Formation prevents cross-formational flow and there is no indication for hydraulic communication along the fault 600 m northeast of the injection site. The relatively young age and recent abandonment time of the majority of wells, indicate that well and borehole integrity are probably not compromised. However, the few wells abandoned in the 1960s and early 1970s (Figure 101) might have a higher potential of leakage.

6.2.5 Rycroft

Acid-gas injection into the Kiskatinaw Formation at Rycroft commenced in June 2001. A total volume of 13 million cubic metres of acid gas (7 % of the approved volume) had been injected by the end of 2006.

Although a package of siltstones, shales and tight carbonates overlie the Kiskatinaw sandstones in the Rycroft area, the hydrogeological assessment indicates the possibility of cross-formational hydraulic communication between the Kiskatinaw and Belloy aquifers. Also, the injection well previously underwent fracture treatment and the directly overlying shale cap rock in the upper parts of the Kiskatinaw Formation might be compromised. Leakage along faults is not likely because faults in the area have not significantly displaced the strata in the area (Figure 54).

Formation water flow in the Kiskatinaw aquifer at the Rycroft site is towards the north-northeast at 5° (Figure 103), with a hydraulic gradient ∇H_0 = 0.06% (0.6 m/km). The slope of the aquifer is∇E = 1.1% (11 m/km) at 52° to the northeast. Buoyancy is the dominant flow-driving mechanism for acid gas migration (DFR = 7.6), and the flow direction of the acid gas plume will be approximately 50° to the northeast, at a velocity in the order of 2.5 m/year.

Fifty-three wells, the oldest two drilled in the 1950s, penetrate the injection horizon along the potential flow path of the acid gas in the Kiskatinaw aquifer (Figures 103 and 104), and represent possible leakage conduits to overlying formations. Figure 104 shows the well statistics with respect to status, age, and time of well abandonment. The nearest production from the injection horizon occurs from Kiskatinaw pools in the Shane field, approximately 18 km northeast of the injection site (Figure 103). Considering the low migration velocity, the injected acid gas most likely will not reach these production wells. Two wells (2/14-2-77-4W6 and 2/16-2-77-4W6), currently producing oil from the overlying Belloy Formation, are located at the edge of the radius of influence of the acid-gas well. These two wells started production in 2002 and 2006, respectively, following the commencement of acid-gas injection. Low-permeability sediments in the intervening Taylor Flat Formation and in the upper part of the Kiskatinaw Formation locally separate the producing Belloy Formation from the injection interval. However, the pressure draw- down induced by the production wells and the resulting vertical pressure gradient between the Kiskatinaw and Belloy formations increases the possibility of fluids breaching the aquitard and of acid gas showing up in the Belloy producers. Monitoring of the H_2S and CO_2 content in the two production wells is needed to corroborate this leakage scenario. Additional production in the near vicinity of the injection well occurs from the Rycroft-Debolt pool, underlying the injection interval. Of the 28 abandoned wells, only two had been abandoned before the 1970s (Figure 104c), when less stringent abandonment requirements were in place, which constitutes an increased potential of leakage.

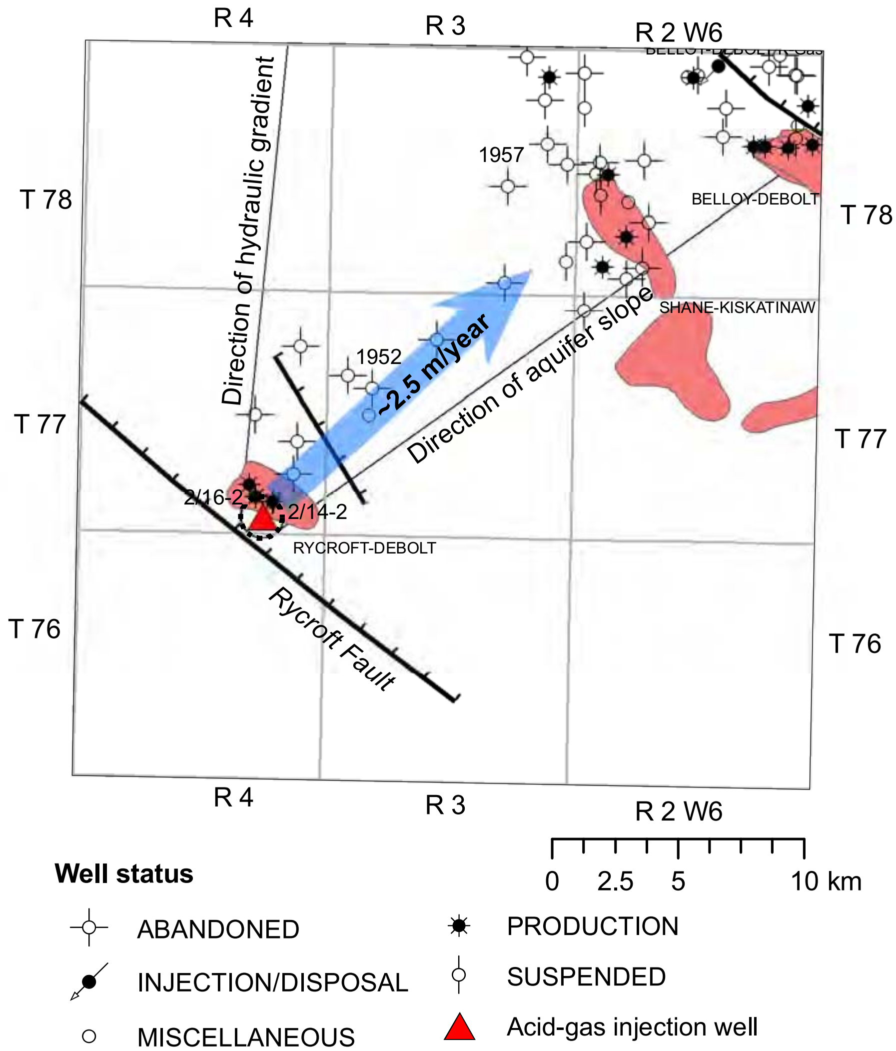


Figure 103. Assessment of long-term acid-gas migration at Rycroft, showing location and status of wells along the potential migration path. Also shown is the year of abandonment for wells abandoned before the 1970s. The blue arrow represents the inferred flow direction of separate-phase acid gas as a result of the vectorial summation of buoyancy and hydrodynamic drive (Equation 1). Also shown are gas pools (red) and producing formations.

6.2.6 Wembley

The Wembley-Belloy acid-gas operation was approved in September 2002 and started acid-gas injection in October. With an average injection rate of 65,000 m3/day and a total approved volume of 956 million cubic metres, the Wembley operation is the largest acid-gas disposal site in the Peace River Arch area. A cumulative volume of 95 million cubic metres of acid gas (10 % of the approved volume) had been injected by the end of 2006.

The local and regional hydrogeological assessment has shown that the Montney Formation forms an effective aquitard at the top of the Belloy aquifer, preventing natural vertical leakage to overlying aquifers. There are no known faults in the area of the Wembley-Belloy injection site that could provide a leakage path for injected acid gas into overlying strata.

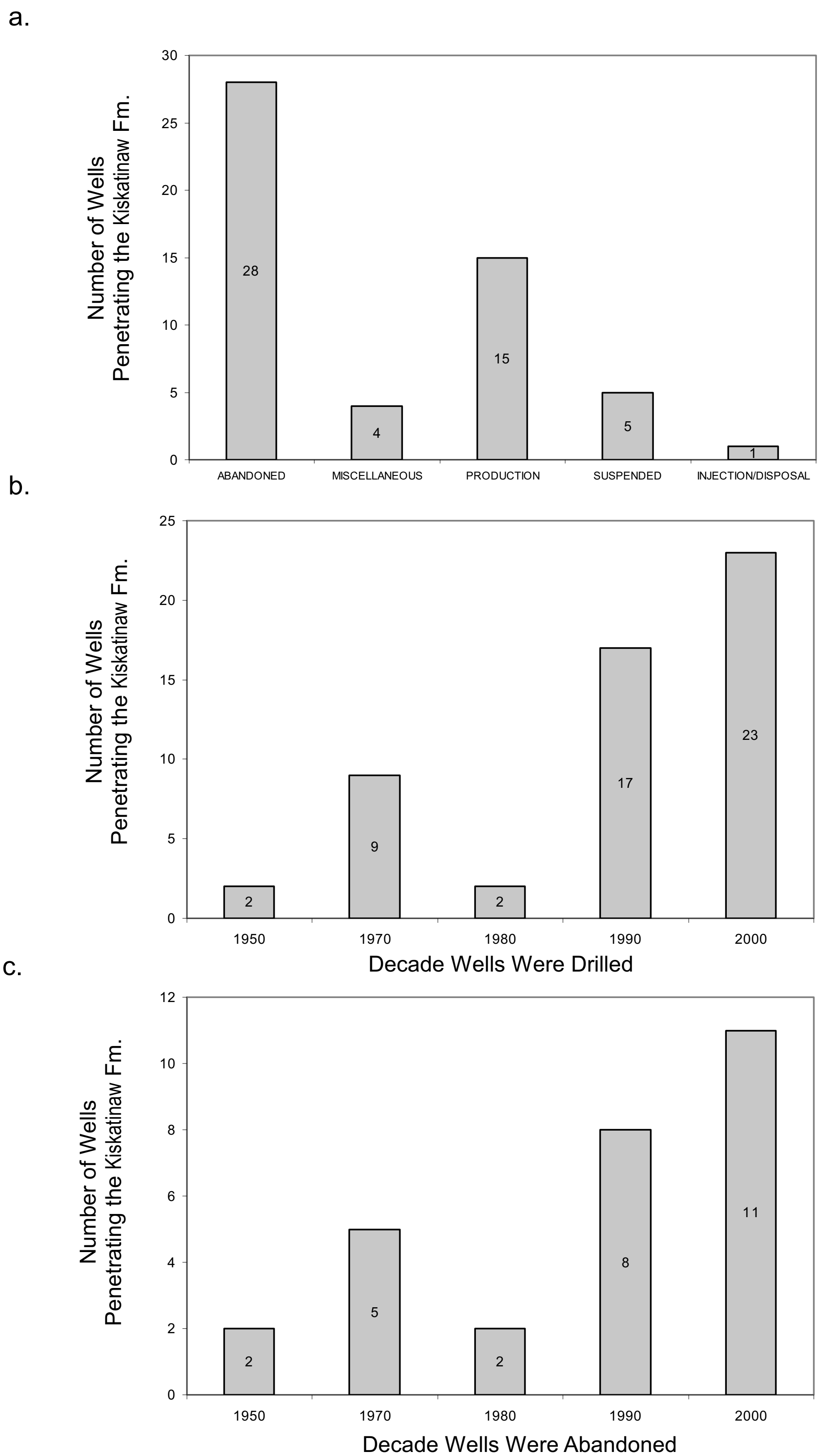


Figure 104. Histograms for wells that penetrate the Kiskatinaw Formation in the Rycroft area along the potential acid-gas migration path showing: a) well status, b) time of drilling, and c) time of abandonment.

The direction of formation water flow in the Belloy aquifer is southeastward at 150° (Figure 105), and the hydraulic gradient is ∇H_0 = 0.04% (0.4 m/km). The slope of the top of the aquifer is ∇E = 1.5 % (15 m/km) at 30° to the northeast. The DFR of 18 indicates that buoyancy is significantly stronger than the natural hydrodynamic drive in the aquifer, and acid gas will migrate dominantly northeastward at approximately 31° with a velocity in the order of 0.5 m/year (Figure 105).

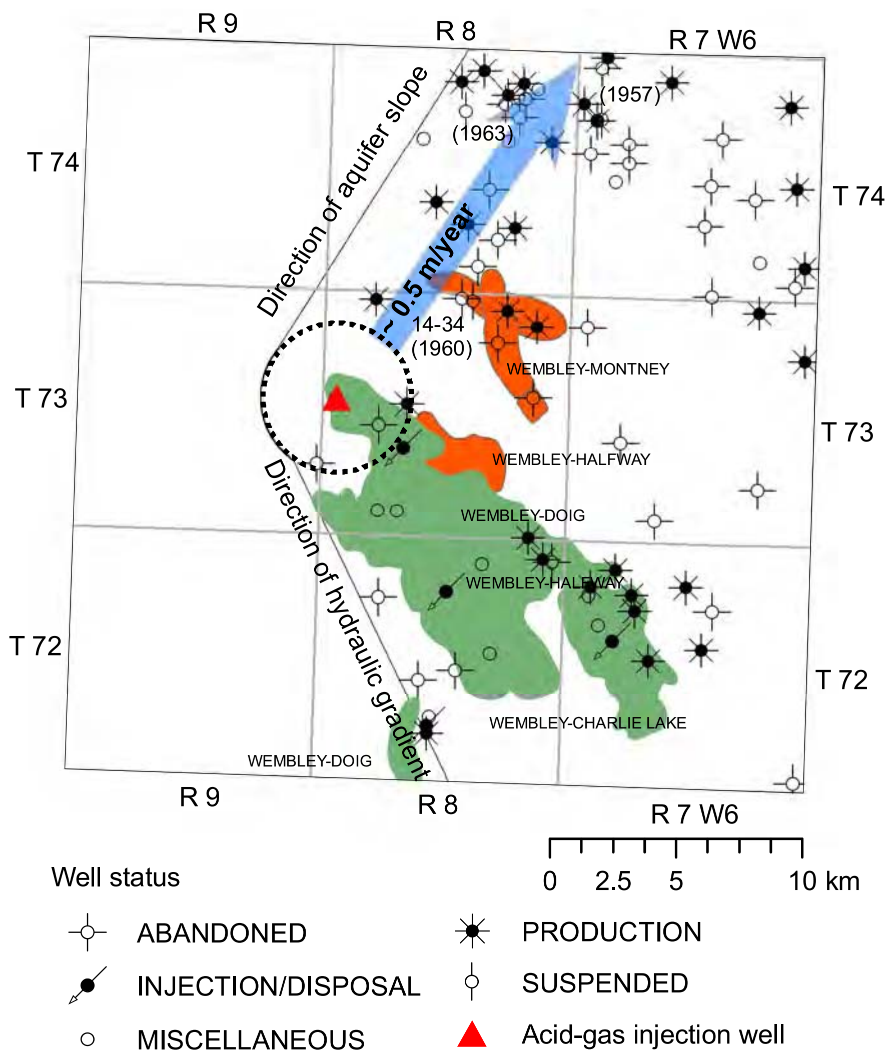


Figure 105. Assessment of long-term acid-gas migration at Wembley, showing location and status of wells along the potential migration path. The blue arrow represents the inferred flow direction of separate-phase acid gas as a result of the vectorial summation of byoyancy and hydrodynamic drive (Equation 1). Also shown are oil (green) and gas pools (red) and producing formations, and year of abandonement (in brackets) for wells abandoned before 1970.

Eighty-five wells, the earliest drilled in the 1950s, penetrate the injection horizon along the potential flow path of the acid gas (Figures 105 and 106), which represent possible leakage conduits to overlying formations. The 32 production wells are completed mostly in overlying Triassic formations. Approximately one third of the wells was abandoned (33) or suspended (3) (Figure 106a). The three wells abandoned before 1970 are of particular interest, because at that time abandonment guidelines were less stringent.According to the EUB approval for acid-gas disposal, the operator has to monitor the two production wells in the overlying Wembley-Montney pool, approximately 6.5 km updip of the injection

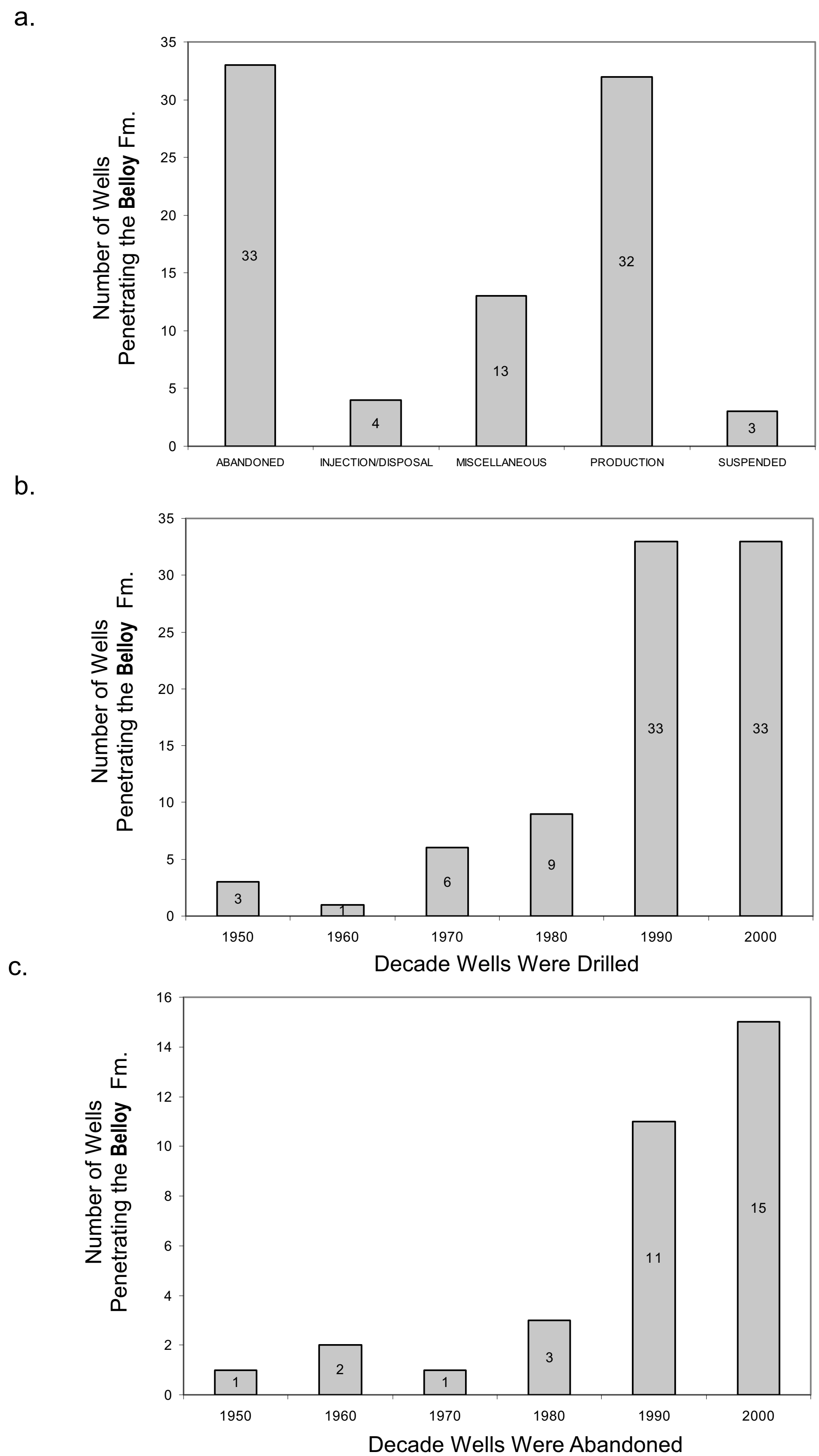


Figure 106. Histograms for wells that penetrate the Belloy Formation in the Wembley area along the potential acid-gas migration path showing: a) well status, b) time of drilling, and c) time of abandonment.

well, because the un-cased 14-34-73-8W6 well abandoned in 1960 poses a high potential of upward leakage of acid gas. However, communication of migrating acid gas with the production wells is not anticipated before 10 years after start of injection, by which time the Montney pools will be depleted.

6.2.7 Pouce Coupe

Acid-gas injection at Pouce Coupe commenced in June 1999. By the end of 2006, 46 million cubic metres of acid gas (31 % of the approved volume) had been injected into the Belloy aquifer. The local and regional hydrogeological assessment has shown that the Montney Formation forms an effective aquitard at the top of the Belloy aquifer, preventing natural vertical leakage to overlying aquifers. The Gordondale Fault, approximately 2.2 km northeast of the injection well, outside the radius of influence (Figure 107), penetrates the Montney aquitard, resulting in approximately 30 m of displacement. Considering the large thickness of the Montney Formation (300 m), the fault displacement is probably too small to compromise the aquitard integrity. The hydrogeological data suggests that the Gordondale Fault, due to the vertically displacement of the Belloy aquifer, laterally restricts fluid flow. The increase in bottomhole pressures from 20,822 kPa to 23,565 kPa between 2000 and 2005 due to acid gas injection corroborates that the Belloy aquifer might be laterally confined and that acid-gas migration is limited to within the Belloy aquifer southwest of the Gordondale Fault.

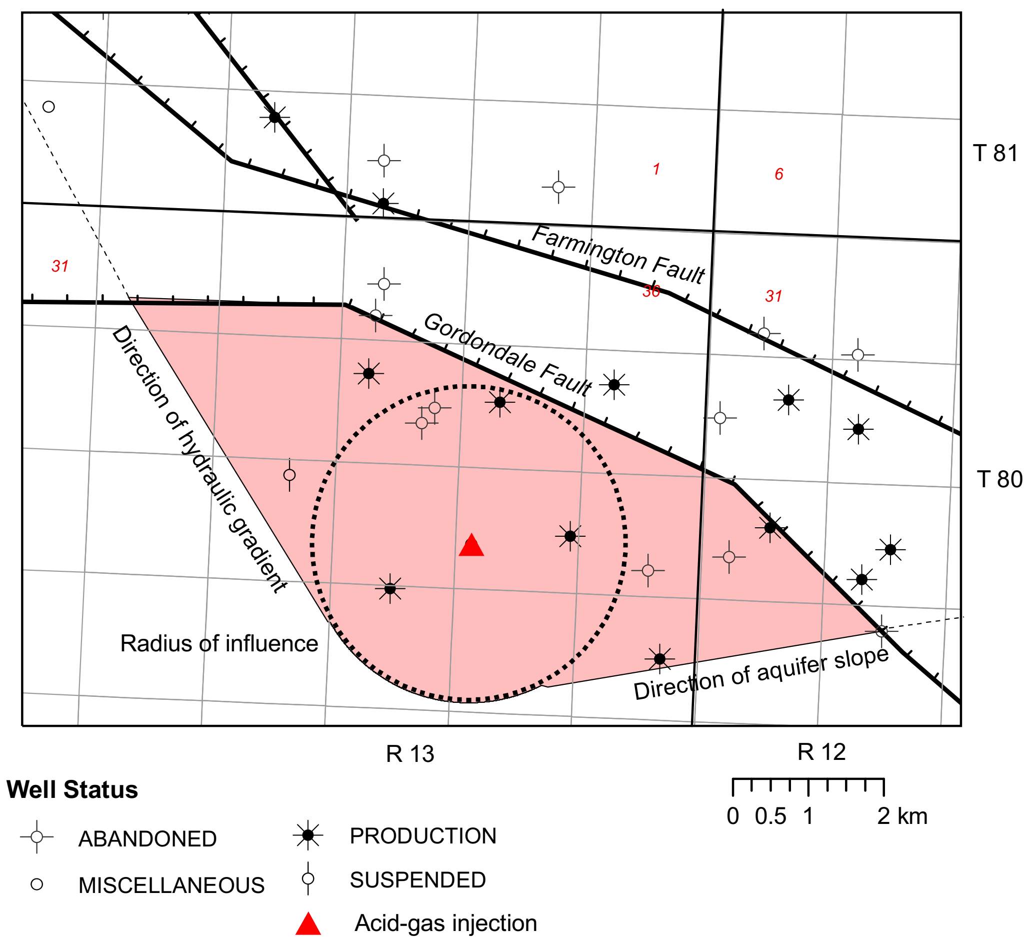
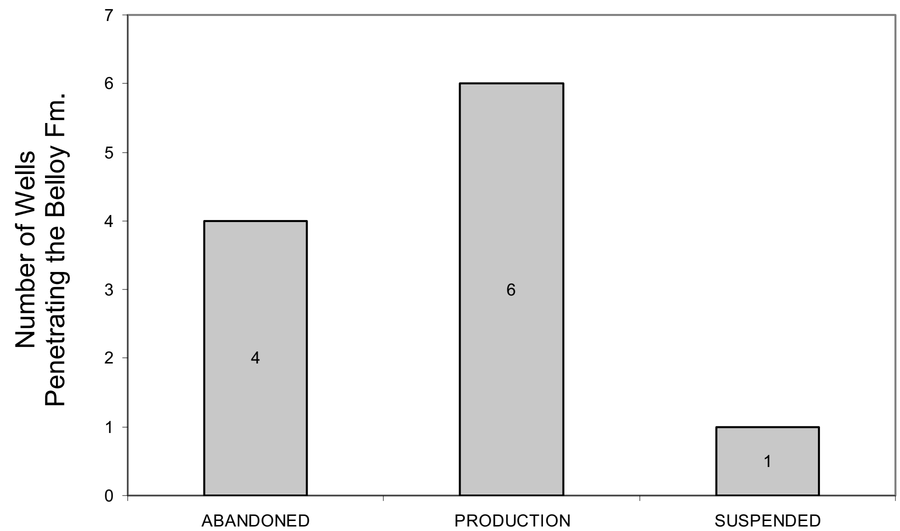


Figure 107. Assessment of long-term acid-gas migration at Pouce Coupe, showing location and status of wells within the area of influence (red) of the acid-gas injection well. Separate-phase migration of acid gas will occur as a result of the vectorial summation of buoyancy and hydrodynamic drive (Equation 1). However, migration will be limited to the area south of the Gordondale Fault, which vertically offsets the Belloy aquifer.

There are eleven well penetrating the Belloy Formation within the limits of potential acid-gas migration (Figure 108). Six wells currently produce gas from over-(Triassic) and underlying (Kiskatinaw Formation) formations, four wells were abandoned and one well is suspended. These wells were drilled between 1951 and 2005, and the abandonment of the four wells occurred between 1974 and 2005. To confirm that there is no leakage of acid-gas through well bores or faults into overlying formation, the EUB imposed on the operator of the disposal scheme the monitoring of gas compositions in offset producing wells. No increase in CO_2 or H_2S content of the produced gas has been detected to date.

a.



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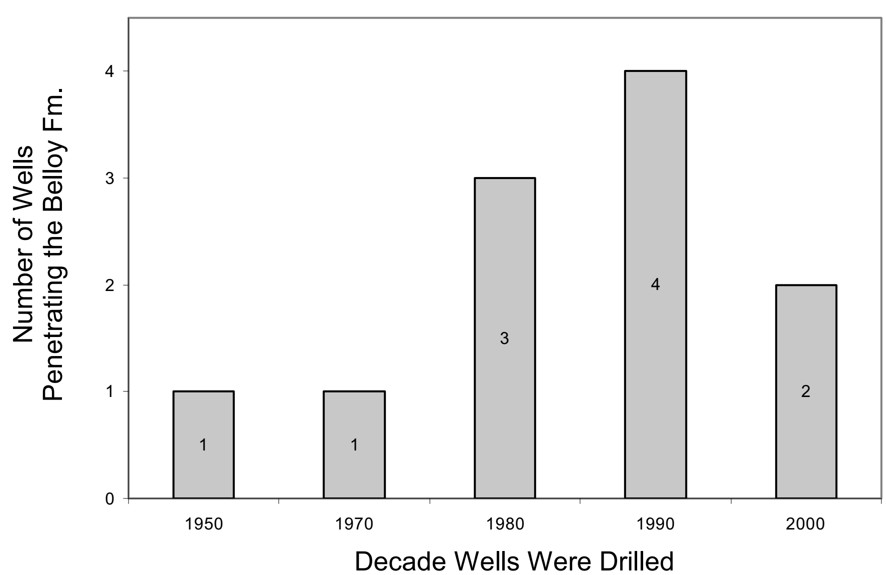

Figure 108. Histograms for wells that penetrate the Belloy Formation in the vicinity of the Pouce Coupe injection site showing: a) well status, and b) time of drilling.

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 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 the 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 eleven 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 injection at Mirage and Gordondale-Halfway, 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.

6.4 Comments on the Potential of Leakage along and across Faults

For vertical leakage along faults to occur, i.e., for faults to form flow conduits, the faults must have sufficiently high permeability to allow fluid migration. This is particularly of interest in the case where faults penetrate low-permeability strata that form barriers to fluid flow in the absence of faults. However, the permeability of faults is poorly understood and can be several orders of magnitude smaller or larger than the permeability of the undeformed rock (Scholz and Anders, 1994; Matthai and Roberts, 1996). According to Scholz and Anders (1994), two structures within fault zones influence their hydraulic properties: a) crushed rock within the fault core (cataclasite zone) and b) enhanced cracking in the rock adjacent to the fault (process zone wake). Depending on the stress regime and on whether these two zones were subsequently sealed by mineralization or clay minerals, faults could act as barriers or conduits to fluid flow. It is also possible for faults to form conduit-barrier systems, in which the fault prevents lateral flow and, at the same time, to act as a vertical flow conduit (Bense and Person, 2006).

In the Peace River Arch area, dolomitization patterns in Devonian strata suggest that faults probably have acted as vertical conduits for mineralizing fluids during Mississippian time (i.e., Packard and Pellegrin, 1989; Dix, 1993; McKenzie, 1999), when an extensional stress regime was active. However, there is no evidence for present-day vertical leakage along faults. Natural gas seeps can be found along the Peace River north of the Town of Peace River (Letourneau et al., 2001), however these have not been linked to the presence of faults.The current compressional stress regime does not favour the natural opening of faults and fractures and the mineralization and clay mineral could have contributed to the healing of faults. On the other hand, there is clear indication for faults currently acting as barriers to lateral flow based on hydrogeology (distribution of hydraulic-heads and salinity) and compartmentalization of hydrocarbon reservoirs. There is a possibility of inducing and re-activating faults due to fluid injection (Horner et al., 1994). However, this is unlikely to occur in the case of the acid-gas injection operations due to the relatively low injection rates and injection pressures lower than the fracturing pressure.

7 Conclusions and Recommendations

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 2006, close to 3.5 Mt CO_2 and 2.0 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 Peace River Arch area occurs in three major stratigraphic units, the Upper Devonian Leduc Formation and Wabamun Group, the Permo-Mississippian Belloy and Kiskatinaw formations, and the Triassic Halfway Formation. By the end of 2006, approximately 340 million cubic metres of acid gas were injected into deep geological formations in the Peace River Arch area.

If only the natural setting is considered, including geology and flow of formation waters, the regional- and local-scale hydrogeological analyses indicate that injecting acid gas into these deep geological units in the Peace River Arch area is a safe operation with minimum potential for acid-gas migration to shallower strata, potable groundwater and the surface. At Dunvegan, Eaglesham, Gordondale (Halfway), Mirage, Normandville, Parkland, and Puskwaskua, injection occurs or took place into depleted hydrocarbon reservoirs. By regulation, downhole pressures will not exceed the respective initial reservoir pressures and the injected gas will remain within the respective pool outlines. In the case of the Eaglesham North operation, new pools in the Wabamun Group were developed in the close vicinity of the injection well after acid-gas injection had started. Production from these pools should be monitored for potential breakthrough of injected acid gas. At Mirage and Gordondale-Halfway, acid gas was injected into currently producing Halfway reservoirs, which will partly be recycled in the injection/production cycle. In the cases of acid-gas injection into deep saline aquifers (Gordondale-Belloy, Mulligan, Pouce Coupe, Rycroft and Wembley), the extent and migration of the acid-gas plume will likely be limited by dissolution, dispersion, residual gas saturation and trapping along the migration pathway and therefore not reach the overlying aquifers.

The entire stratigraphic interval from the Leduc Formation to the Halfway Formation is overlain by at least one contiguous thick shale sequence, the Smoky Group. Other aquitards (i.e., Wilrich, Fernie, Charlie Lake, Montney, Banff-Exshaw) form additional barriers to acid-gas migration from the various injection zones 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 space and time scales.

Tectonics greatly affected the sedimentary framework, particularly the Paleozoic succession, in the Peace River Arch area. The main tectonic activity occurred during the late Carboniferous, resulting in thick Mississippian to Permian sediment accumulation in the area of the Dawson Creek Graben Complex. Existing hydrogeological data indicate that, under the present-day stress regime, faults present in the various local-scale study areas do not act as fluid conduits through aquitards overlying the respective injection horizons. However, the displacement of strata along faults that are present near injection wells results in a partial lateral confinement of acid-gas within injection intervals. Based on available data, it seems that there is no potential for acid gas leakage through faults and 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 Peace River Arch area has a high well density and the wells penetrate hydrocarbon-bearing strata down to the Granite Wash overlying the Precambrian basement. Wells in the Peace River Arch area were drilled, and successively abandoned, as early as the late 1950s and damage to or improper well completion is very likely, particularly in the cases of old wells. No leakage has been 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. A recent study numerically simulating 50 years of acid-gas injection (total volume: 26 billion cubic metres) into a sloping aquifer suggests that after 10,000 years the majority of the injected gas will be trapped as residual gas or in solution, limiting the lateral extent of the acid-gas plume to less than 5 km away from the injection well (Ozah et al., 2006). Injection volumes of acid gas in the Peace River Arch area are generally an order of magnitude less than was modelled in this study. Therefore, the assumption of a maximum plume radius of 5 km in the cases of acid-gas injection operations in the Peace River Arch area appears to be reasonable, even if parameters for aquifer, rock and fluid properties have a wide range. Predictive numerical models of acid-gas injection and flow should be used more regularly in the future to validate the qualitative hydrogeological analysis presented in this report. Geochemical and geomechanical effects on reservoir rock, caprock and faults should be assessed to confirm integrity. The potential for and the risk of leakage through existing wells and faults 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.

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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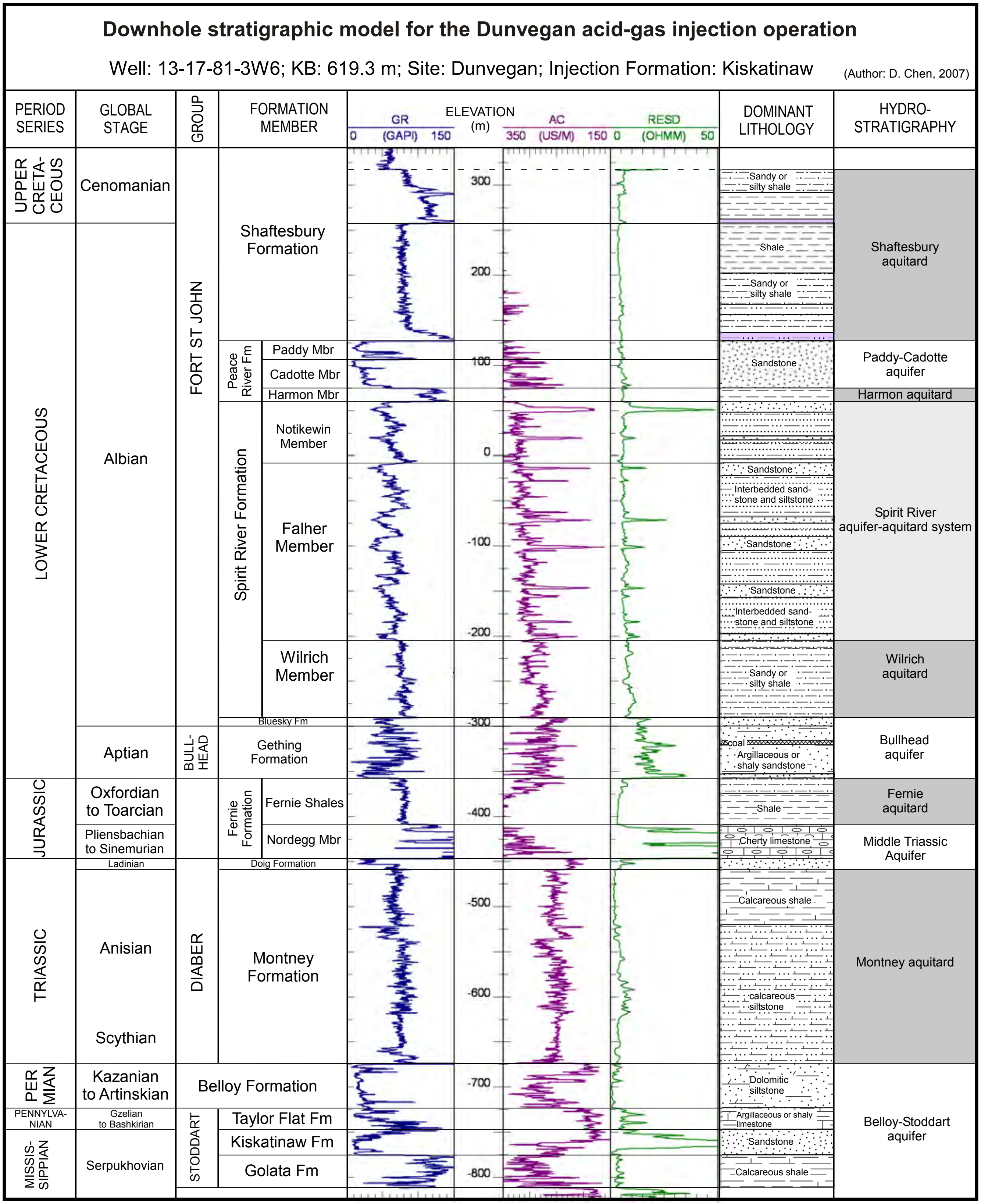
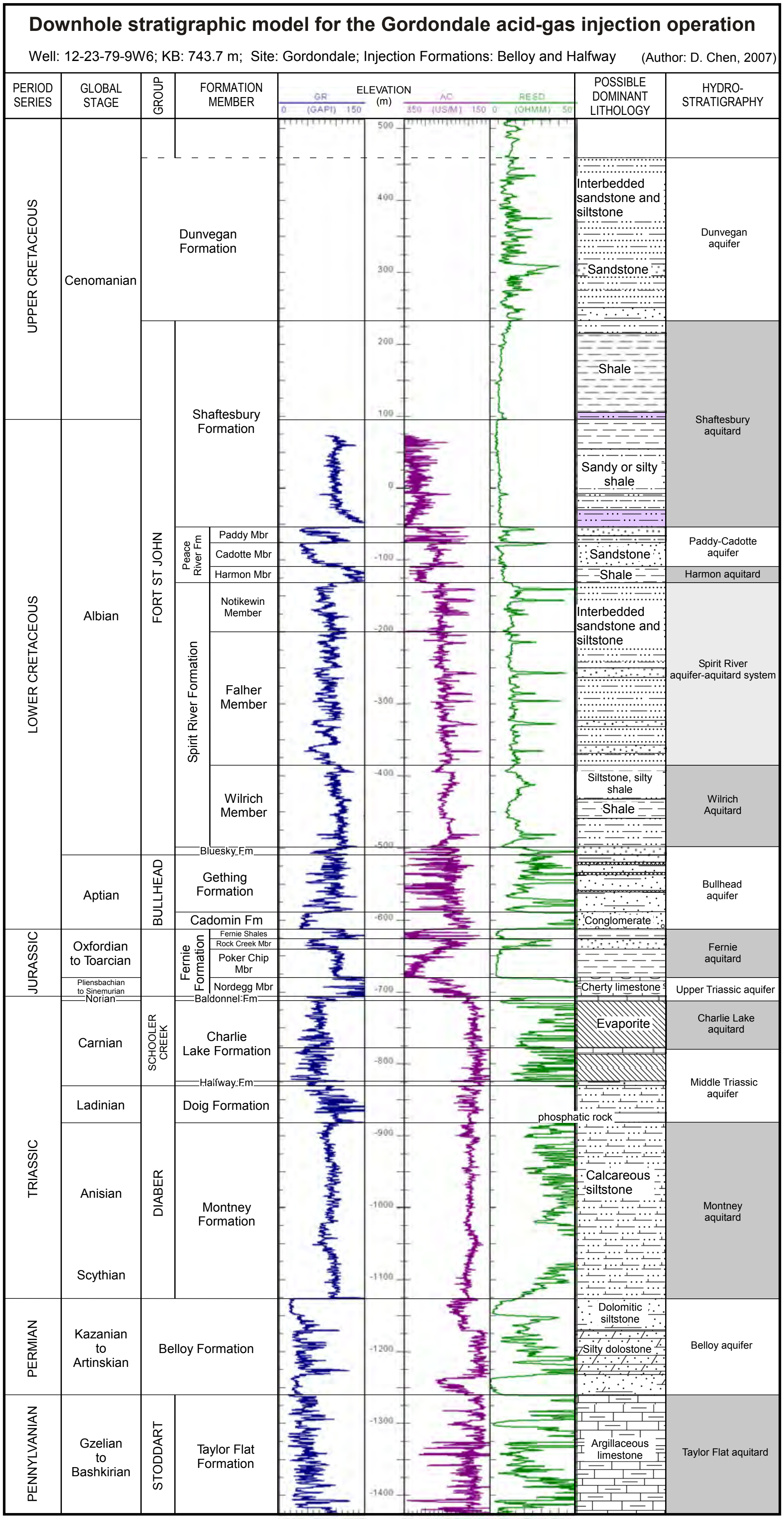
Appendix 1 - Downhole Stratigraphic Models

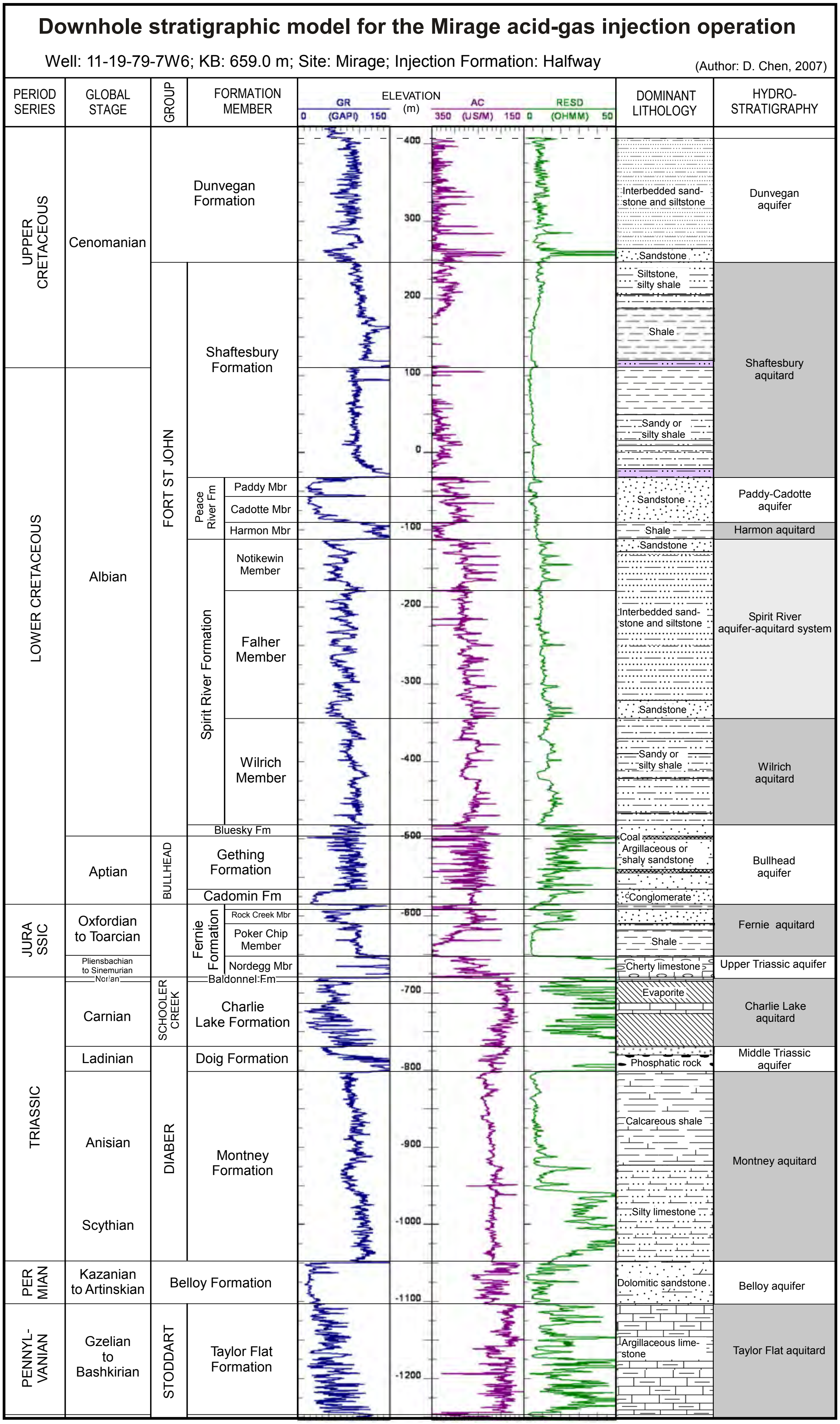
A1-1. Downhole stratigraphic model for the Dunvegan acid-gas injection site



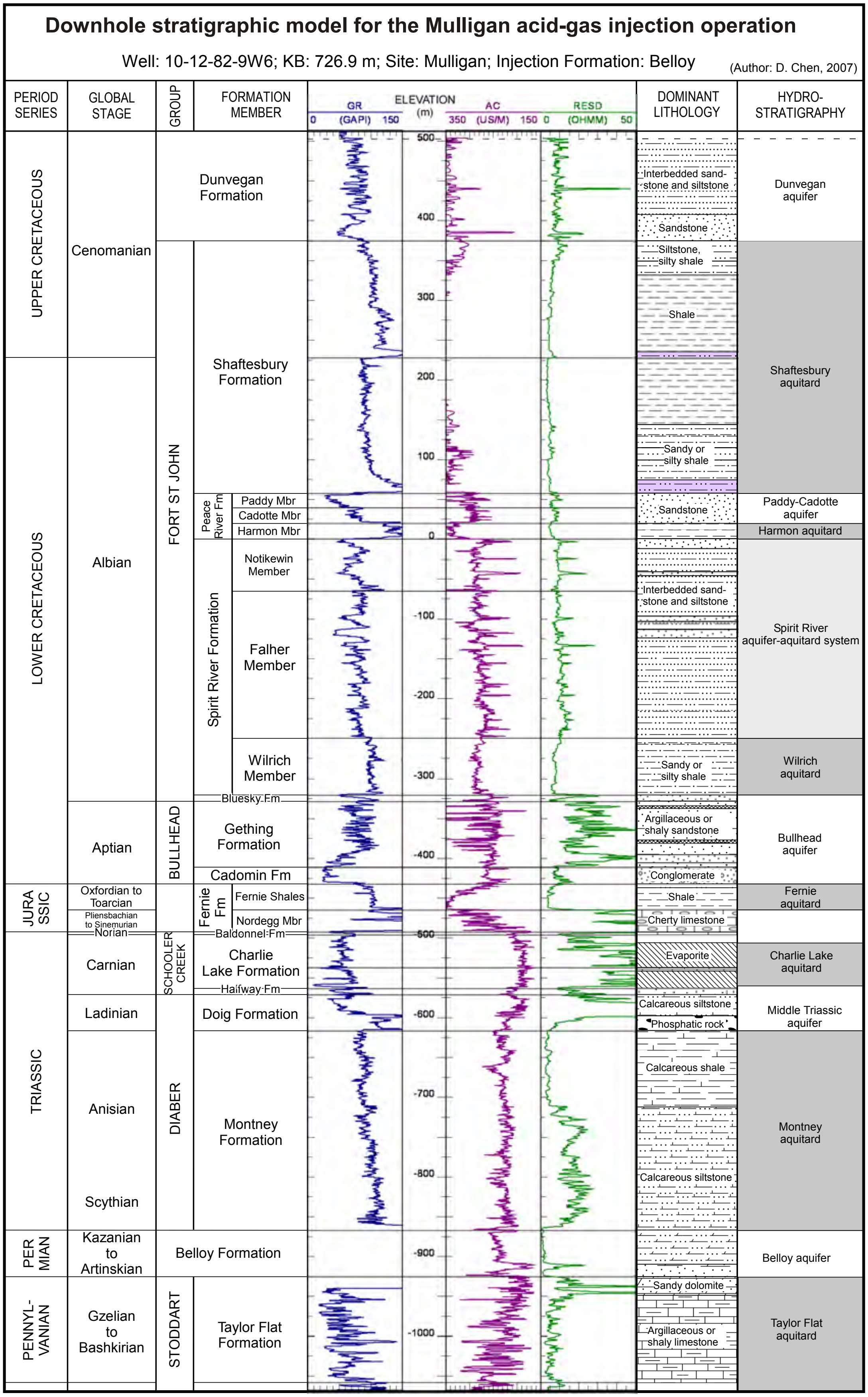
A1-2. Downhole stratigraphic model for the Gordondale area



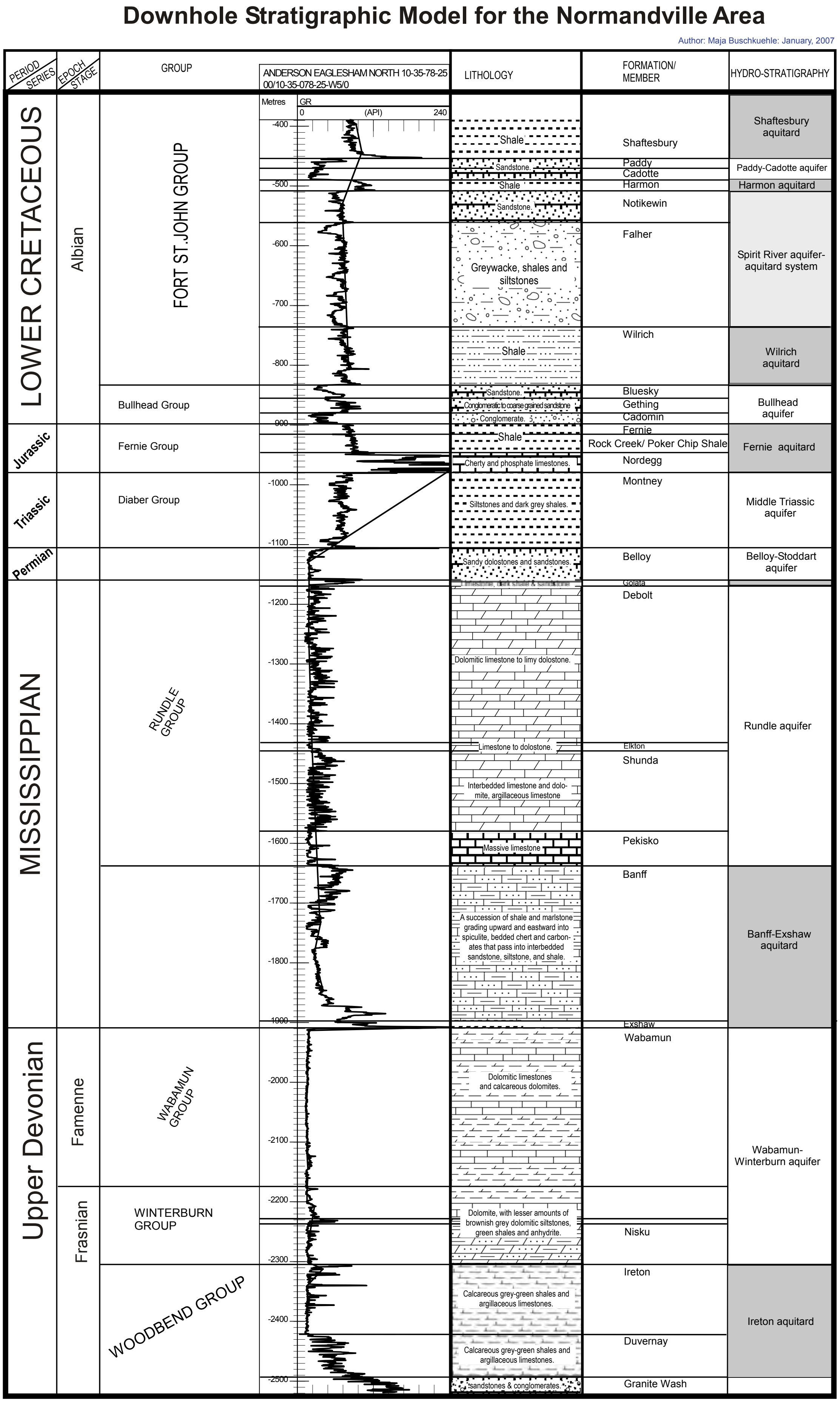
A1-3. Downhole stratigraphic model for the Mirage acid-gas injection site



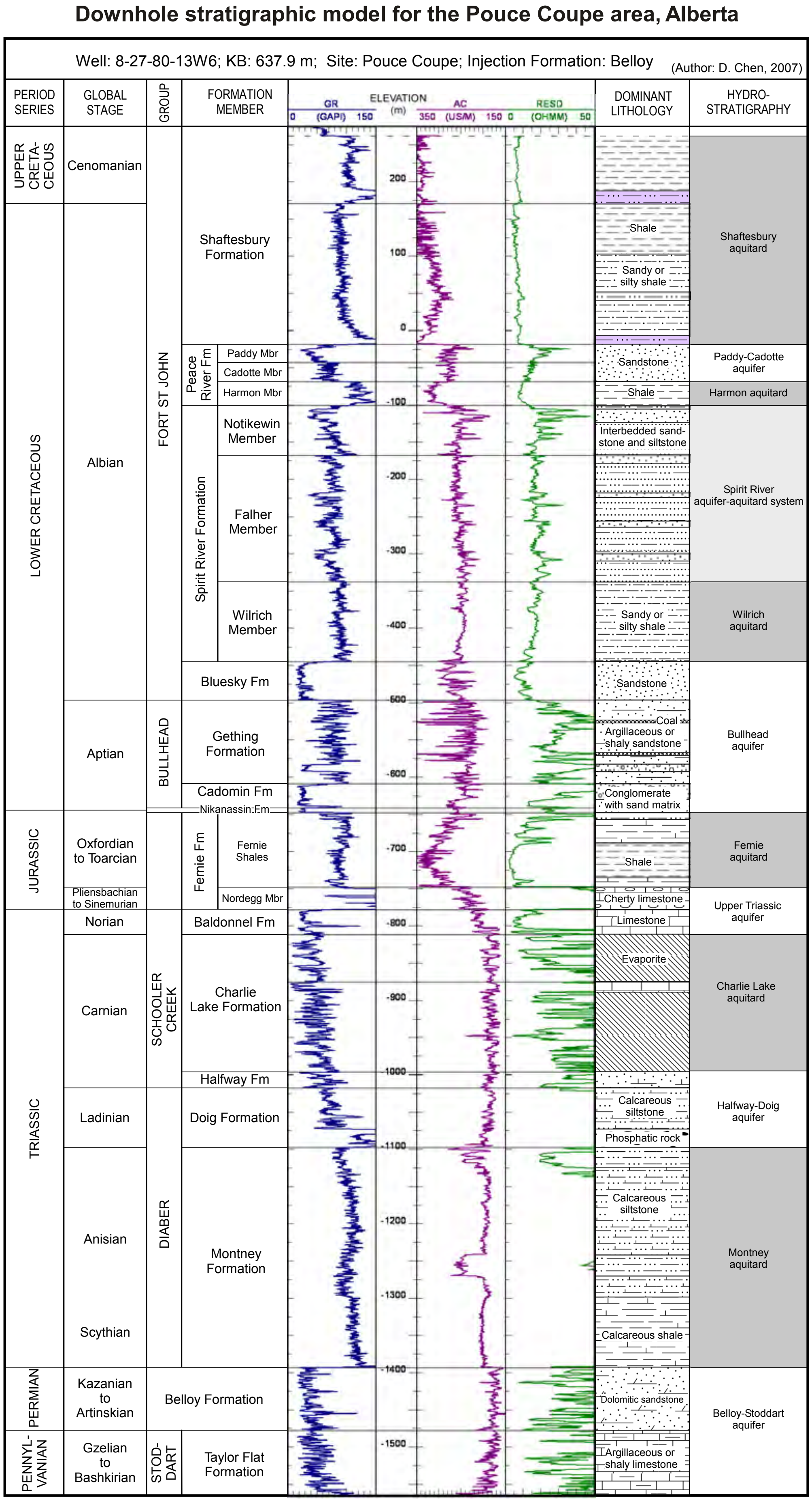
A1-4. Downhole stratigraphic model for the Mulligan acid-gas injection site



A1-5. Downhole stratigraphic model for the Normandville area



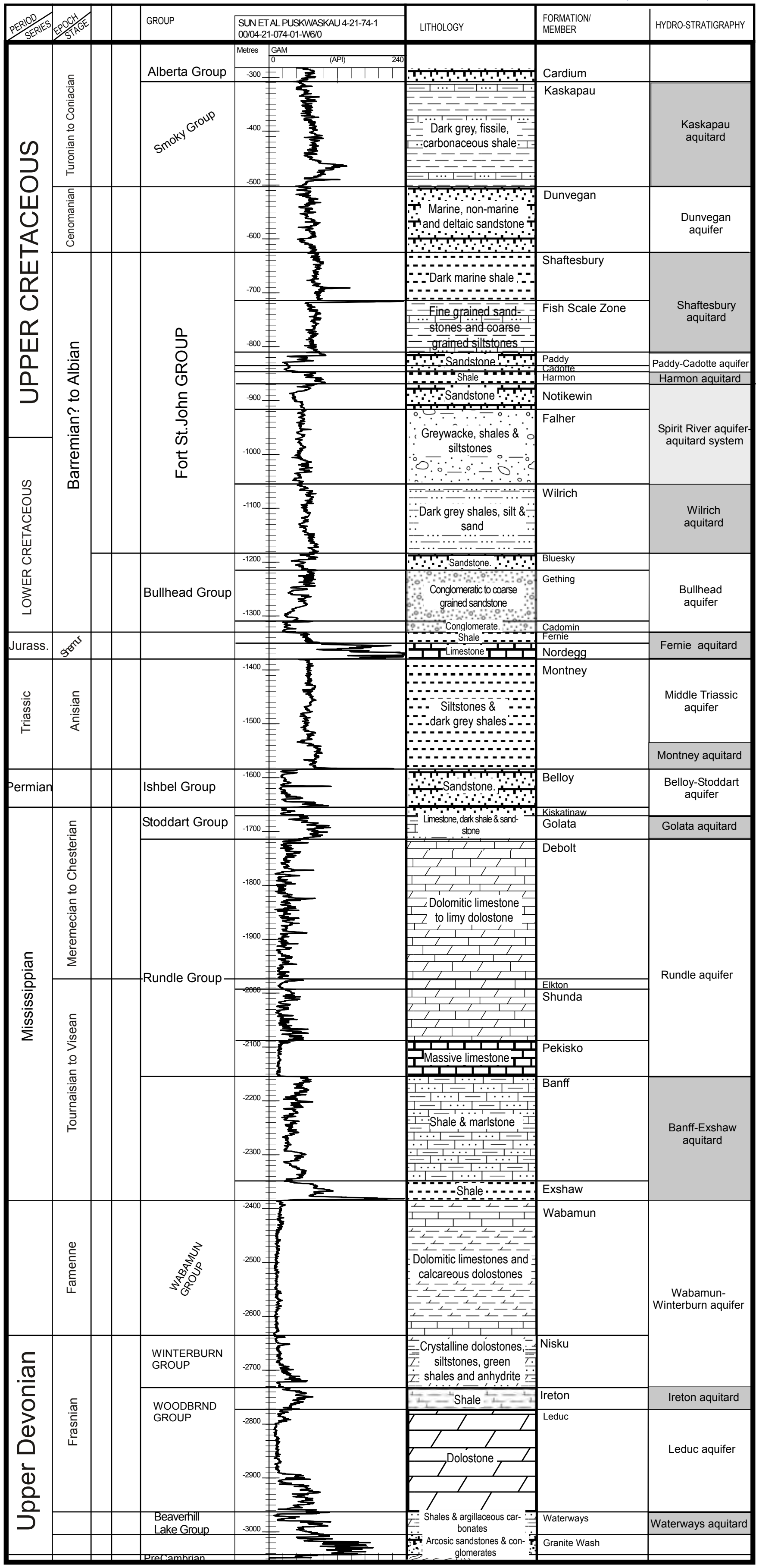
A1-6. Downhole stratigraphic model for the Pouce Coupe area



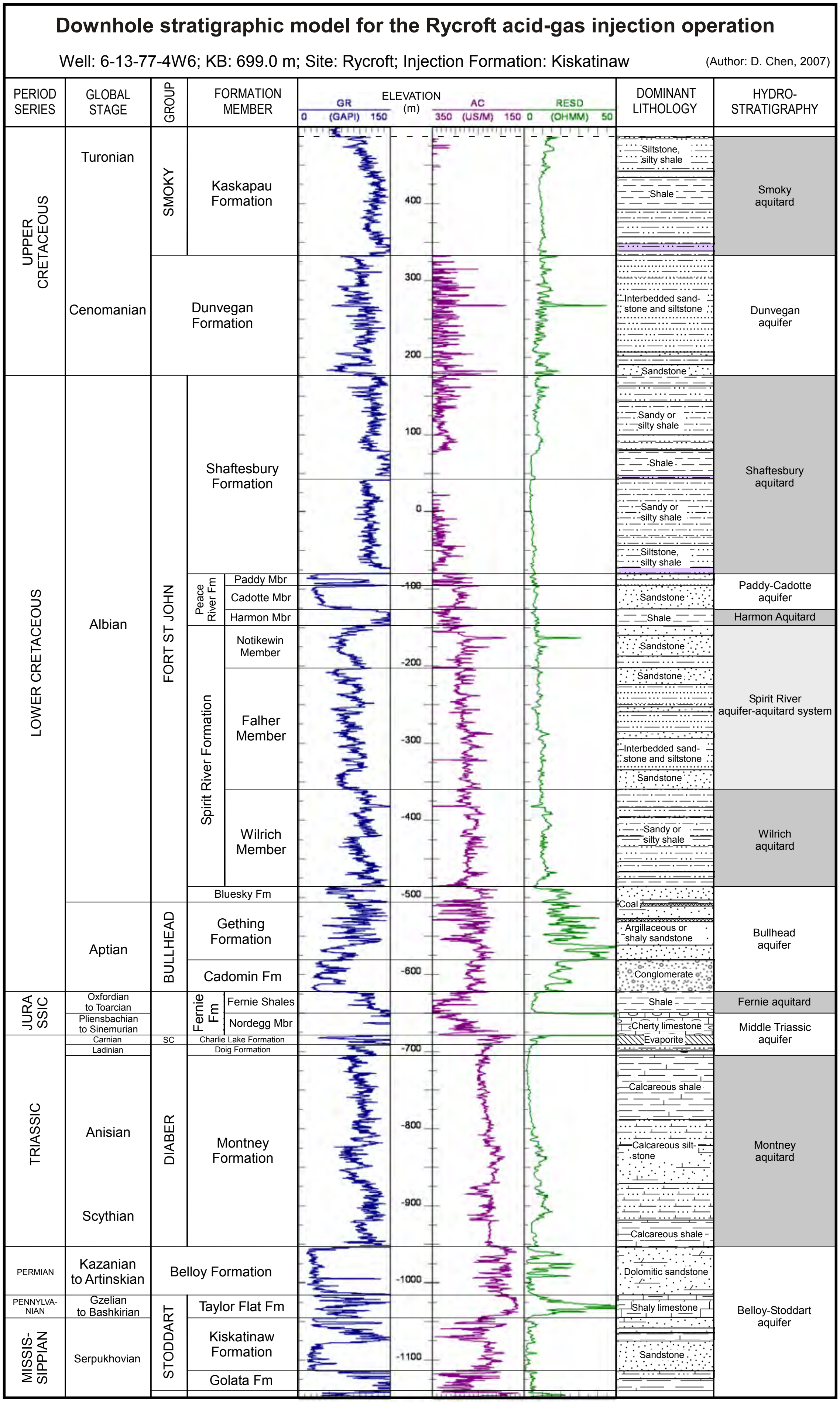
A1-7. Downhole stratigraphic model for the Puskwaskua area

Downhole Stratigraphic Model for the Puskwaskua Area, Alberta

Author: Maja Buschkuehle: January, 2007



A1-8. Downhole stratigraphic model for the Rycroft area



A1-9. Downhole stratigraphic model for the Wembley area