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Preliminary assessment of the geological potential for sequestration of CO_2 as gas hydrate in the Alberta portion of the Western Canada Sedimentary Basin

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1. INTRODUCTION

Current concern regarding the impacts of increasing levels of atmospheric carbon dioxide (CO_2) on the global climate system has provided an impetus for the development of methods for the long-term disposal of CO_2 produced by industrial activities. Alberta is considered to be a world-class candidate for geological sequestration of CO_2 because of its large areal extent and the substantial thickness of relatively porous and permeable sediments underlying much of the province. Numerous studies have been implemented to investigate possibilities for CO_2 capture and storage in geological formations such as coal and salt beds, and oil and gas reservoirs in Western Canada (e.g. Bachu, 2003; Natural Resources Canada, 2006). All of these studies have been limited to evaluating the potential to sequester CO_2 in relatively mobile gaseous or liquid phases. A somewhat novel but intriguing CO_2 storage option involves the injection of CO_2 gas into geological reservoirs suitable for the formation and long-term sequestration of CO_2 as a comparatively non-mobile solid-phase gas hydrate.

On a volume basis, CO_2 hydrate has a remarkable CO_2 storage capacity, with one volume of CO_2 hydrate containing as much as 160 volumes of free gas equivalent under standard pressure-temperature (P-T) conditions. While it is expected that conventional oilfield technologies can be utilized for CO_2 injection and monitoring of CO_2 hydrate formation in porous reservoir sediments, at present this concept is based on current theoretical understanding and limited laboratory research. Substantial research and development is needed to fully evaluate the scientific, engineering, and environmental considerations pertinent to this CO_2 sequestration option. Figure 1 presents a schematic depiction of several alternative settings for the sequestration of CO_2 as gas hydrate in Canada.

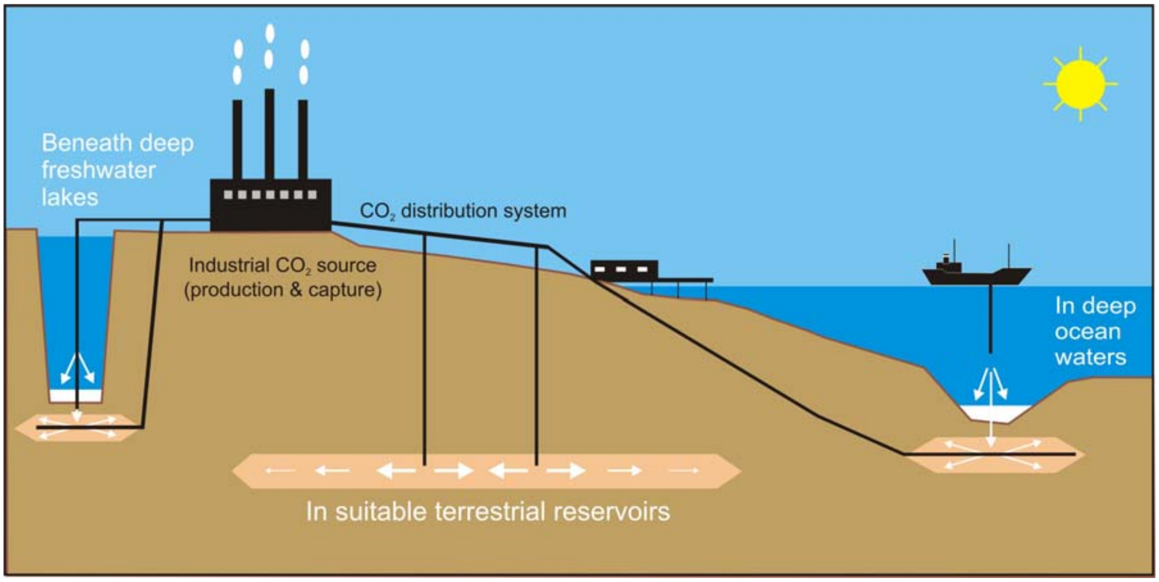

FIGURE 1. Options for geological sequestration of CO_2 as gas hydrate.

The Geological Survey of Canada (GSC), with funding support from Canada's Climate Change Action Plan (CCAP 2000), has completed a preliminary assessment of the feasibility of geologic sequestration of CO_2 as a solid-phase gas hydrate in candidate geologic reservoirs in Canada. The research consisted of a number of different components, including:

1. Fundamental research into CO_2 hydrate formation and stability in porous media.
2. Assessment of regional opportunities for the geological sequestration of CO_2 as gas hydrate.
3. Review of conventional oil field technologies and methods, and their suitability for CO_2 sequestration applications, including monitoring of reservoir responses to CO_2 injection and hydrate formation.
4. Numeric reservoir simulation studies for exploring the efficiency and practical limitations associated with various CO_2 injection scenarios and different reservoir characteristics.

A major element of the GSC study was the identification and screening, on a regional basis, of candidate geologic reservoirs having geologic and geothermal conditions suitable for the formation and long-term sequestration of CO_2 as gas hydrate, and which are located in reasonable proximity to existing CO_2 production sources. The long-term viability of this CO_2 storage option depends on two assumptions: 1) that CO_2 sequestered as solid-phase gas hydrate remains much less mobile than CO_2 sequestered in gaseous or liquid phases, and 2) adequate screening of candidate geologic reservoirs will ensure that sequestered CO_2 hydrate will be insulated (by the overlying sediments) from the effects of climate warming for sufficiently long time periods.

The possibility of CO_2 injection and subsequent formation of stable CO_2 hydrate within unconsolidated sediments or porous bedrock reservoirs affords considerable potential for effective long-term management of CO_2 emissions from industrial sources in Canada. The present study follows a previous assessment of the potential for sequestration of CO_2 as gas hydrate in sediments underlying Canada's Great Lakes, which identified a number of candidate basins having very large CO_2 sequestration potential in sediments beneath the deeper portions of Lake Superior (Wright et al., 2006). Although it was estimated that a capacity of up to 90 Gt or more of CO_2 could be sequestered in sediments of the Great Lakes Basin, prevailing technological and economic constraints limit the practical utilization of the bulk of this capacity in the near term. However, two candidate basins beneath the Canadian portion of Lake Superior were identified as being potential near-term targets given their location within 10 km of shore (within range of land-based drilling technologies) and their general proximity to industrial sources of CO_2. In this work we apply similar techniques for assessing regional geological, geothermal and geopressure regimes to evaluate the potential for CO_2 sequestration as gas hydrate in geologic reservoirs within the Alberta extent of the Western Canada Sedimentary Basin (WCSB).

2. FUNDAMENTAL PROPERTIES OF GAS HYDRATES

2.1 Molecular configuration of gas hydrates

Gas hydrates are ice-like solids consisting of a three-dimensional lattice of hydrogen-bonded water molecules configured to form numerous cavities, each of which may be occupied by a single “guest” molecule of certain species of gases. Common guest molecules include gaseous methane (CH_4), propane (C_3H_8), isobutane (C_4H_{10}), and CO_2. Guest molecules are positioned within the lattice by relatively weak van der Waal’s forces (Sloan, 1998). The precise configuration of the host lattice is dependent primarily on the size and shape of the guest molecule. Sufficient numbers of guests within the structure are required to maintain stability of the lattice. Ideally, each cavity within the host lattice would be occupied by a guest, but the actual degree of cavity filling is dependent on the temperature and pressure conditions during hydrate formation (Makogon, 1981).

Figure 2 illustrates the three basic cavity configurations common to natural gas hydrates, distinguished on the basis of the arrangement of molecules forming the host lattice. These cavities (or cages) may be visualized as quasi-spherical polyhedra, with the vertices of individual facets defining the position of water molecules, and facet edges representing hydrogen bonds between water molecules (Sloan, 1998). The pentagonal dodecahedron (designated as 5^{12}) is the smallest form and consists of 12 pentagonal faces forming a regular polyhedron, and will accommodate molecules with diameters smaller than about 4.6 Angstrom Units (Å). The most non-spherical of the three cage types, the tetrakaidecahedron ($5^{12}6^{2}$), has two hexagonal faces in addition to 12 pentagonal faces, and will host molecules smaller than 6.0 Å. The hexakaidecahedron ($5^{12}6^{4}$) is the largest of the three forms and will accommodate molecules as large as 6.6 Å. The hexakaidecahedron is nearly spherical, with four hexagonal and 12 pentagonal faces.

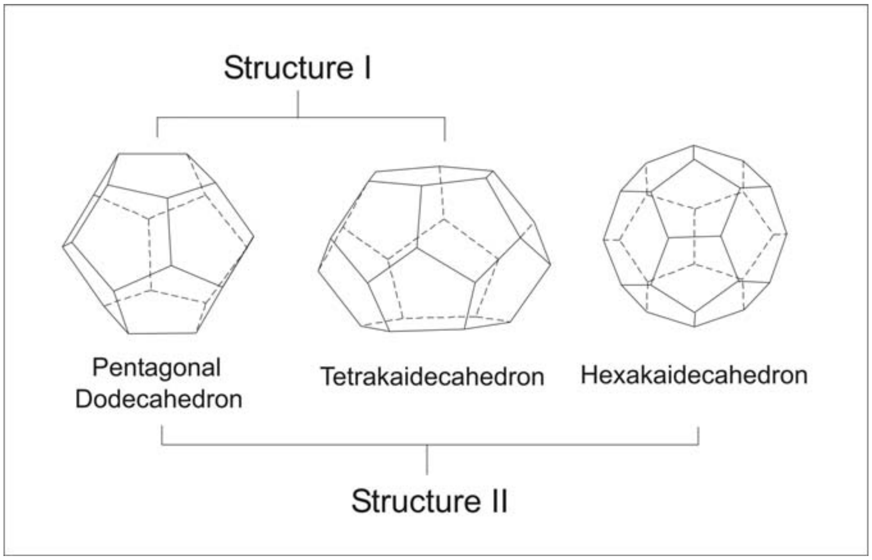

FIGURE 2. Cage configurations for structure I and structure II gas hydrates (after Sloan, 1998).

2.2 Unit cell structures for gas hydrates

Both carbon dioxide (CO_2) and methane (CH_4) are examples of gases that form structure I hydrates. Structure I (sI) and structure II (sII) are the most common unit cell structures recognized thus far. Each is composed of a unique packing arrangement of two of the three individual polyhedra shown in Figure 2. Structure I hydrates consist of two 5^{12} (small) cages and six $5^{12}6^{2}$ (large) cages. In a mass of hydrate, the unit structure serves as a template for the growth of the gas hydrate crystal in three dimensions, such that the unit structure is repeated many times. In both sI and sII hydrates, the extension of the host lattice through three dimensions is accomplished through face-sharing of adjacent polyhedra. After accounting for shared polyhedral edges and faces, the unit cell contains 46 water molecules, forming eight cavities, each of which may be occupied by a single guest molecule. The ratio of water molecules to guest molecules is known as the *hydration number*, and is the basis for determining the amount of gas entrained within the gas hydrate structure. Therefore, with all cages occupied, the ideal *hydration number* for sI hydrates is 5.75 (46:8). Hydration numbers greater than this value imply that not all of the cages within the host lattice are occupied by guest molecules.

Individual cages may be occupied by a single guest molecule of suitable size (Figure 3). In addition, guest molecules must occupy a sufficient proportion of cavities to stabilize the host lattice. Molecules that are too large to stabilize a 5^{12} cage may serve as guest molecules in larger $5^{12}6^{2}$ or $5^{12}6^{4}$ cages. In cases where a significant number of cages remain unoccupied, the ratio of the number of water molecules to guest molecules is greater (i.e. a larger value of the hydration number) and the hydrate will be a less efficient storage medium for gas.

Molecules with diameters greater than about 6.6 Å are too large to stabilize sI or sII lattices. Ripmeester and Ratcliffe (1990) have determined that some large molecules may serve as guests in a recently discovered structure H lattice, usually requiring a “help gas” to stabilize the small 5^{12} cages within the structure. Molecules with diameters less than about 3.0 Å are small enough to pass through the hydrogen bond framework of any known hydrogen bond lattice, and therefore, will not form hydrates (Sloan, 1998).

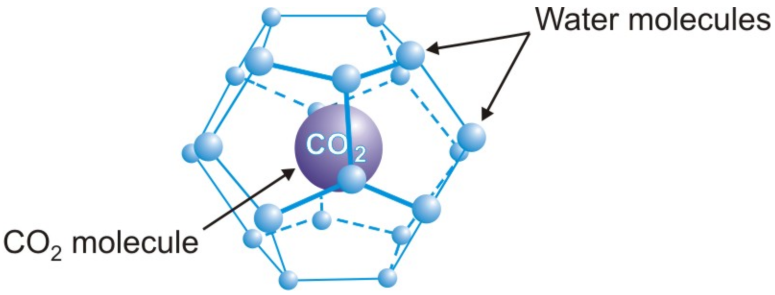

FIGURE 3. CO_2 molecule occupying a small 5^{12} cage.

The chemical formula for sI CO_2 hydrate is $CO_2 \bullet 5.75\ H_2O$ (or for a unit cell of CO_2 hydrate: $8\ CO_2 \bullet 46\ H_2O$). In theory, if all of the hydrate cages were occupied by CO_2, then 1 m^3 of CO_2 hydrate would contain approximately 164 m^3 of CO_2 gas at standard P-T conditions. However, a somewhat reduced volumetric efficiency generally occurs, with less than 100% of CO_2 hydrate cages being occupied by CO_2 guest molecules (Wadsley, 1995; Uchida et al., 1996; Kvenvolden, 1998; Ohmura and Mori, 1998). Experimental determination of the ratio of water molecules to CO_2 molecules reported in the literature ranges from 5.82 to 7.80 (Ohmura and Mori, 1998). As a result, 1 m^3 of CO_2 hydrate may contain between 120 - 162 m^3 of CO_2 at standard P-T conditions (Figure 4). Cage occupancy also varies with temperature and pressure (Clennell et al., 1999; Anderson et al., 2003).

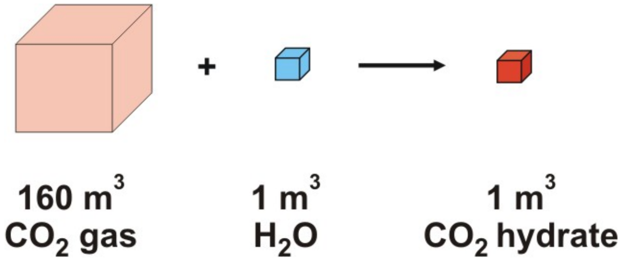

FIGURE 4. Volumetric composition of CO_2 hydrate. Typically between about 120-160 volumes of CO_2 gas (at STP equivalent) may be contained in a single unit volume of CO_2 hydrate.

Figure 5 presents a phase composition diagram for CO_2, which describes the P-T conditions required to achieve CO_2 hydrate stability in pure water. Note the sharp inflection in the CO_2 hydrate stability curve at about 10°C and 4.5 MPa, corresponding to the intersection of the hydrate stability curve and the partition between gaseous and liquid phases of CO_2. The lightly shaded area in Figure 5 indicates the P-T region for which stable gas hydrate can exist in the presence of gaseous CO_2 and liquid water. At higher pressures (darker shade) excess CO_2 condenses into the liquid phase, such that within this region CO_2 hydrate may exist in conjunction with both gaseous and liquid CO_2 (Sloan, 1998).

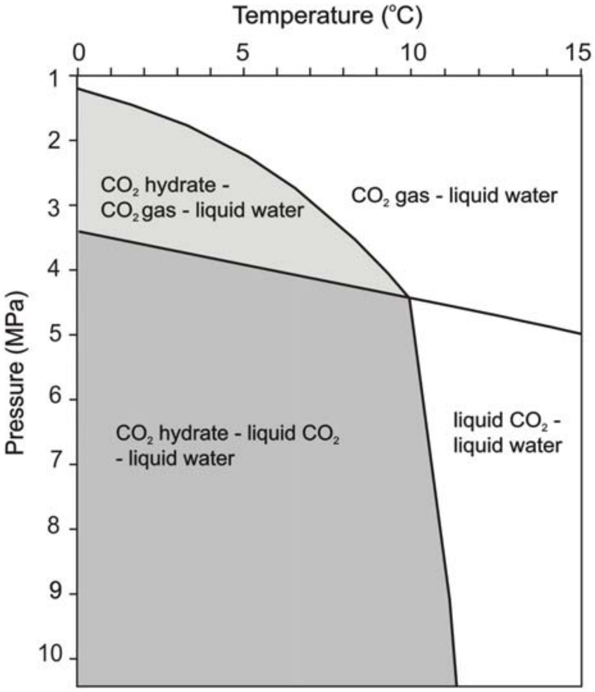

FIGURE 5. CO_2 Phase diagram showing P-T conditions for CO_2 hydrate stability. The sub-horizontal line intersecting the CO_2 stability curve defines the threshold between the gaseous and liquid phases of CO_2 (after Sloan, 1998).

Pore water salinity is a key factor controlling gas hydrate occurrence and stability in natural environments (Wright et al., 1999; 2005), with higher salinity values causing progressively greater shifts in the P-T threshold for gas hydrate stability (Figure 6). Hesse et al. (2000) concluded that pore water salts are excluded from the crystalline water matrix during the formation of gas hydrate, as is known to be the case during simple freezing of saline pore waters. At the Mallik gas hydrate research site in Canada's Mackenzie delta, several instances of sands having pore water salinities in excess of seawater values were observed at multiple locations within the gas hydrate reservoir. Although texturally similar to the neighbouring hydrate-bearing sands, these sands contained no gas hydrate. It is reasonable to speculate that the exclusion of pore water salts during gas hydrate formation within one portion of the reservoir has resulted in the concentration of these salts in the pore waters of adjacent sediments. Where the concentration of salts has been increased sufficiently, the formation of gas hydrate is inhibited locally.

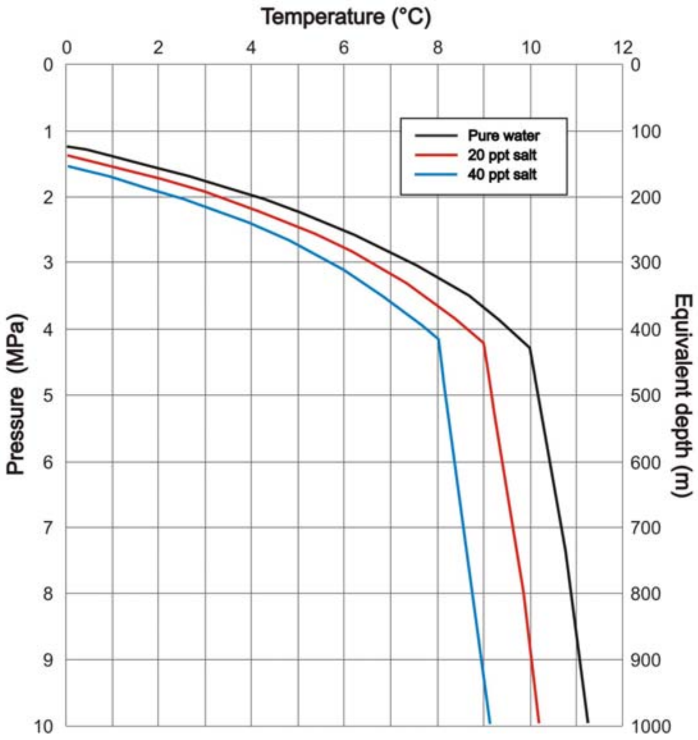

FIGURE 6. Equilibrium dissociation curve for CO_2 hydrate with pore water salinities of 0 ppt, 20 ppt, and 40 ppt (Sloan, 1998).

Results from a series of laboratory experiments conducted on sediments recovered from the Mallik 2L-38 well indicate that P-T stability conditions for methane hydrate grown in sands having a pore water salt concentration of 4 ppt did not differ greatly from those expected for pure methane-water systems (Wright et al., 1999). However, at higher salt concentrations of 20 ppt and 40 ppt, a distinct and progressive shift in the P-T threshold for gas hydrate stability was observed (i.e. towards higher pressures and lower temperatures). Subsequent experiments indicate that pore water salt concentrations ultimately limit the amount of gas hydrate that can be formed within the available pore volume of reservoir sediments (Wright et al., 2005). Therefore, apart from the physical and geothermal characteristics of potential candidate reservoirs, pore water salinity must be evaluated as part of any assessment of regional opportunities for the geological sequestration of CO_2 as gas hydrate.

3. CRITERIA FOR SCREENING OF CANDIDATE RESERVOIRS

Specific criteria for assessing the suitability of individual sedimentary formations for long-term geological sequestration of CO_2 are still under development, although in a general sense the major elements that should be considered in the screening process have been reasonably well defined. Geological suitability, while of primary importance, is only one of a number of factors that must be evaluated in the screening of candidate reservoirs for CO_2 sequestration in general. The number of reservoirs deemed suitable for CO_2 sequestration is significantly reduced when other important factors such as accessibility, extent and capacity of CO_2 transportation infrastructure, and injection and monitoring costs are taken into account. Finally, socio-political considerations may ultimately impose overriding constraints on the range of sequestration options that can be practically implemented, regardless of technical or economic feasibility.

To date, the most attention has been given to sequestration options in which injected CO_2 persists within the geological formation over the long-term in gaseous form or as a supercritical fluid (e.g. Bachu, 2003; Natural Resources Canada, 2006; Pooladi-Darvish and Mireault, 2008). The issue is fundamentally the same in the case of CO_2 sequestration as solid-phase gas hydrate, except that there is an additional requirement that pressure and temperature conditions within the reservoir must be conducive to the formation of CO_2 hydrate. Furthermore, the future response of the ground temperature regime to ongoing climate change is also an important factor in assessing reservoir suitability in order to ensure the long-term stability of the CO_2 hydrate sequestered within the reservoir.

In general, the geological suitability of potential candidate reservoirs for CO_2 sequestration as hydrate must consider the physical and geochemical attributes of the target bedrock formation and/or overlying surficial sediments, in terms of:

- *Pressure and temperature conditions* – P-T conditions within the target reservoir are conducive to the formation and maintenance of CO_2 hydrate.
- *Porosity* – the host sediment has adequate pore volume for storage of substantive amounts of CO_2 as gas, supercritical fluid, or gas hydrate.
- *Permeability* – pore size distribution and connectivity are adequate to ensure reasonable CO_2 injectivity and efficient reservoir filling.
- *Thickness and extent* – the reservoir is sufficiently large to provide economical storage capacity within the constraints of available technology.
- *Geochemistry* – the injection of CO_2 is unlikely to induce chemical reactions which degrade the structural integrity of the host reservoir.
- *Hydrodynamic regime* – formation waters are sufficiently isolated from fresh water aquifers comprising the domestic water supply.
- *Proximity* – candidate reservoirs are close to CO_2 generation sources and/or suitable CO_2 transport infrastructure (e.g. pipelines).
- *Accessibility* – the reservoir can be accessed readily and economically using existing drilling and injection technologies.

The screening process should also consider the local/regional tectonic setting, specifically with respect to the frequency and magnitude of large earthquakes having the potential to adversely affect the physical integrity of the host formation. In addition, a detailed assessment of individual candidate reservoirs should consider the distribution and extent of geological faults so as to minimize the potential for reservoir leakage through cross-cutting fractures connecting adjacent sedimentary horizons. This aspect of reservoir screening will not be addressed in this report.

Although the WCSB extends into both Saskatchewan and Manitoba, this report focuses on the Alberta portion which benefits from a relative concentration of stationary CO_2 sources, versus the comparatively dispersed distribution of CO_2 sources in Saskatchewan and Manitoba which are mostly related to agriculture production and transportation. Although on a per capita basis

Saskatchewan is a heavy CO_2 emitter, the total amount of emissions is very low when compared to Alberta. If air capture technologies (e.g. Keith et al., 2006) produce a viable option for capture of CO_2 from non-stationary sources such as the agriculture sector, the extensive pipeline network (Section 12) could allow for transportation of CO_2 to Alberta for storage, or options for local sequestration as gas hydrate could be investigated.

The following sections will focus on the identification of regions within the Alberta portion of the WCSB for which geologic and geothermal conditions are suitable for sequestration of CO_2 as gas hydrate. An overview of the geological setting, followed by a discussion of the major geological and geographical factors which constrain the selection of reservoirs suitable for the formation and sequestration of CO_2 as gas hydrate will be presented. An assessment of the geological suitability of candidate reservoirs within the sub-regions of Alberta, based on broad regional patterns of geology and geothermal setting, will identify areas with significant potential for CO_2 sequestration as gas hydrate.

4. CO_2 SOURCES IN ALBERTA

Alberta is a major energy producer. One aspect of energy production in Alberta encompasses the extraction and processing of petroleum-based products derived from conventional oil and natural gas reserves, and more recently the intensive development of heavy oil bitumen from extensive oil sand deposits in northern Alberta. Power generation to sustain increasing domestic and industrial demand is based almost entirely on the burning of fossil fuels, primarily coal. Therefore, it is not surprising that in 2010 Alberta had the highest CO_2 emissions in Canada, estimated at ~233 Mt/yr, compared with ~72 Mt/yr for Saskatchewan, ~20 Mt/yr for Manitoba, and ~361 Mt/yr for the rest of Canada (Alberta Environment and Sustainable Resource Development, 2012a). An inventory of emission sources in Alberta shows that nearly 47% of CO_2 is generated from large, stationary sources, such as power plants, refineries, oil sands production, and petrochemical and cement plants (Figure 7). This is in contrast with the CO_2 emissions profile in other major CO_2 producing provinces (Ontario and Québec), where a larger proportion of anthropogenic CO_2 is produced by transportation, consisting of small, mobile and distributed sources. Alberta's largest CO_2 emissions are generated by coal-fired power plants and oil sands plants, with a large cluster of emissions sources in the vicinity of Edmonton and a smaller cluster north of Fort McMurray (Figure 8). The Sundance coal-powered thermal electric power generating plant, 70 km west of Edmonton, is the largest emitter in the province with ~16 Mt of CO_2 released per year.

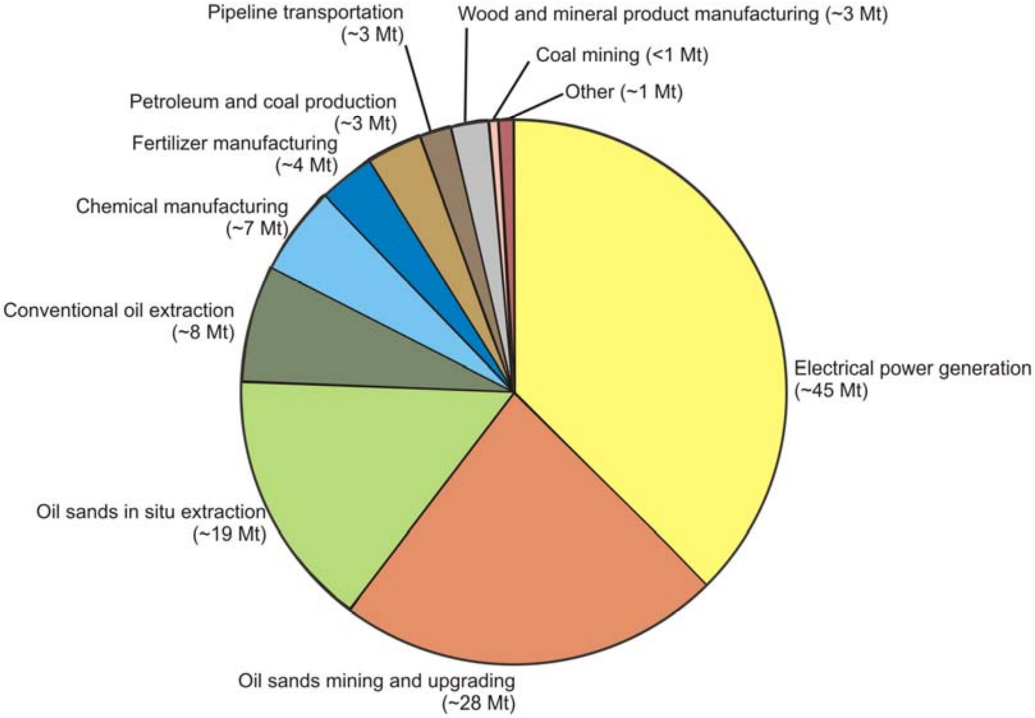

FIGURE 7. Pie chart showing the contribution by sector of the estimated 122.5 Mt of CO_2 equivalent emissions from stationary sources in Alberta in 2010 (Alberta Environment and Sustainable Resource Development, 2012a). Note, 96% (117.6 Mt) of greenhouse gas emissions in Alberta are CO_2.

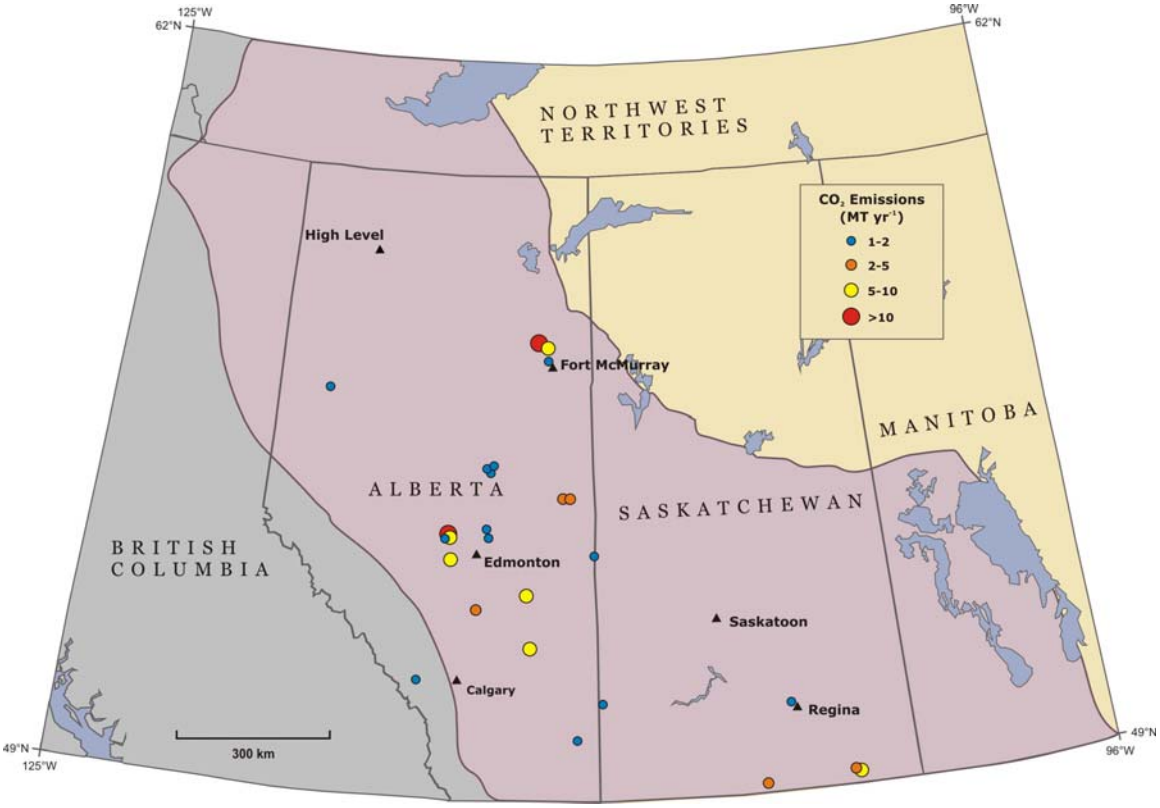

*FIGURE 8. Stationary emission sources within the WCSB with CO_2 emissions greater than 1 MT per year. Emissions data are from 2010 (*Alberta Environment and Sustainable Resource Development, 2012b*).*

5. OVERVIEW OF REGIONAL GEOLOGY

Alberta is underlain almost entirely by the extensive WCSB. This mature sedimentary basin is rich in conventional oil and gas reservoirs, heavy oil and bitumen (tar) sands, coal and salt beds, and deep saline aquifers (Figure 9). Most oil or gas deposits were not formed within the reservoir in which they are currently found (i.e. a closed-system reservoir). Rather, the oil or gas is typically formed in deeper source rocks rich in organic matter, commonly black waxy shales. By contrast, in an open-system petroleum reservoir the oil/gas migrates through permeable rock, often over large distances, finally accumulating beneath a structural seal or trap that prevents or limits further migration.

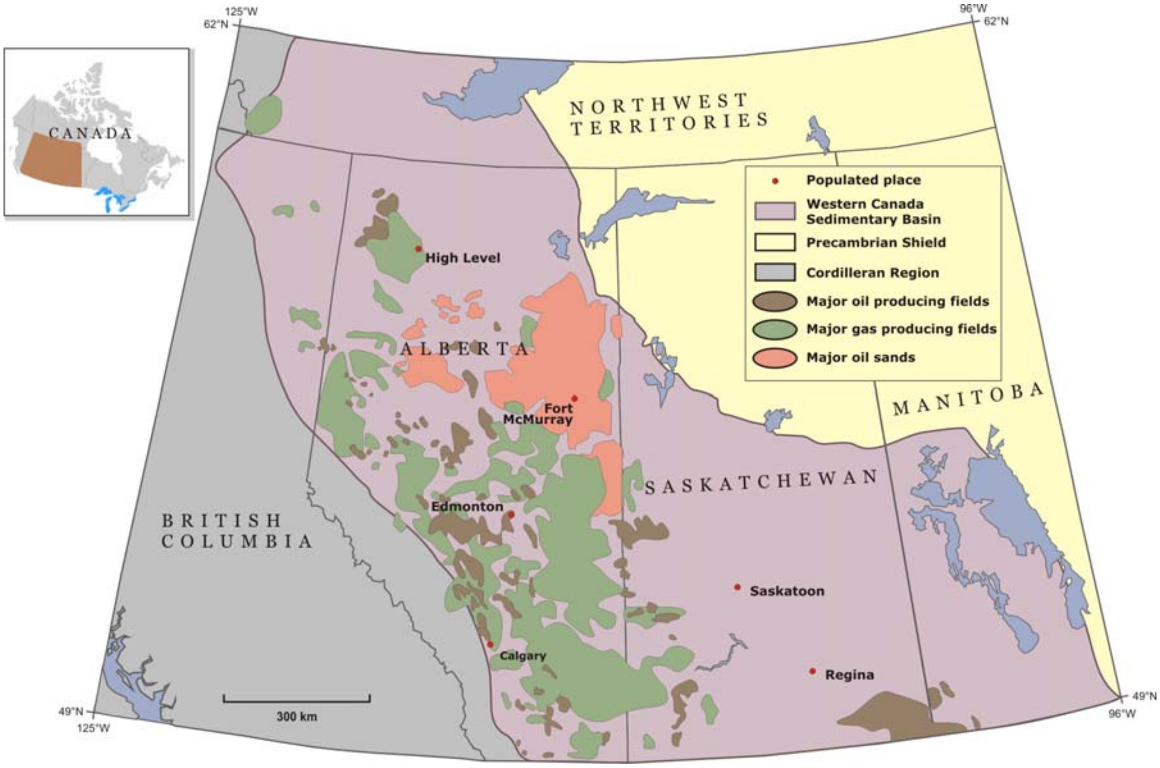

FIGURE 9. Map of western Canada showing location of the WCSB with major oil and gas producing fields, and major oil sands deposits (Natural Resources Canada, 2010).

In the case of a CO_2 sequestration operation, the CO_2 gas is produced from anthropogenic sources and the connecting pipeline network serves as the migratory pathway. The geological characteristics that result in the WCSB being the major hydrocarbon producing area in Canada also make it one of the areas with the greatest potential for CO_2 sequestration. The two primary suitability criteria are: 1) the occurrence of a porous reservoir rock to host oil and gas accumulations (i.e. CO_2) - typically sandstones, limestones, and dolomites, and 2) the presence of an overlying impermeable cap-rock to contain the oil and gas (CO_2) and prevent it from migrating upwards and eventually seeping to the surface. The WCSB has been identified as a world class site for geological storage of CO_2 in the gas and/or liquid phase (Bachu, 2003; Natural Resources Canada, 2006). In contrast, the other major CO_2 emitting provinces, Ontario and Québec, are underlain mostly by rocks of the Canadian Precambrian Shield, which are generally unsuitable for CO_2 injection and storage because of their fractured nature, low porosity, and low permeability.

5.1 Stratigraphy and regional tectonics

The WCSB is a massive wedge of consolidated sedimentary rocks extending eastward from the foothills of the Cordilleran Region, across the Interior Plains of Alberta, Saskatchewan, and Manitoba where its eastern limit abuts against the igneous and metamorphic rocks of the Precambrian Shield (Figure 10). The Basin has an areal extend of ~1.4 million km^2, and a maximum thickness of 6 km along its western margin. The stratigraphic history of the area is dominated by a sequence of marine inundation, sediment deposition and erosion, and consolidation. The Precambrian crystalline basement rock, formed over 1 billion years ago, was eroded to a nearly-flat surface and was then depressed below sea-level creating an extensive basin.

The consolidated sedimentary rocks which overlay the basement rock range in geological age from Cambrian to late-Tertiary. The strata can be classified into two broad divisions that reflect contrasting geological conditions. The lower succession, formed before the major uplift of the Canadian Cordillera, is composed largely of carbonate rocks of Cambrian to Jurassic age (about 570-180 million years before present) deposited in a warm continental sea environment, with a component of evaporite minerals (anhydrite, halite, and potash). The Devonian reef complexes and Mississippian carbonates contain much of western Canada’s oil and gas reserves. The upper succession of sedimentary strata was formed as major mountain-building and uplift in the Cordillera occurred as the North American continent moved westward and collided with the Pacific crustal plates during the mid-Jurassic to Tertiary period (about 170 million years BP). Clastic sediments (sandstone and shales) were subsequently eroded from the newly formed mountains and deposited eastward into the continental sea. These clastic rocks are relatively porous and permeable and commonly are host to deposits of oil and gas. Figure 10 presents a west-east trending geological section across the WCSB. Geological units rich in oil and gas deposits have been identified in Devonian, Carboniferous, Triassic, and Cretaceous formations, with minor petroleum deposits being identified in Permian and Jurassic units.

Much of the upper surface of the sedimentary wedge is covered by unconsolidated glacial drift laid down by at least five successive periods of glaciation during the Pleistocene Epoch (2 million to 11,000 years BP). The geological history of this area is discussed in detail in *The Atlas of the Western Canada Sedimentary Basin* (Messop and Shetsen, 1994).

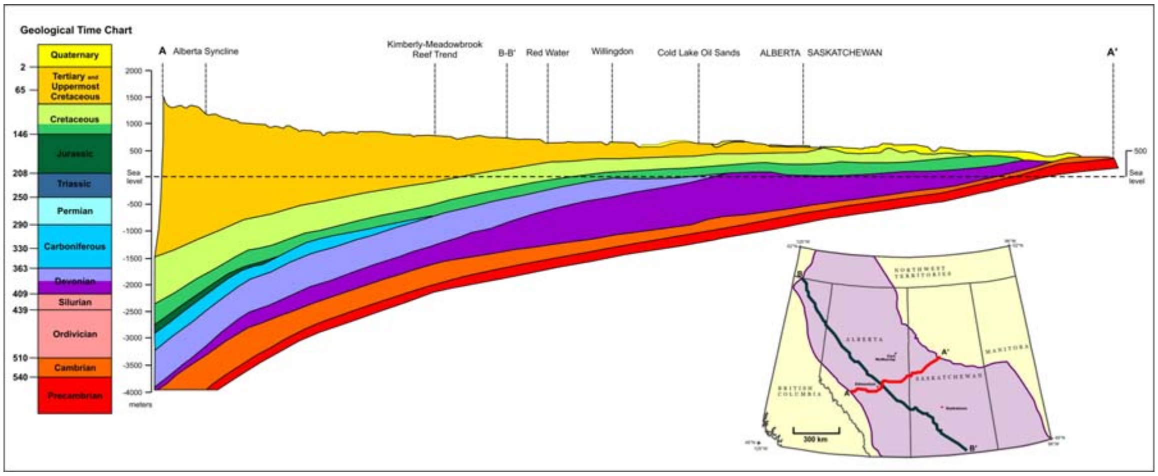

FIGURE 10. Simplified geological section across the WCSB from the eastern edge of the Rocky Mountains to north-central Saskatchewan (modified from Wright, 1984; Wright et al., 1994).

5.2 Evaporites

During the Lower and Middle Devonian Periods the WCSB was the site of extensive deposition of evaporites. The majority of these salts are concentrated in the Elk Point Group strata, which extends from the upper Mackenzie River basin through northern and central Alberta into Saskatchewan (Figure 11). Within Alberta, this salt is concentrated in three formations of the Elk Point Group: 1) the Lotsberg (Lower and Upper Lotsberg Salt), the Cold Lake (Cold Lake Salt), and the Prairie Evaporite (Whitkow and Leofnard Salt) (Figure 11). The regional distribution and thickness of the major components of Elk Point Group have been investigated by Grayston et al. (1964), Hamilton (1971), and Meijer Drees (1986, 1994). Most recently, Grobe (2000) established a database of stratigraphic picks from which the extent and thickness of the various salt formations were mapped.

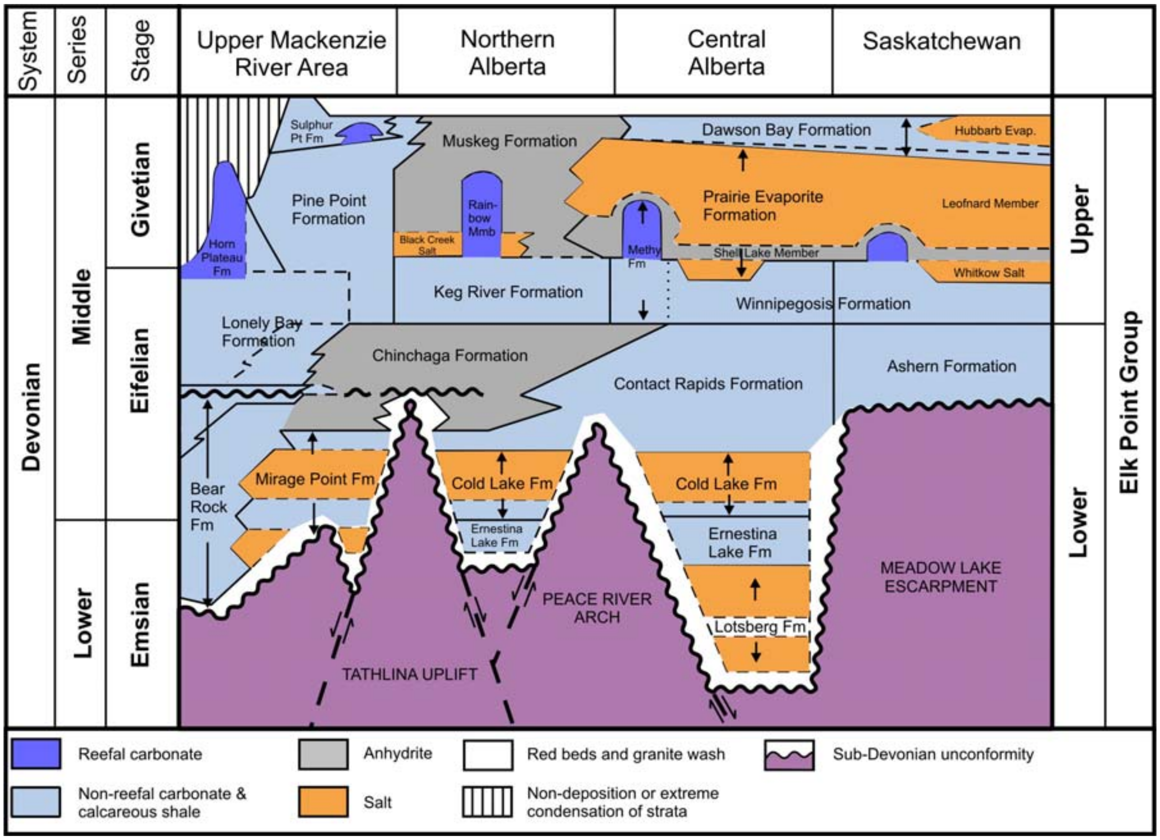

FIGURE 11. Simplified table of formation of the Devonian Elk Point Group highlighting the occurrence of salt formations (modified from Meijer Drees, 1986).

The Lotsberg salts were deposited during the Lower Devonian Period in a tectonically stable, continental environment (Meijer Drees, 1986; Wardlaw and Watson, 1966). At the beginning of the Middle Devonian, the sea inundated these continental basins. It is hypothesized that, over time, the channels filled with sediment, resulting in a restricted circulation in the Northern and Central Alberta sub-basins. Evaporation of the sea water then led to the deposition of salt. The Lotsberg Formation is composed of two salt beds, the Lower Lotsberg Salt and the Upper Lotsberg Salt, separated by an interval of red shale (Hamilton, 1971).

The Lotsberg salt formation is the least extensive of the three salt deposits and has a maximum thickness of 150 m near Cold Lake. The deposit lies beneath an overburden which ranges from approximately 800 m in thickness at the Alberta-Saskatchewan border to over 2000 m near Edmonton. The Cold Lake Formation is comprised of two salt deposits separated by a paleotopographic high which is part of the Peace River Arch (Meijer Drees, 1986). These salt deposits are relatively thin, with maximum thicknesses of ~70 m near Wood Buffalo National Park. The overburden thickness above the Cold Lake salt formation ranges from 600 m to 2300 m. The most extensive salt deposit in Alberta is the Prairie Evaporite formation (Figure 11). This salt bed is more than 300 m thick in the area north of Fort McMurray, thinning to less than 25 m in south-central Alberta. Overburden thickness ranges from about 2000 m in south-central Alberta near Red Deer, thinning to about 300-400 m near Fort McMurray. The significance of these salt formations with respect to regional potentials for geological sequestration of CO_2 as gas hydrate is discussed in Section 8.

5.3 Seismic Hazards

Ideally, CO_2 sequestration operations should be conducted in areas having a low risk of high-magnitude earthquakes that may damage the structural integrity of target reservoirs. The WCSB is an area of very low tectonic activity as there are no known active faults in the area (Martens and Atkinson, 2008). Approximately 99 low magnitude (3.0 to 3.9) earthquakes have occurred within the WCSB during the period from 1970-2009 (Earthquakes Canada, 2009). Only one earthquakes of moderate magnitude (5+) or greater have occurred within the Basin since 1970. The adjacent Cordilleran Region of British Columbia and Northwest Territories are also tectonically stable.

Martens and Atkinson (2008) conducted a probabilistic analysis of seismic hazard in Alberta using the Seismic Hazard Earthquake Epicentre File (SHEEF) maintained by the GSC. Using earthquake occurrence records from pre-1900 to 2006, they constructed a map outlining relative seismic hazard zones in Alberta (Figure 12).

Debate within the seismology community persists as to whether oil and gas-related injection and production can cause earthquakes. Oil and gas exploration and development has been prolific in Alberta, yet only a few areas along the Rocky Mountain foothills have experienced seismic events which have been attributed to this activity (Wetmiller, 1986; Horner et al., 1994). This suggests that pre-existing geological conditions and stress regimes are a requisite for the induction of earthquakes due to human-activities.

However, the network of earthquake monitoring stations in Alberta is very sparse and low magnitude events are potentially missed by the instrumentation. It has been hypothesized that the injection of gas or liquid CO_2 can cause small earthquakes which in turn may result in fracturing of formerly stable reservoirs and the potential for CO_2 leakage (Sminchak and Gupta, 2003). Although a number of studies have addressed this question in recent years, as yet there has been no definitive conclusion regarding possible causal relationships between CO_2 injection for sequestration purposes and the occurrence of localized earthquakes.

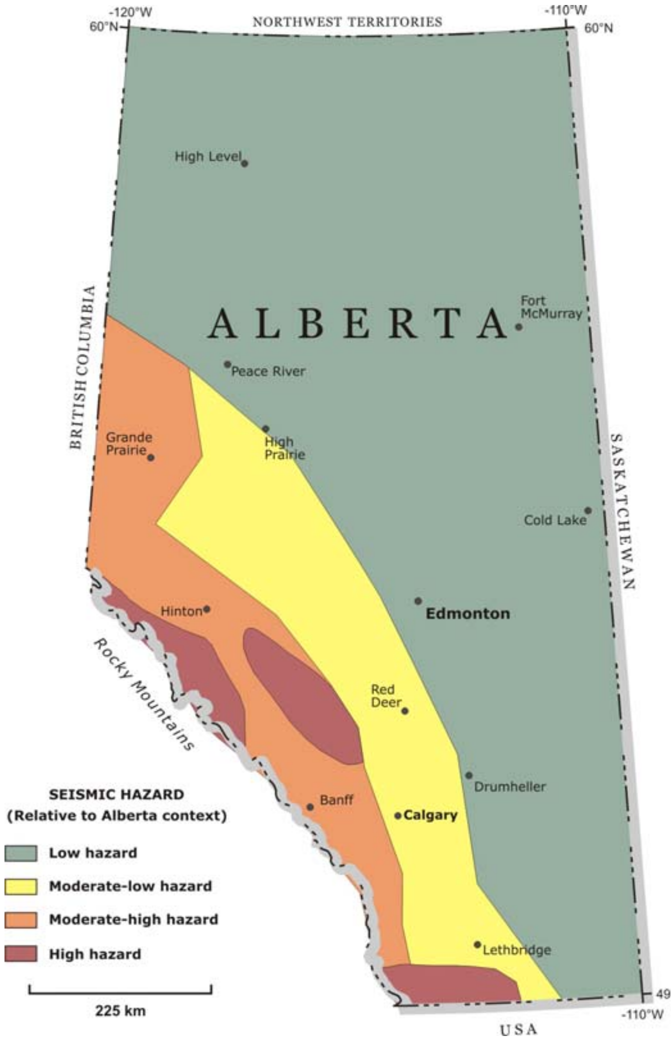

FIGURE 12. Seismic hazard map for Alberta (Martens and Atkinson, 2008). Note that hazard zones designations are relative to an Alberta context, and that zones classified as "high" in fact have a much lower seismic hazard than more active areas in Canada such as the west Coast or the Ottawa-St Lawrence River valleys.

6. ANALYSIS OF REGIONAL POTENTIALS FOR CO_2 SEQUESTRATION AS GAS HYDRATE

A Geographic Information System (GIS) was employed to analyze the potential to sequester CO_2 as gas hydrate in Alberta, utilizing available information about ground surface temperatures and geothermal gradients (Figures 13a, 13b), together with estimates of pore pressures at depth.

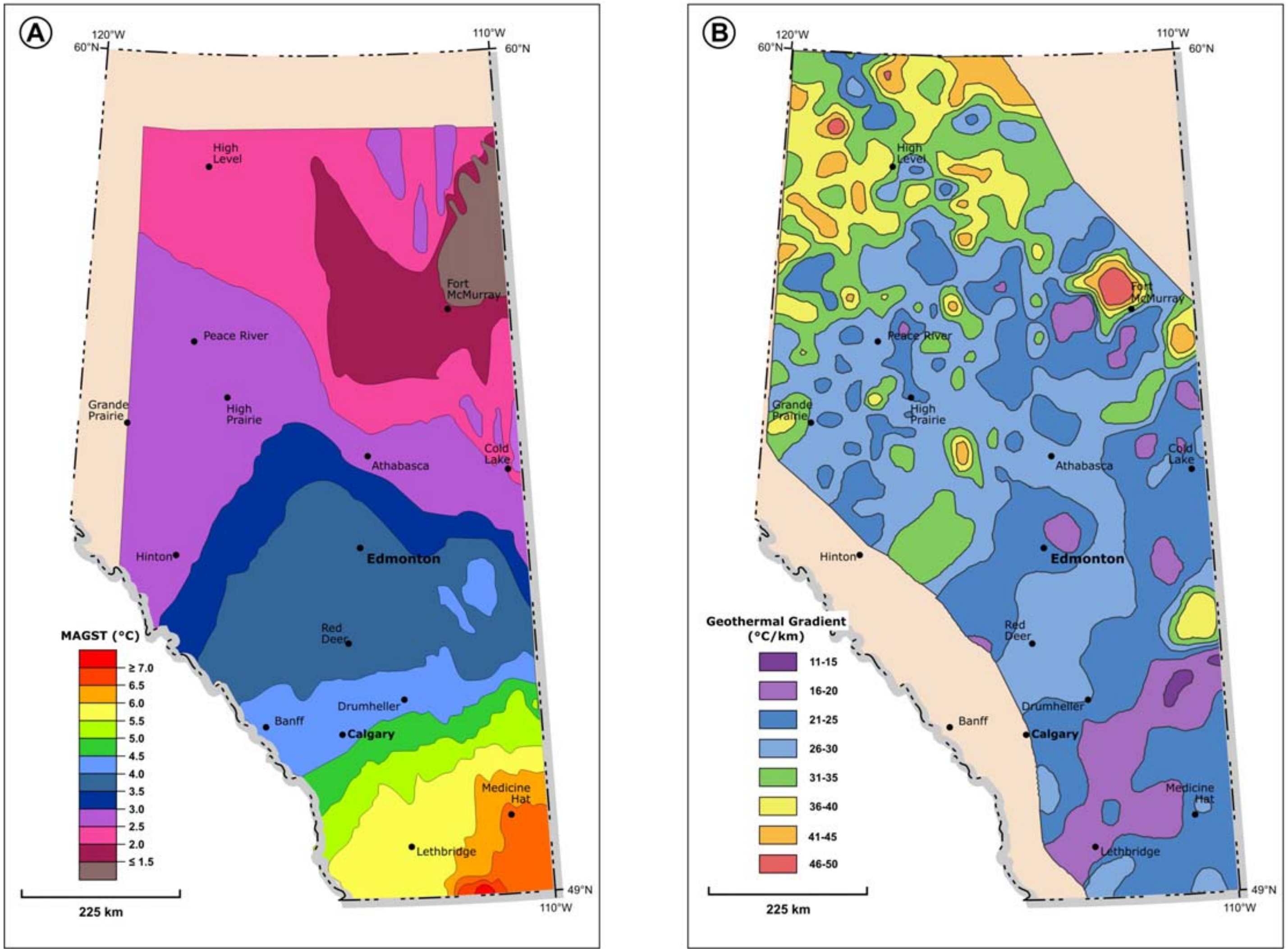

FIGURE 13. A) Mean annual ground surface temperature (Majorowicz, 2006). B) Geothermal gradient (after Bachu and Burwash, 1994).

6.1 Estimating Ground Temperatures at Depth

Regional ground surface temperatures were interpolated from a temperature contour map produced by Majorowicz (1996; 2006), based on approximately 65 surface temperature logs. In general, ground temperatures at shallow depths show a conspicuous deviation from the deeper, near-linear ground temperature profiles, with this deviation typically occurring at depths of between 70-80 m (Figure 14). This indicates that ground temperatures at depth are not in equilibrium with the current ground surface temperature regime, and probably reflect paleo-conditions associated with a major ice age (Majorowicz, 1993; 2006). Majorowicz (1993) suggests that present-day surface temperatures are between about 1.5°C and 2.5°C warmer than those implied by linear extrapolation of the deeper ground temperature profiles to the ground surface. Therefore, in order to estimate current ground temperatures at depth, we have applied a conservative adjustment factor of -1.5°C to the ground surface temperature information shown in Figure 13a, with subsequent extrapolation along the assumed geothermal gradient to the depth interval of interest (i.e. 200-500 m) as illustrated in Figure 14.

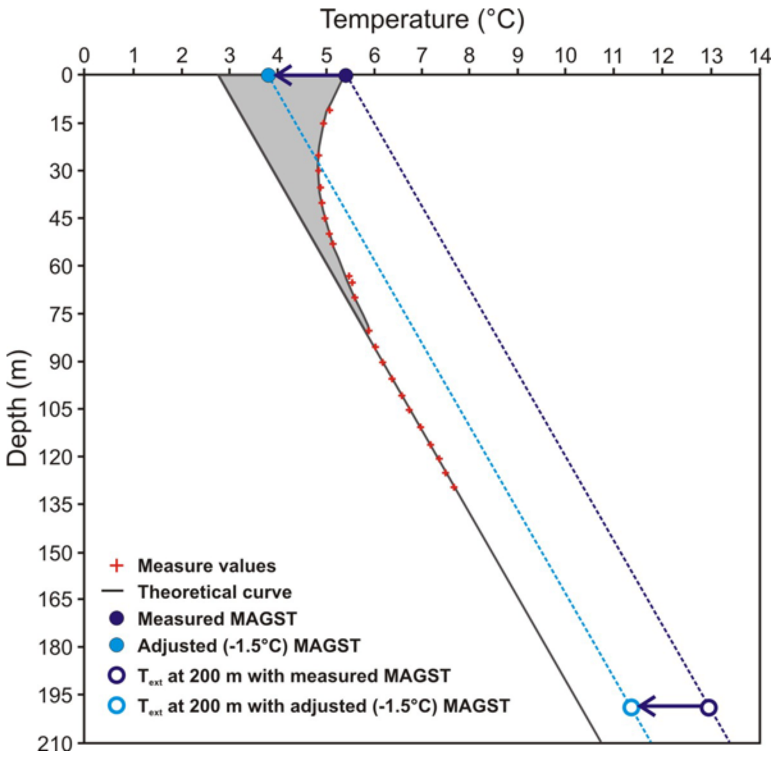

FIGURE 14. Temperature-depth profile at Sion, Alberta showing typical deviation at ~80 m from the linear profile at depth, with the warming of the top ~80 m shown by shading. The application of a conservative adjustment factor of -1.5°C to the Mean Annual Ground Surface Temperature (MAGST) and subsequent extrapolation of this temperature along the assumed geothermal gradient is illustrated with filled and open circles (modified from Majorowicz, 1993).

Bachu and Burwash (1991, 1994) produced a contour map of regional geothermal gradients within the WCSB, based on point measurements of bottom hole temperature (BHT) and estimated ground surface temperatures. BHTs were obtained for 1473 industry wells which reached the Precambrian basement. The wells were well-distributed spatially, and multiple BHT measurements were recorded for each well. Surface temperatures were estimated from air temperature measurements at 558 climatic stations (Environment Canada, 1982a,b). The integral geothermal gradient (G) was calculated at each point location as the ratio of the temperature difference between the bottom (T_B) and the top (T_S) of the profile, to the total depth (D).

$$G = (T_B - T_S)/D$$

These point data were subsequently interpolated to generate the final contour interval map of regional geothermal gradient (Bachu and Burwash, 1991; 1994).

To facilitate our regional analysis of CO_2 hydrate stability, we have interpolated these contours using a commercial GIS to derive a laterally continuous map of geothermal gradients (Figure 13b). Ground temperatures at T_B equal to 200 m, 300 m, and 400 m were estimated using the following equation:

$$T_B = T_S + (G \times D)$$

6.2 Estimating Pore-Pressures

Given that gas hydrate stability in nature is primarily a function of temperature and pressure (discounting the influence of salinity for now), it is important to evaluate the geopressure regime in conjunction with the ground temperature regime described above. For the sake of simplicity, we have assumed a near-hydrostatic geopressure regime, in which pore pressures increase with depth at a rate of 1 MPa per 100 m of burial (as shown in Figure 6). For the present study, this is sufficiently close to the accepted hydrostatic pressure gradient for fresh water of 9.792 kPa m^{-1}. Therefore, local gas hydrate stability may be evaluated on the basis of estimates of ground temperature at depth (derived from surface temperature and geothermal gradients), and from estimates of pore pressure based on depth below ground surface. An example of the criterion for a qualitative assessment of the potential (good, marginal, unlikely) for CO_2 sequestration as gas hydrate at 200 m, 300 m, and 400 m depth with reference to a hypothetical ground temperature profile is shown in Figure 15. Using a commercial GIS, these criteria were applied to the estimated ground temperature profile representative of each 1 km^2 grid cell within the study area, such that maps of sequestration potential were generated for each of the depth intervals specified (Figure 16).

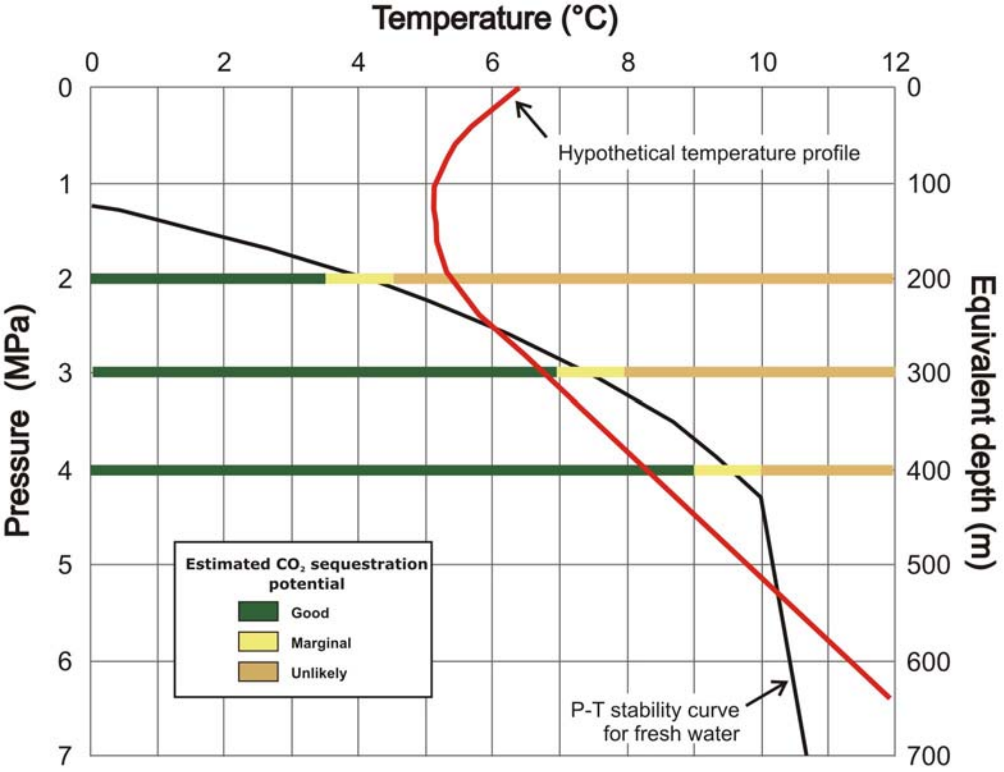

FIGURE 15. Criteria for designation of the CO_2 sequestration potential at three specified depths within a hypothetical geologic reservoir, based on estimated ground temperatures in relation to the CO_2 hydrate stability curve.

GIS-based regional-scale modeling of *in situ* P-T conditions suggests that at depths of less than 200 m, P-T conditions are generally unsuitable for the formation of stable CO_2 hydrate (Figure 16a). However, at depths of 300-400 m, our modeling predicts that substantial regional CO_2 sequestration potential may exist, mainly within the northeastern portions of the province (Figures 16b,c). For example, the P-T stability curve for 0 ppt salt indicates that at 300 m (P = ~3.0 MPa) stable CO_2 hydrate can form where ground temperatures are less than about 7.5°C (Figure 6). Modeling indicates that approximately 33,000 km^2 of the WCSB in Alberta may have P-T conditions at a depth of 300 m that are favourable to the formation of stable CO_2 hydrate (Figure 16b). The area between Cold Lake and Fort McMurray, and the area around High Level appear to be the most promising candidates for CO_2 sequestration as gas hydrate.

Following this broad-scale regional analysis, we have conducted a more detailed investigation based on localized data to assess the potential for geological sequestration of CO_2 as gas hydrate in portions of the Alberta WCSB. The following sections present data from point source locations, first from numerous boreholes drilled by industry and for which BHT measurements were recorded, and second from a limited number of abandoned industry boreholes that were subsequently instrumented for scientific research purposes.

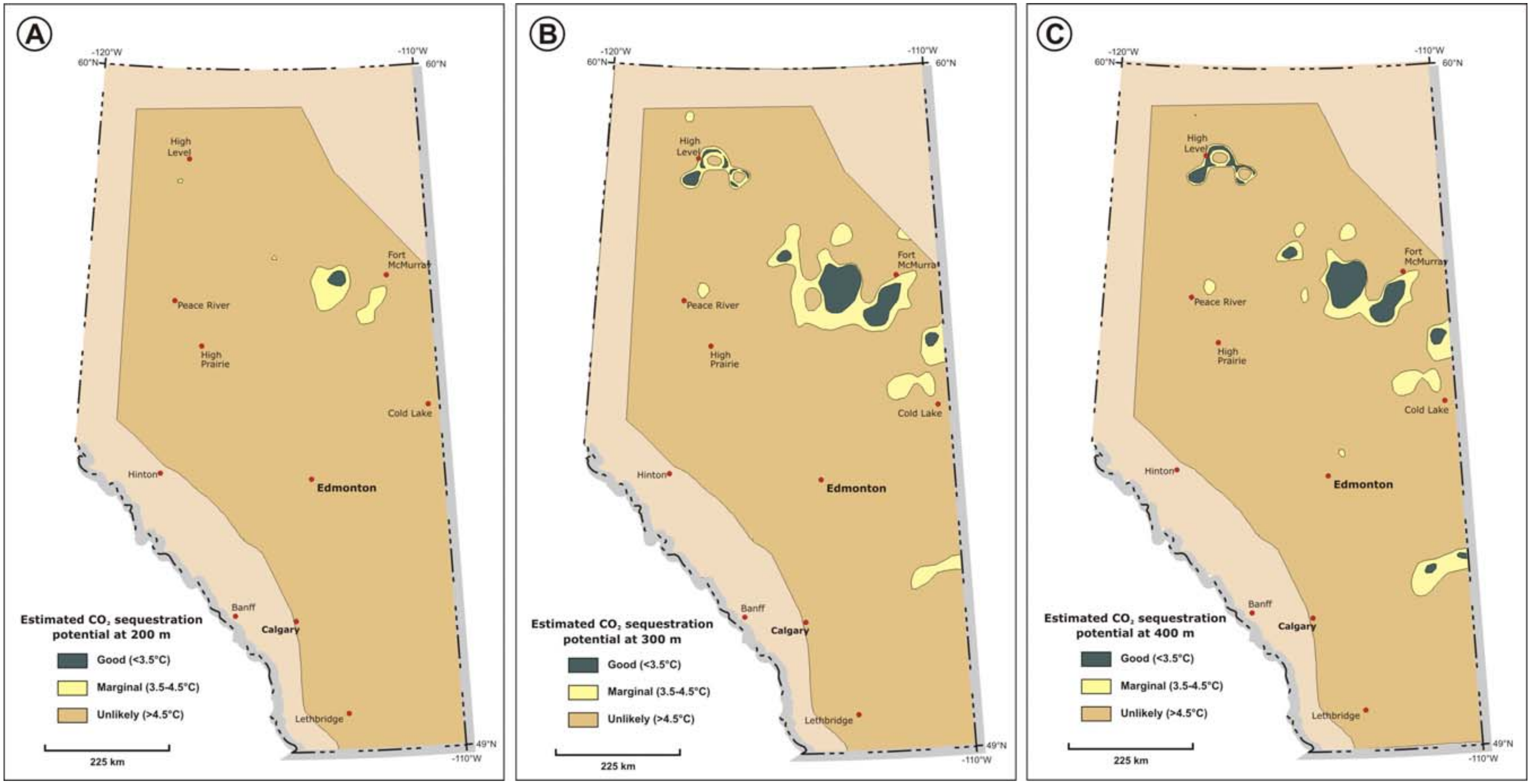

FIGURE 16. Regional-scale modeling of ground temperature at A) 200 m, B) 300 m and C) 400 m using estimates of regional geothermal gradients and mean annual ground surface temperatures. Assuming a normal hydrostatic pressure gradient, the rated sequestration potential is classified as "Good" where ground temperature is well within the CO_2 hydrate stability field, "Marginal" where ground temperature is within 0.5°C of the stability threshold, and "Unlikely" where ground temperature is more than 0.5°C outside the CO_2 hydrate stability field.

7. P-T STABILITY ANALYSIS USING INDUSTRY BOREHOLE DATA

The Alberta Energy and Utilities Board (AEUB), now the Energy Resources Conservation Board (ERCB), publishes an annual statistical report summarizing petroleum reserves, supply and demand forecasts, and information on energy prices and economic performance. The ERCB periodically publishes a CD-ROM report containing detailed information about established petroleum reserves on a field and pool basis, which summarizes all crude bitumen, crude oil, and natural gas reservoirs in the province. As of 2008, 62,662 industry boreholes had been documented in Alberta, with 77% of these being drilled since 1980 (ERCB, 2008). The database was filtered for our purposes by discarding:

- all boreholes with no spatial information (972 points)
- all boreholes with no depth/temperature information (9,161 points)
- all boreholes with depths greater than 1500 m (15,188 points)
- all boreholes with depths less than 200 m (367 points)
- all boreholes with anomalous temperatures (10 points)

This resulted in a dataset of 36,764 industry boreholes for which suitable information about bottom-hole pressure and temperature conditions is available (Figure 17). The data are spatially very dense through southern and central Alberta, with fewer boreholes located in northern areas. Wood Buffalo National Park is a protected area, and hence no drilling is permitted within the park. Borehole densities in the areas around Fort McMurray and High Level, for which our modeling has predicted significant potential to sequester $CO_{2,}$ are much lower than densities in areas further south. It is unclear why these northern areas have not been intensively drilled to date.

An initial screening of Alberta gas pools was conducted by APA Petroleum Engineering Inc. under contract to the GSC (Shaw, 2005), using the AEUB borehole database (Alberta Energy and Utilities Board, 2001). This initial work has been revised and expanded in the following sections using the updated Energy Resources Conservation Board Gas Reserves database (ERCB, 2008), and subsequently integrated with regional modeling results to enable a more comprehensive assessment of Alberta's potential for geological sequestration of CO_2 as gas hydrate.

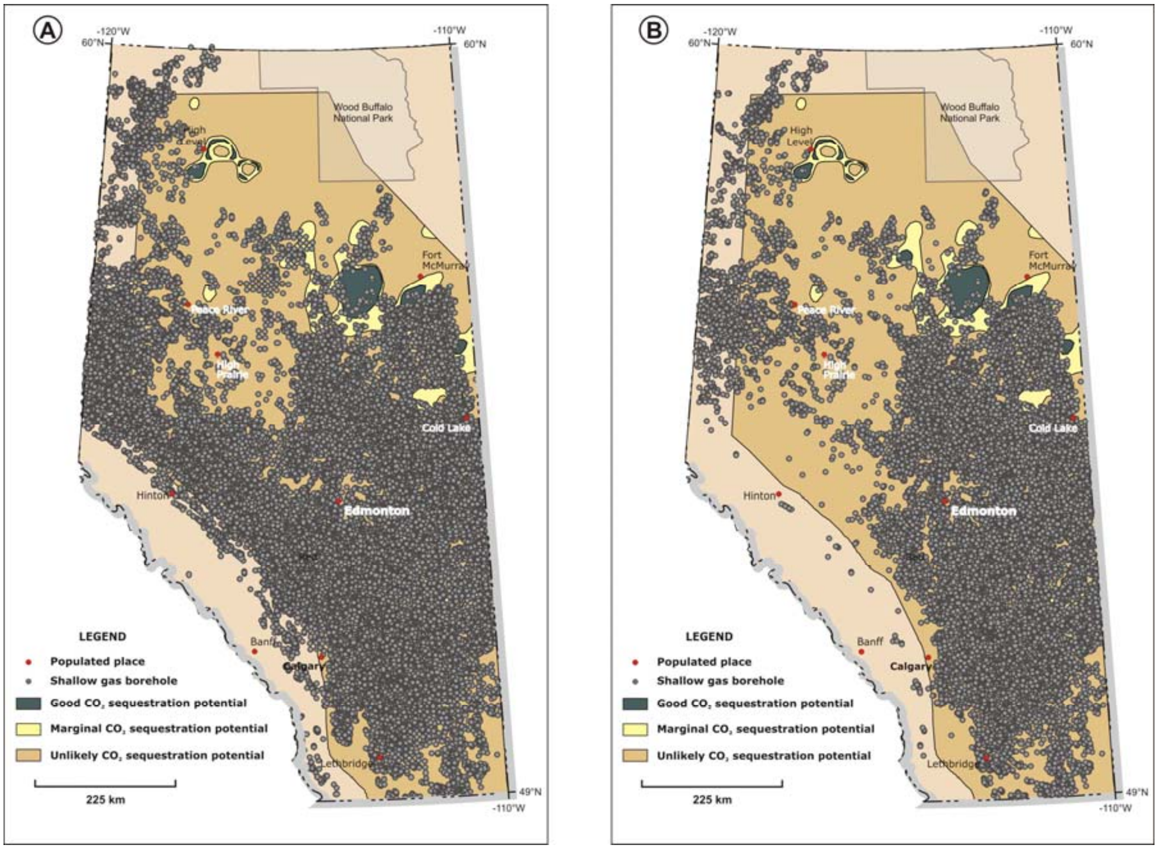

FIGURE 17. A) Distribution of 62,662 shallow gas boreholes drilled between 1904 and 2008. and B) Distribution of 36,764 filtered shallow gas boreholes used in P-T analysis to determine sequestration potential (ERCB, 2008). The locations are superimposed over modeled sequestration potentials determined for 300 m depth (as shown in Fig. 16b).

Figure 18 shows a plot of BHT vs. depth for 121 shallow gas pools (extracted from the 2008 ERCB database) that meet P-T requirements for CO_2 stability. The plot assumes that pore pressures within individual reservoirs increase with depth according to the hydrostatic pressure gradient (~9.8 kPa m^{-1}). The 121 screened wells are clustered in the Fort McMurray and Cold Lake areas, a distribution which generally coincides with the model predictions of areas having good-to-marginal potentials for CO_2 sequestration as gas hydrate (Figure 19). Note that as shown in Figure 18, P-T conditions for many of the candidate gas pools are very close to the CO_2 hydrate stability threshold for fresh water (0 ppt salt). If pore water salinity of 20 ppt is assumed for these reservoirs, then approximately half of the candidate gas pools would fall outside of the CO_2 hydrate stability field, and no sequestration potential would exist at these sites.

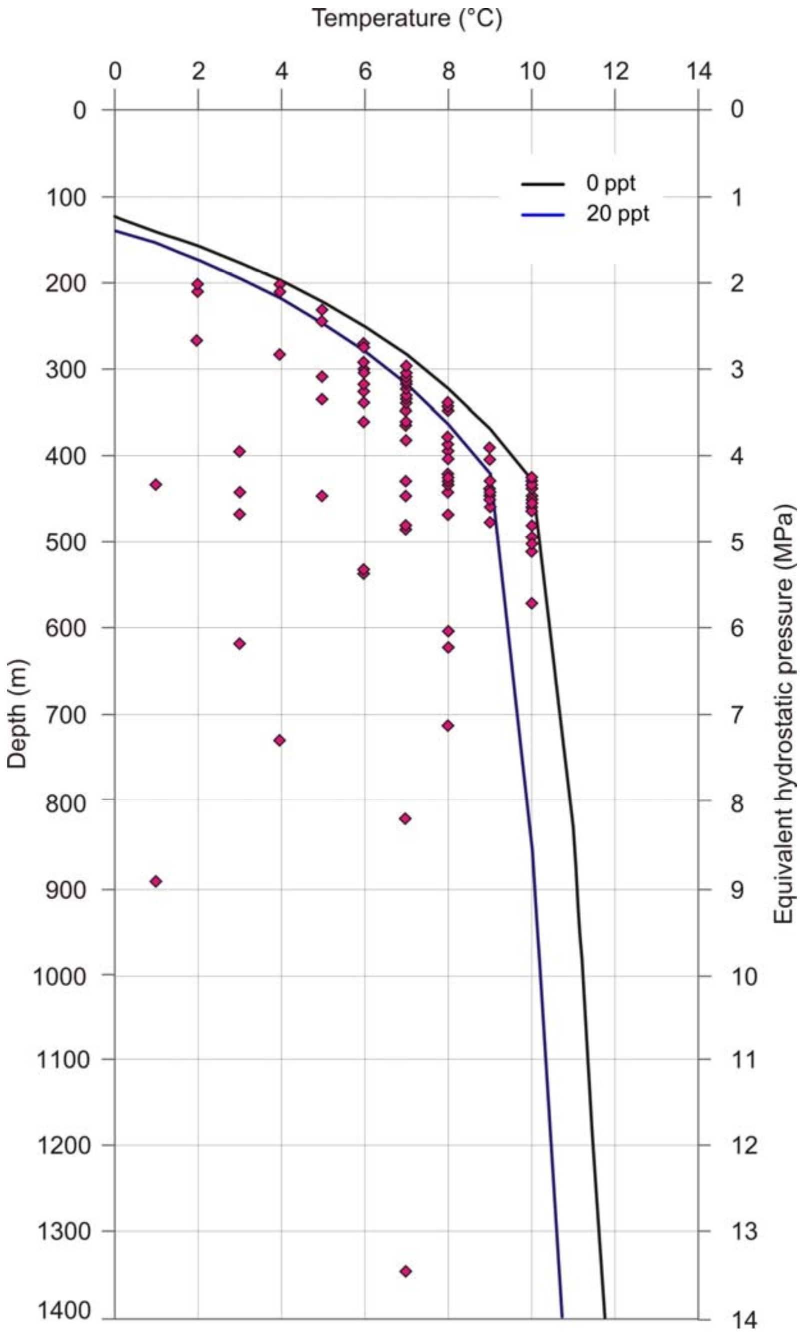

FIGURE 18. Temperature-depth (pressure) data for a subset of 121 industry boreholes which meet P-T criteria for CO_2 hydrate stability in fresh water (0 ppt). Approximately half of the candidate pools would not support stable CO_2 hydrate if pore water salinity of 20 ppt is assumed.

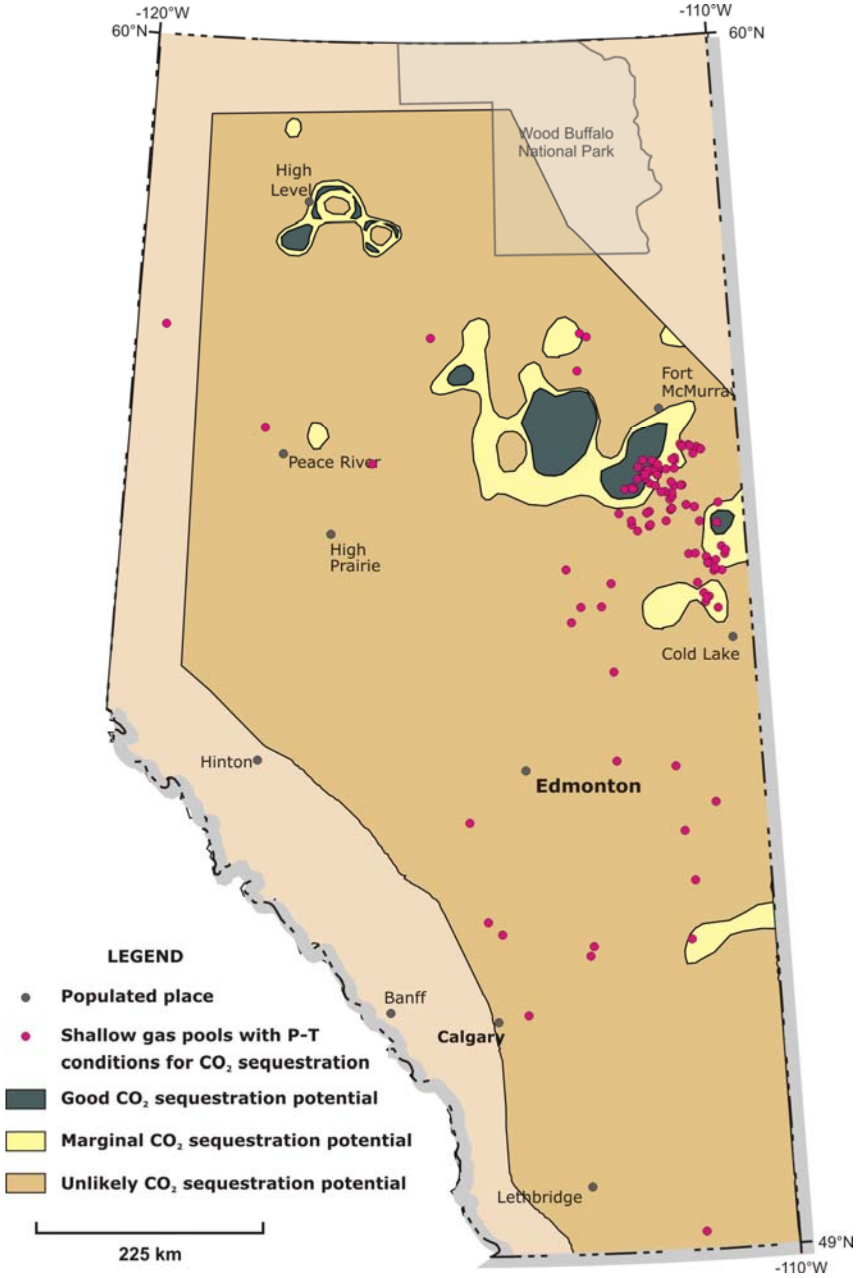

FIGURE 19. Distribution of shallow gas pools which meet P-T criteria for CO_2 hydrate stability (0 ppt salinity assumed), superimposed on model predictions of regional potentials for CO_2 sequestration as gas hydrate at 300 m depth.

The comparatively small number of industry boreholes to the west and north of Fort McMurray emphasizes the requirement for more detailed study within these areas (particularly the need for more precise measurements of ground temperature vs. depth) in order to clarify the geographic extent of potential CO_2 sequestration opportunities in this region. In addition, the acquisition of reliable information about pore water salinity of candidate geologic reservoirs will be critical to the evaluation of CO_2 sequestration potentials on site-by-site basis. Some questions have been raised regarding the quality of bottom hole temperature data in the AEUB database (Majorowicz, 2006; Bachu and Burwash, 1991). Many of the wells report temperatures much higher than would be expected for the reported depth. Possible explanations for these observations include human error in the data collection, or hydrogeological disturbances such as upward migration of warmer groundwater from depth (Bredehoeft and Papadopulos, 1965; Reiter, 2005).

Also present, although much less frequently, are very low pool temperatures for the reported depths (Figure 18, cluster of points with reported temperatures ranging from 1°C to 3°C). These low temperatures at depths up to ~550 m imply anomalously low geothermal gradients (less than 10°C/km). However, estimated geothermal gradients for the northeastern portions of Alberta (Figure 13b) are generally in the range of 15-35°C/km (Bachu and Burwash, 1994). Locally-anomalous ground temperatures at depth could be explained by existence of paleopermafrost in these areas, which has been inferred but not yet proven, or may be due to the presence of significantly cooler near-surface ground temperatures arising from site-specific conditions. Sources of measuring error, such as poor calibration of instruments or poor measuring procedures, could also account for some of these anomalous values.

The uncertainty regarding the accuracy of reported bottom hole temperatures has significant implications for the assessment of regional potentials for CO_2 sequestration as gas hydrate. If observed BHTs tend to over-estimate actual reservoir temperatures, then there may be considerably more gas pools in Alberta having P-T conditions favourable to the formation of stable CO_2 hydrate. A very limited number of precise temperature logs have been acquired at selected Alberta wells, which more accurately describe geothermal conditions within some potential candidate reservoirs. The utility of these precise logs for assessing CO_2 hydrate sequestration potentials is considered in the following section.

8. CO_2 STABILITY ANALYSIS USING PRECISE WELL LOGS

Investigations of the deep thermal regime of the Alberta portion of the WCSB began in the 1980's and continue today (e.g. Majorowicz et al., 1985; Majorowicz et al., 2006). During this time, precise temperature measurements have been made at selected sites throughout Alberta, from which deep temperature profiles have been generated (J.A. Majorowicz, pers. comm. 2010). Figure 20 presents precise temperature logs at 18 wells in the Fort McMurray/Cold Lake area, for which our modeling suggests the greatest potential to sequester CO_2 as hydrate (Figure 21). The temperature values were acquired using a thermistor probe calibrated to 0.03°C absolute accuracy. Measurements were taken in abandoned wells at discrete intervals ranging from 2 to 5 m, to depths of up to ~340 m. These wells had remained undisturbed for many years, therefore we have assumed that the water in the well is in thermal equilibrium with the surrounding rock mass.

Unfortunately, none of the 18 well sites are located within the areas predicted to have good sequestration potential, therefore it is impossible to verify our predictions of ground temperature at depth in these areas. Two well sites (N and R), are located in an area just south of Fort McMurray for which our modeling has predicted a "marginal" sequestration potential (Figure 21). The precise temperature log for site N (Figure 20e) falls well within the P-T stability field for CO_2 hydrate in fresh water. The CO_2 hydrate stability region begins at a depth of ~210 m with a temperature of ~4.3°C and, when extrapolated linearly along the assumed geothermal gradient, extends to a depth of ~500 m at a temperature of ~10°C. This provides a total target zone thickness of ~290 m within which stable CO_2 hydrate may be formed. Meanwhile, the precise temperature log for site R, located only 25 km to the north of site N, suggests no potential exists for CO_2sequestration as gas hydrate, because ground temperatures at depth are well outside the P-T envelope for CO_2 hydrate stability. The remaining 16 wells were located within areas for which our modeling predicts "unlikely" or "no" potential for CO_2 sequestration as gas hydrate (with the exception of site G, which may have marginal potential at ~300 m depth). The precise temperature logs confirm the model predictions of little or no sequestration potential at these sites.

Available precise temperature data illustrate the local variability of geothermal conditions in the region and highlight the importance of high quality ground temperature information for evaluating CO_2 hydrate sequestration potentials within particular areas of interest. The acquisition of additional precise temperature logs in areas for which significant sequestration potentials are indicated must be a priority in any future assessment of geological storage of CO_2 as gas hydrate.

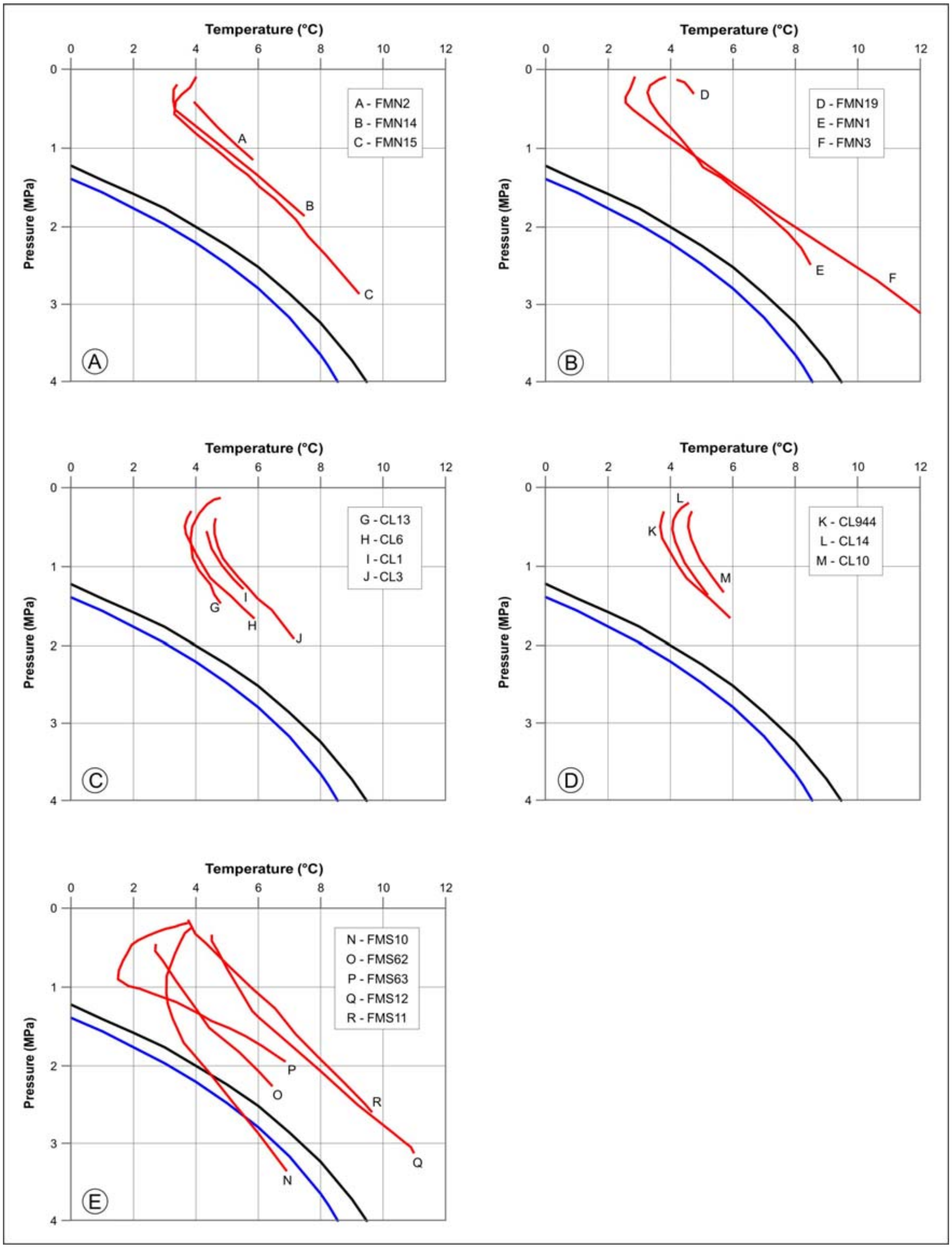

FIGURE 20. Precise temperature logs obtained using portable logging equipment for sites in: A and B - area north of the Fort McMurray, C and D - area around Cold Lake, and E - area south of Fort McMurray (J.A. Majorowicz, pers. comm. 2010). Data were collected between 1993-1997, except for E which were collected during the autumn of 2005. CO_2 hydrate stability curves for fresh pore water (black) and a pore water salinity of 20 ppt (blue) are also presented.

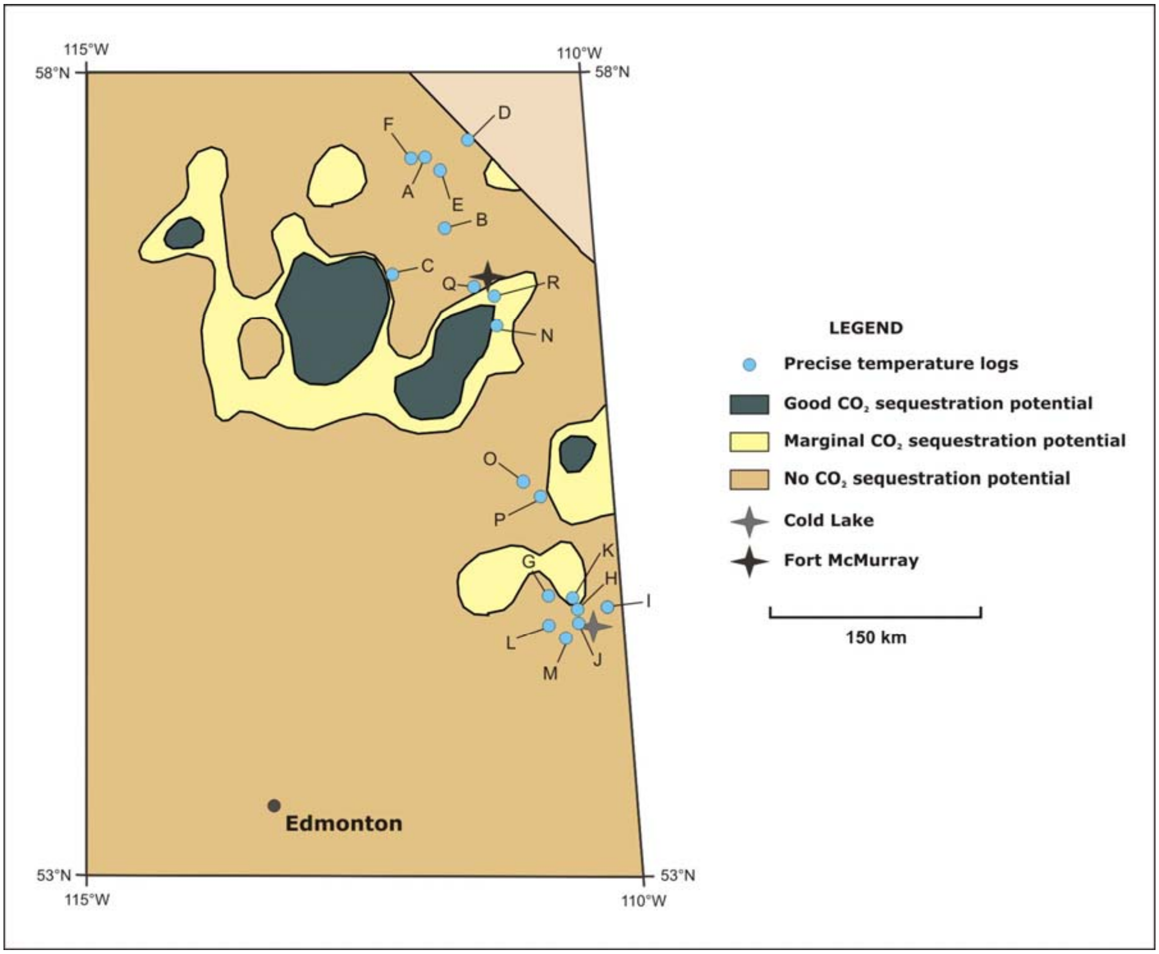

FIGURE 21. Location of precise temperature logs presented in Figure 20 superimposed on model predictions of regional potentials for CO_2 sequestration as gas hydrate at 300 m depth.

9. INFLUENCE OF PORE WATER SALINITY ON CO_2 HYDRATE STABILITY

The assessment of regional potentials for geological sequestration of CO_2 as gas hydrate must consider the possible influences of these major salt deposits on local/regional pore water geochemistry, particularly as affects on the pore water salinity and CO_2 hydrate stability. Clearly, the presence of substantially elevated pore water salinities can significantly reduce or even eliminate CO_2 sequestration potentials locally (Figure 6). However, given the limited amount of available sample data, it is unclear to what extent these large salt deposits have influenced the pore water geochemistry of adjacent or nearby reservoir sediments.

Figure 22 shows the geographic extents of the major salt formations, Upper and Lower Lotsburg deposits, the Cold Lake Formation, and the Prairie Evaporite Formation, within the Fort McMurray/Cold Lake study area.

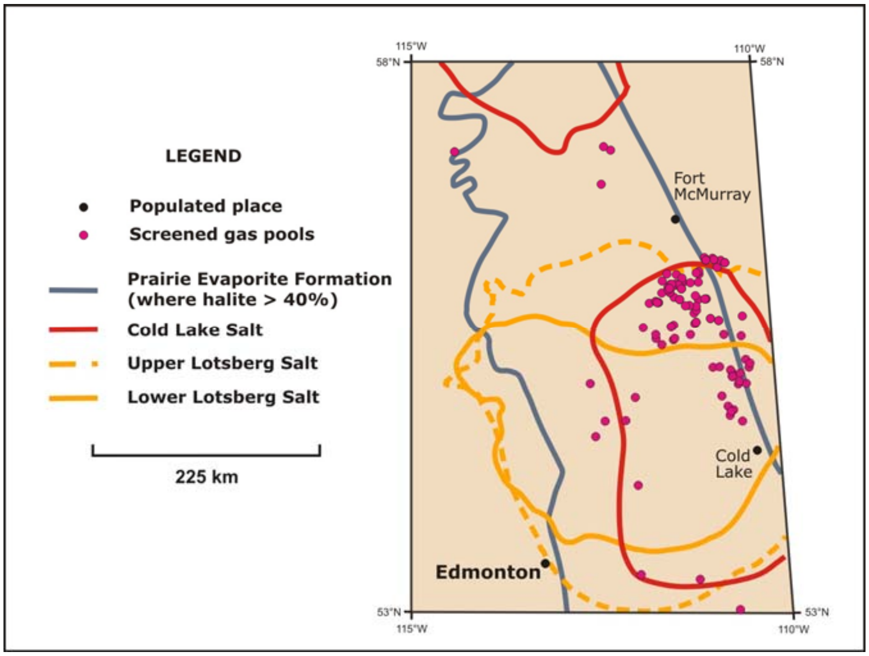

FIGURE 22. Major salt formations in the Fort McMurray/Cold Lake region of Alberta (from Grobe, 2000).

Both the Lotsberg formation (~800 m) and the Cold Lake formation (600 m to 2300 m) are situated considerably below the targeted 300-400 m CO_2 injection interval, and therefore the elevated porewater salinity in these formations is unlikely to affect CO_2 hydrate stability within any overlying reservoirs. However, the over-burden thickness above the Prairie Evaporite Formation ranges from about 2000 m in south-central Alberta, and thins to about 300-400 m in the Fort McMurray area (Figure 23). Therefore, in the general vicinity of Fort McMurray, this relatively shallow salt deposit lies close to or within the potential target interval for CO_2 injection and sequestration as gas hydrate. Information about pore water salinity based on electrical conductivity measurements of formation water at the sequestration target depths was extracted from a geochemical database compiled for the Athabasca Oil Sands area (Lemay, 2002). Salinity values range from near 0 ppt in Quaternary sediments, to ~30 ppt in the Colony, Grand Rapids and Viking formations (Table 1). It is also important to note that salinity is variable not only between different formations but also within a particular formation, as in the case of the Grand Rapids formation where salinity values of between 3.8 ppt and 32.1 ppt were reported.

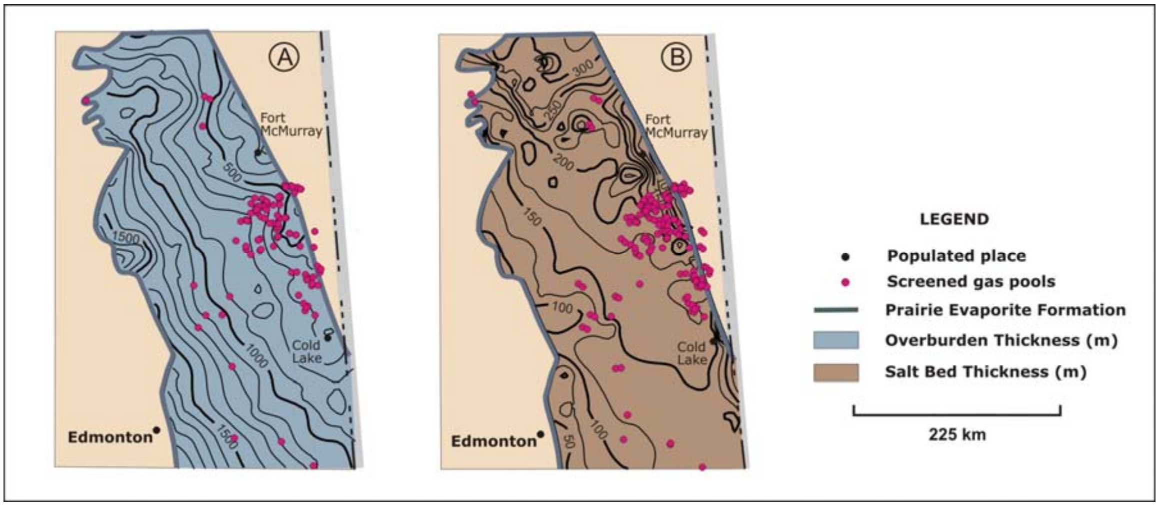

FIGURE 23. Overburden thickness (A) and salt bed thickness (B) of the Prairie Evaporite salt formation (from Grobe, 2000).

Table 1. Conductivity and salinity values for formation water at potential CO_2 sequestration target depths from selected wells in the Athabasca Oil Sands (in situ) area of Alberta (Lemay, 2002).

Formation	Completion depth top (m)	Completion depth bottom (m)	Field conductivity (µS/cm)	Salinity (ppt)	Site	Latitude (°N)	Longitude (°W)
Clearwater	242.0	250.0	11070	7.1	41	55.6860	111.1050
Clearwater	256.0	260.5	11120	7.1	43	55.6863	111.1790
Clearwater	261.5	267.0	9790	6.3	40	55.6855	111.2622
Colony	319.7	320.4	36800	33.7	45	54.7682	112.1488
Colony	335.0	336.0	52600	23.5	46	54.9909	112.2229
Grand Rapids	290.0	291.5	37300	23.9	38	55.0893	112.3380
Grand Rapids	304.8	305.7	22200	14.2	44	54.6706	110.3907
Grand Rapids	311.7	313.2	5880	3.8	39	55.2343	111.5530
Grand Rapids	314.0	315.0	50100	32.1	36	54.7797	111.8801
Quaternary	227.5	230.6	492	0.3	33	55.7144	112.1879
Quaternary	275.5	284.7	593	0.4	34	55.2939	110.7997
Quaternary	290.0	300.0	689	0.4	35	55.3413	111.0317
Viking	249.9	252.4	48600	31.1	37	55.9094	111.8828
Viking	270.5	271.5	41100	26.3	42	55.0054	111.5721

10. RESERVOIR POROSITY AND PERMEABILITY

Figures 24 and 25 present two geological cross-sections for the Fort McMurray area, as determined by Bachu et al. (1993). Superimposed upon the geological information are contour lines at 300 m and 400 m below the ground surface, which bound the potential target interval for CO_2 sequestration as determined in Sections 5 and 6. Although, more detailed geological information is required to fully evaluate potential candidate reservoirs for CO_2 sequestration as gas hydrate, these cross-sections provide a good starting point from which to assess the general suitability of potential target stratigraphic units.

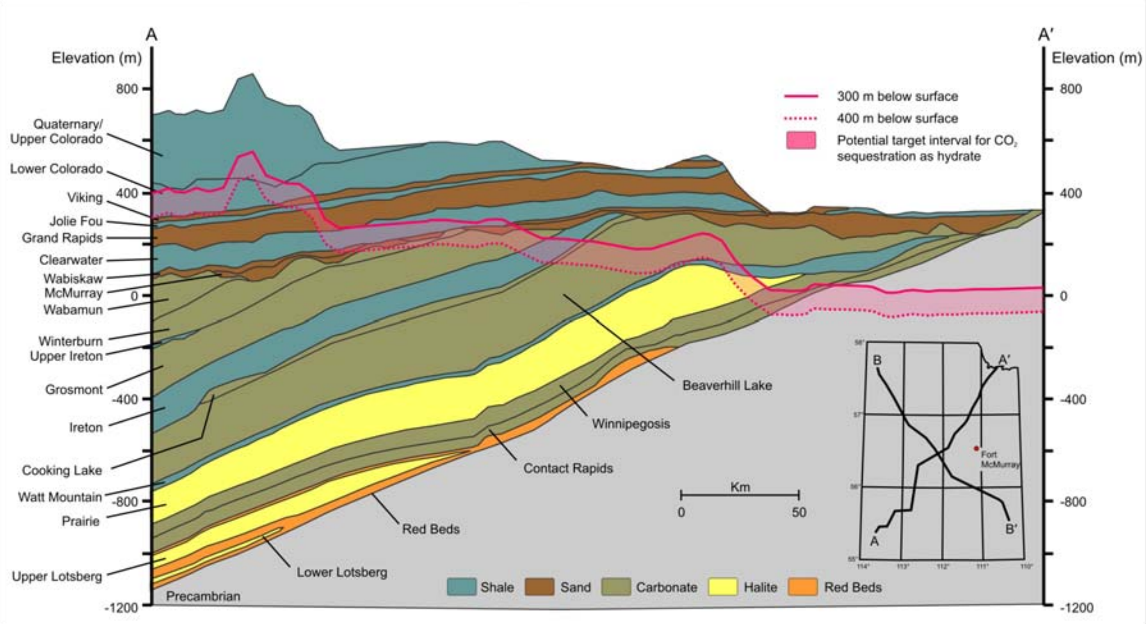

FIGURE 24. Geological cross-section showing general lithology and structure of geological materials (from Bachu et al., 1993), and potential target interval for CO_2 sequestration as gas hydrate along transect A-A' (inset) near Fort McMurray, Alberta.

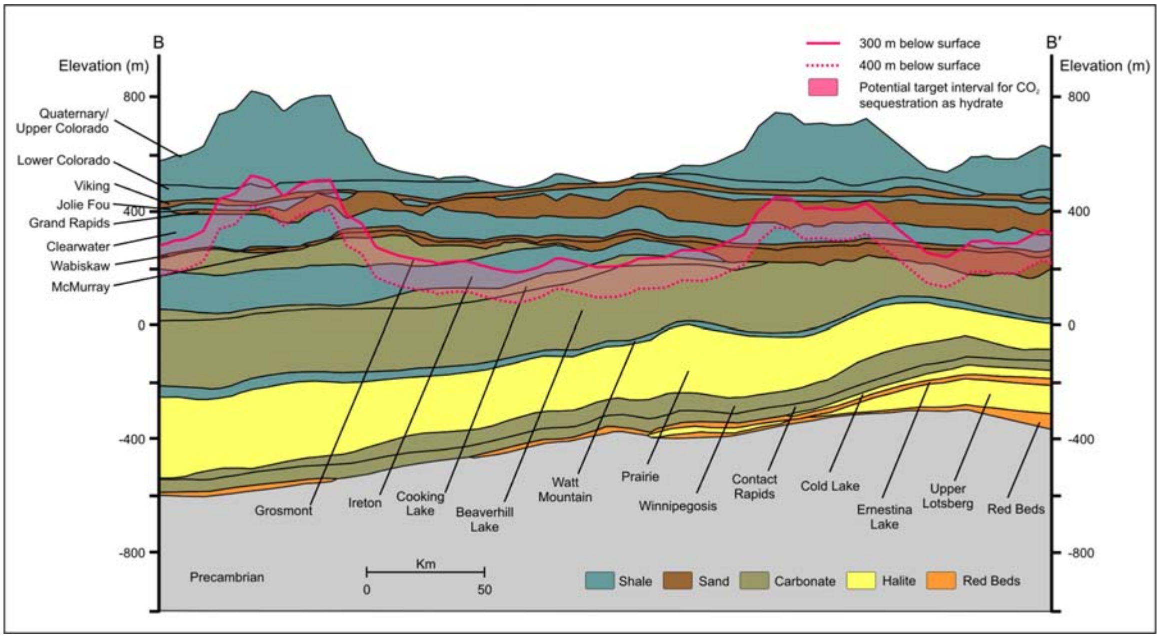

FIGURE 25. Geological cross-section showing general lithology and structure of geological materials (from Bachu et al. 1993), and potential target interval for CO_2 sequestration as gas hydrate along transect B-B' (inset) near Fort McMurray, Alberta.

Bachu et al. (1993) determined regional-scale permeability and porosity values for various stratigraphic units in northeastern Alberta, the region identified by our modeling as having the greatest potential for CO_2 sequestration as gas hydrate. Permeability of the units was determined using two approaches which rely on data collected at different vertical spatial scales. The drillstem test method obtains permeability values at the well-scale by sampling a large volume of rock *in situ* and encompasses unit variability, such as small fractures or small shale lenses, which may be missed by larger-scale sampling methods. The geometric average permeability presented in Table 2 is considered to be a reasonable best estimate of well-scale permeability values (Bachu et al., 1993). A second estimate of permeability for each unit was determined using core-plug analysis. A scaling-up procedure was required to extrapolate this local data to a well-scale and then to a regional-scale level (Bachu and Undershultz, 1992) (Table 3). Data from core plugs characterize the movement of fluids through pore space only, and do not account for the movement of fluids through larger features such as fractures.

Table 2. Regional-scale permeability measurements obtained from drillstem tests (from Bachu et al., 1993, Table 3).

Hydrostratigraphic unit	No. tests	Minimum (mD)	Maximum (mD)	Geometric average (mD)	Dominant material	Hydro-stratigraphy
Viking	51	0.046	5207	18.59	Shale	Aquifer
Grand Rapids	416	0.008	6712	41.73	Sand	Aquifer
Wabiskaw	200	0.009	5464	8.41	Sand	Aquifer
McMurray	365	0.002	8085	13.66	Sand	Aquifer
Winterburn	34	0.0134	1900	9.81	Carbonate	Aquifer
Grosmont	55	0.028	1591	10.75	Carbonate	Aquifer
Cooking Lake	7	0.003	1556	1.80	Carbonate	Aquifer
Beaverhill Lake-Cooking Lake	22	0.036	1122	91.16	Carbonate	Aquifer
Contact Rapids-Winnipegosis	31	0.001	272	1.03	Carbonate	Aquifer

Table 3. Regional-scale permeability measurements obtained from core analysis (from Bachu et al., 1993, Table 4).

Stratigraphic unit	No. tests	Minimum permeability (mD)	Maximum permeability (mD)	Geometric averaged permeability (mD)	Dominant material	Hydro-stratigraphy
Viking	12	26.30	5960	697.86	Shale	Aquifer
Grand Rapids	101	0.04	6270	488.12	Sand	Aquifer
Clearwater	30	0.48	4720	180.60	Shale	Aquitard
Wabiskaw	269	0.10	6900	254.50	Sand	Aquifer
McMurray	382	0.01	9980	262.81	Sand	Aquifer
Winterburn	39	0.06	1370	14.53	Carbonate	Aquifer
Grosmont	178	0.02	6870	14.83	Carbonate	Aquifer
Cooking Lake	6	0.25	96	6.50	Carbonate	Aquifer
Beaverhill Lake	34	0.01	10200	39.67	Carbonate	Aquifer
Prairie	9	0.01	9	0.20	Halite	Aquiclude
Winnipegosis	43	0.01	175	0.43	Carbonate	Aquifer
Contact Rapids	6	0.01	2	0.05	Carbonate	Aquifer

Comparison of permeability estimates obtained using the two different methods (Tables 2 and 3), show that estimates obtained from core analysis are generally one order of magnitude higher than those obtained with drill-stem testing. Bachu et al. (1993) discuss this discrepancy and suggest that the core analysis method may lead to artificially high values due to the core having been disturbed and depressurized prior to measurement. Furthermore, it has been found that higher permeability values are measured when air is used as the fluid in the core plug method instead of water or brine. At present, there is no recognized methodology for reconciling the inconsistency between the values obtained by the two methods (Bachu et al., 1993).

Should the investigation of the option for geological sequestration of CO_2 as gas hydrate within these NE Alberta formations advance beyond the feasibility study level, more precise measurements of permeability would be required. For the current study, these data suggest that in general, the permeability of sedimentary formations is suitable for sustained injection of CO_2 and subsequent *in situ* formation of CO_2 hydrate.

Bachu et al. (1993) obtained porosity estimates for the various stratigraphic units using the core-plug method, and determined that formation porosities ranged from about 31 to 35% (Table 4). These comparatively high porosities are very favourable for the sequestration of CO_2 as gas hydrate, representing a substantial storage capacity per unit volume of reservoir rock.

Bachu et al. (1993) also classified the hydrostratigraphy of northeast Alberta formations into three categories, following definitions provided by de Marsily (1986, p.115): An aquifer is a layer, formation, or group of formations saturated with water and sufficient permeability to allow water withdrawal; an aquitard is a less permeable unit from which water cannot be extracted through wells, but where the flow does feed adjacent aquifers through vertical leakage; and an aquiclude is a unit with very low permeability and does not give rise to any appreciable leakage.

Table 4. Regional-scale porosity measurements obtained from core analysis (from Bachu et al., 1993, Table 6).

Stratigraphic unit	No. wells	Minimum porosity	Maximum porosity	Arithmetic averaged porosity	Dominant material	Hydro-stratigraphy
Viking	16	0.27	0.38	0.33	Shale	Aquifer
Grand Rapids	285	0.09	0.42	0.35	Sand	Aquifer
Clearwater	53	0.15	0.40	0.31	Shale	Aquitard
Wabiskaw	1558	0.06	0.42	0.31	Sand	Aquifer
McMurray	4822	0.02	0.43	0.32	Sand	Aquifer
Winterburn	56	0.04	0.33	0.20	Carbonate	Aquifer
Grosmont	193	0.02	0.36	0.15	Carbonate	Aquifer
Cooking Lake	19	0.01	0.36	0.26	Carbonate	Aquifer

Beaverhill Lake	1057	0.003	0.42	0.31	Carbonate	Aquifer
Prairie	10	0.02	0.33	0.08	Halite	Aquiclude
Winnipegosis	46	0.01	0.38	0.09	Carbonate	Aquifer
Contact Rapids	6	0.01	0.10	0.05	Carbonate	Aquifer

An additional consideration regarding the properties of a particular geological unit targeted for CO_2 sequestration is that the formation waters be sufficiently isolated from adjacent fresh water aquifers from which the domestic water supply is extracted. Alberta has a good supply of near surface potable water, therefore most domestic wells are quite shallow. Wells are considered "deep" when they exceed 15 m (Lebedin et al., 2000), which is well above the target depths of 300 to 400 m for sequestration.

11. SUMMARY OF OPPORTUNITIES FOR CO_2 SEQUESTRATION AS GAS HYDRATE IN ALBERTA

Figure 16 shows the results of a regional-scale modeling exercise which predicts areas where pressure-temperature conditions in the underlying sediments may be conducive to the formation of stable CO_2 hydrate. A cumulative area of approximately 9200 km^2 is classified as having "good" potential for sequestration, and approximately 23,700 km^2 is classified as having "marginal" potential. P-T data suggest that the zone of CO_2 hydrate stability within these zones is at least 100 m in thickness.

An evaluation of the generalized properties of potential target reservoirs suggests that overall, adequate porosity is available for storage of substantive amounts of CO_2 as hydrate, and that reservoir permeability is sufficiently high to support reasonable CO_2 injection rates and efficient reservoir filling. Although less well understood, available data suggest that in general, pore water salinity values within these reservoirs will not excessively limit the formation and maintenance of stable CO_2 hydrate.

The following first-order estimate of the amount of CO_2 that could be sequestered as gas hydrate in NE Alberta assumes an average thickness of the sequestration interval of 50 to 100 m and an average reservoir porosity of 27%. Based on these constraints the total pore volume available for the formation of stable CO_2 hydrate is:

Areas with good potential	$9.2\times10^{9}\ m^{2} \times 100\ m \times 0.27 = 2.5\times10^{11}\ m^{3}$
Areas with marginal potential	$2.3\times10^{10}\ m^{2} \times 50\ m \times 0.27 = 3.1\times10^{11}\ m^{3}$

Assuming a CO_2 density of 0.3 $tonne\cdot m^{-3}$ of hydrate (based on the theoretically optimum molecular ratio for CO_2 hydrate of $5.75H_2O:1CO_2$) we calculate the maximum CO_2 storage this represents for:

Areas with good potential $2.5\times10^{11}\ \text{m}^3 \times 0.3\ \text{tonne}\cdot\text{m}^{-3} = 7.5\times10^{10}$ tonne

or 75 Gt

Areas with marginal potential $3.1\times10^{11}\ \text{m}^3 \times 0.3\ \text{tonne}\cdot\text{m}^{-3} = 9.3\times10^{10}$ tonne

or 93 Gt

However, field and laboratory data, as well as reservoir modeling, suggest that 100% pore occupancy by gas hydrate is not practically achievable. For example, the gas hydrate bearing intervals at the Mallik research site in Canada's Mackenzie delta typically show pore occupancy by gas hydrate in the range of 50-90%, (Dallimore and Collett, 1999, 2005.). A target pore occupancy of 50% of the available pore volume has been assumed as a basis for estimating the gross CO_2 sequestration capacity of the candidate reservoirs identified in this analysis. This reduces the gross CO_2 sequestration capacity for areas having "good" potential to:

Capacity for areas with good potential: 75 Gt × 0.50 = 37.5 Gt

For areas designated as "marginal", uncertainties regarding the specification of ground temperatures make it likely that much of the area may in fact be unsuitable for CO_2 sequestration as gas hydrate due to warmer than expected ground temperatures. On this basis we have further reduced our estimate of the overall sequestration capacity for "marginal" areas by an additional 50%.

Capacity for areas with marginal potential: 93 Gt × 0.50 × 0.50 = 23.5 Gt

Therefore, the estimated total Alberta capacity for CO_2 sequestration as gas hydrate in areas designated as having good or marginal potentials is 61 Gt.

Based on the CO_2 emissions data presented in Figure 7, this capacity would be sufficient to sequester 100% of the combined annual CO_2 output from Alberta's fossil fuel industries, and electrical and heat generation plants (104 Mt) for a period of 580 years (based on 2010 data, Fig. 7). While these numbers derive from a cursory analysis and should be interpreted with caution, this initial study suggests that a very large potential for CO_2 sequestration as gas hydrate exists in the geological formations of Alberta, with a potential capacity to store up to 61 Gt or more of CO_2.

Although considerable new research is required to advance from simple geological assessments towards a possible future demonstration project, a number of factors suggest that the additional work is merited. In particular, many of the relevant technologies for the capture, transport, and injection of CO_2 into deep geologic structures have been developed for, or adapted from, commercial Enhanced Oil Recovery (EOR) applications and a limited number of coal bed methane and/or CO_2 sequestration pilot projects (Gunter et al., 2010) Furthermore, numerical reservoir simulations conducted at the Alberta Research Council have identified no absolute constraints to the long-term injection and formation of CO_2 hydrate in simulated reservoirs having P-T conditions suitable for CO_2 sequestration as gas hydrate (Uddin et al., 2008).

12. CLIMATE CHANGE CONSIDERATIONS

Global Circulation Models (GCMs) predict that global atmospheric temperatures will continue to increase during the next century. Predictions vary regarding magnitudes and rates of change but the models agree that, in general, the higher latitudes will experience considerably greater warming of mean annual air temperatures (MAAT) than will equatorial regions. The Canadian Centre for Climate Modeling and Analysis (CCCma) employs atmospheric and coupled climate models to generate predictions of future trends in mean annual air temperature across Canada at various spatial scales. Figure 26 presents CCCma predictions of increases in mean annual air temperature for the period 2041-2060 (relative to 1971-1990) using the CCCma's second-generation Coupled Global Climate Model (CGCM2). Mean annual air temperature in the Fort McMurray area is predicted to increase by 2.5-3.0°C during the next 40 to 60 years. It is therefore very important to consider how this potential increase in atmospheric temperature will affect ground temperatures at the depth intervals (300-400 m) targeted for CO_2 sequestration as gas hydrate.

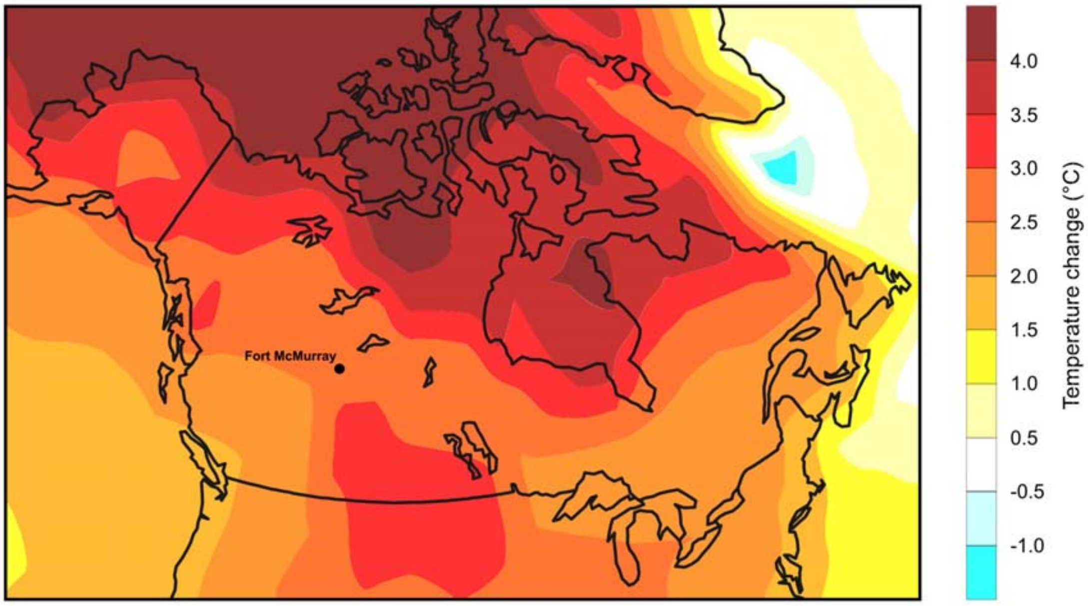

FIGURE 26. Change in annual mean air temperature in 2041-2060 relative to 1971-1990 as simulated using CGCM2 by the Canadian Centre for Climate Modeling and Analysis.

A transient finite-element ground thermal model T-ONE (Goodrich 1978, 1982) was configured to predict the evolution of ground temperatures at depth in response to a specified scenario of climate warming. Generalized descriptions of lithology, vegetation cover, and near-surface soil moisture content assumed to be representative of terrain in the Fort McMurray area were used as a basis for the assignment of physical model parameters (e.g. thermal conductivity, heat capacity, etc.) following Wright et al. (2003). A present-day MAAT of 0.2°C was assumed for the Fort McMurray region, based on the 1961-1990 Climate Normals (Environment Canada, 1994). The simulation was run until thermal equilibrium was achieved between the atmospheric climate and the ground thermal regime, after which an instantaneous atmospheric warming (step-change) of 3.0°C was applied to represent a warmer future climate. The model was allowed to run forward into the future for sufficient time to affect a 1°C increase in ground temperatures at depth. According to the modeling, the time required to realize a 1°C increase in ground temperature at 300 m depth varied from ~1000 years for high conductivity sediments (e.g. sandstone/dolomite) to ~2000 years in sediments of relatively low thermal conductivity (e.g. siltstone/shale). These time frames may reasonably be considered as acceptable residency periods for CO_2 sequestered as gas hydrate, depending upon the prevailing sense of urgency with which the problem of climate change is perceived.

This cursory modeling exercise demonstrates the importance of considering the influence of ground surface characteristics, particularly the buffering effects of vegetation and snow cover on the exchange of heat between the atmosphere and the ground at depth. The modeling suggests that considerable local variability exists both with regard to ground temperatures at depth and the rate of ground temperature response to climate warming, depending on the nature of ground surface conditions. These factors should be included in any comprehensive assessment of regional potentials for geological sequestration of CO_2 as gas hydrate.

13. ACCESSIBILITY - PIPELINES

Although there are numerous technology and engineering issues related to the transportation, injection, and monitoring of CO_2 for geological sequestration applications, a detailed investigation of these issues is beyond the scope of this study. However, it is worth noting that Alberta already possesses much of the infrastructure necessary for CO_2 transportation and storage, and also has well-developed technologies and protocols for CO_2 injection and monitoring due to significant industry involvement in EOR. Maps of existing oil and natural gas transportation infrastructure (Figures 27 and 28) reveal a dense network of pipelines within Alberta and neighboring Saskatchewan, some of which could be adapted for transporting carbon dioxide gas from stationary CO_2 generation sites to potential sequestration sites.

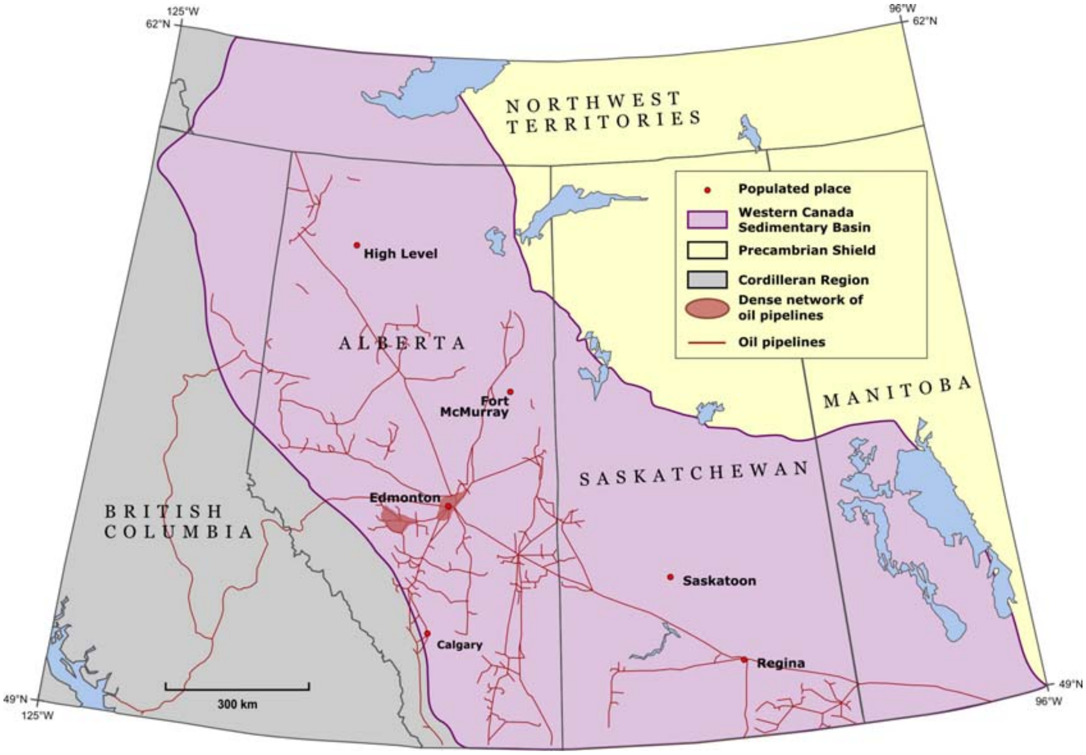

FIGURE 27. Distribution of oil pipelines in the WCSB.

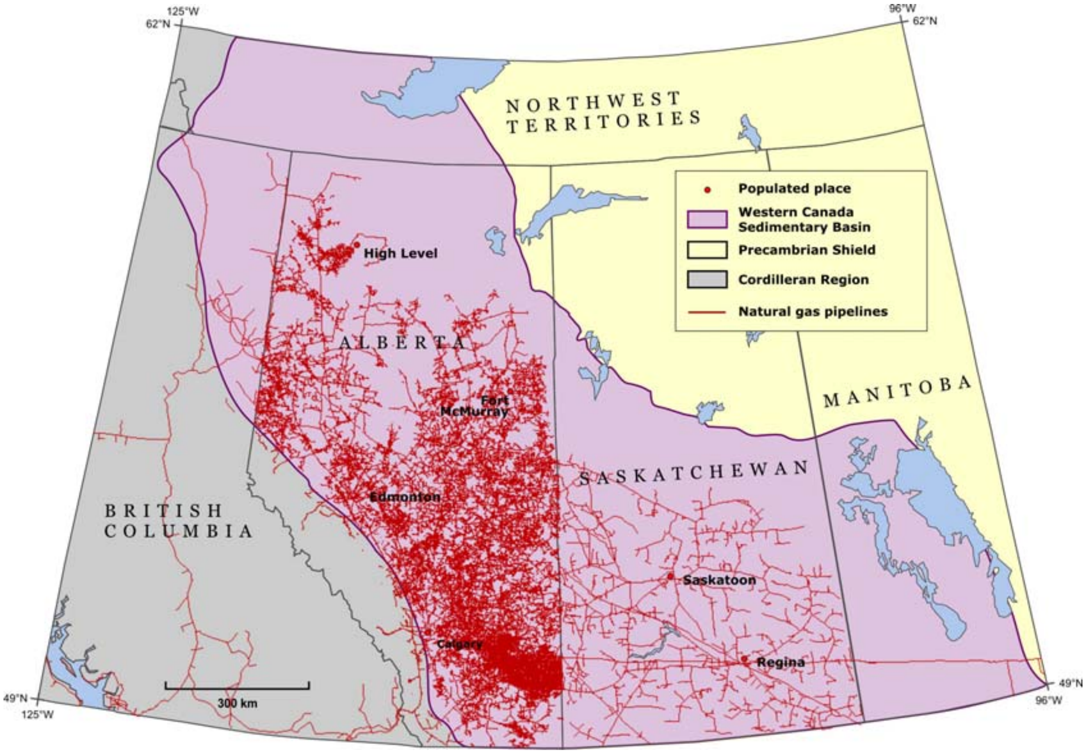

FIGURE 28. Distribution of natural gas pipelines in the WCSB.

14. CONCLUSIONS

The Alberta portion of the WCSB has been investigated with respect to the potential for the geological sequestration of CO_2 as gas hydrate. The areas north of Cold Lake and south/southwest of Fort McMurray have shown significant sequestration potential. From this analysis, five major conclusions can be drawn:

1) Sequestering CO_2 as hydrate is more desirable than CO_2 storage as a liquid or a super-critical fluid, given that solid-phase gas hydrate is a more efficient storage medium and is more likely to remain where it is formed.

2) The relatively porous and permeable sediments of the WCSB present ideal candidate basins for injecting and storing CO_2 as hydrate. Based on a coarse-resolution geothermal analysis, it is estimated that the gross amount of CO_2 that could be sequestered as gas hydrate in Alberta is approximately 61 Gt.

3) Target injection intervals (300-400 m depth) for candidate geological reservoirs are characterized by P-T conditions favourable to the formation and maintenance of stable CO_2 hydrate. The presence of a substantial overburden provides an effective buffer against the propagation of warmer surface temperatures (due to progressive climate warming) into the ground at depth. Modeling predicts a time frame of between 1000-2000 years for a 3°C change in surface air temperature to effect an increase in ground temperature of 1°C at 300 m depth.

4) Many of the relevant technologies for the capture, transport, and injection of CO_2 into deep geologic structures have been developed for, or adapted from commercial EOR applications, and a limited number of coal bed methane and/or CO_2 sequestration pilot projects.

5) This preliminary regional assessment offers a potential new option for the geological sequestration of CO_2 in Canada, however considerable additional work is required to advance this idea from concept to practice. Specifically, the acquisition of more reliable site-specific data (regarding ground surface temperatures and local geothermal gradients, pore water geochemistry, porosity and permeability) would be requisite to the implementation of a small-scale demonstration project in a readily accessible region of northeastern Alberta.

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