CARBON DIOXIDE STORAGE CAPACITY IN UNECONOMICAL COAL BEDS IN ALBERTA: POTENTIAL AND SITE IDENTIFICATION

Topical Report

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EXECUTIVE SUMMARY

Carbon dioxide (CO_2) capture and geological sequestration are both means for reducing anthropogenic CO_2 emissions into the atmosphere that are immediately available and technologically feasible and that are particularly suited for Alberta as a result of its geology. Sequestration of CO_2 in coal seams, concurrent with methane production, is one of the possible means of CO_2 geological sequestration. Cretaceous–Tertiary strata in Alberta contain several coal zones, some of them with potential for coalbed methane (CBM) production and CO_2 sequestration. Thin coal zones in the Edmonton and Belly River Groups have low CO_2 storage potential because they are thin and discontinuous in places. Only the Mannville, Drumheller, and Ardley Coal Zones have significant CBM potential and, therefore, by extension, may have corresponding CO_2 storage potential. Regions suitable for CO_2 sequestration in these coal zones have been defined on the basis of depth, such that potable groundwater resources are protected, and on the basis of CO_2 phase at in situ conditions, i.e., the regions deeper than 300 m where CO_2 is still a gas. The theoretical CO_2 sequestration capacity in these regions was estimated on the basis of CO_2 adsorption isotherms measured on coal samples, and it varies from ~20 $ktCO_2/km^2$ in areas of thin coals to 1260 $ktCO_2/km^2$ in areas of thick coals with high adsorption capacity, for a total of approximately 20 $GtCO_2$. This represents the ultimate sequestration capacity limit that would be attained if there were no other gases present in the coals or they would be 100% replaced by CO_2 and if all the coals would be accessed by CO_2. A recovery factor of less than 100% and a completion factor of less than 50% reduce the theoretical sequestration capacity to an effective sequestration capacity of only 6.4 $GtCO_2$. However, it is highly unlikely that all the effective CO_2 sequestration capacity in Alberta's coal zones will be utilized because it will be uneconomical to build the necessary infrastructure (pipelines, compressors, and a high density of injection wells) for areas with low sequestration capacity per unit surface. Considering that it is economical to develop the necessary infrastructure only for areas with CO_2 sequestration capacity greater than 200 $ktCO_2/km^2$, then the CO_2 sequestration capacity in coal beds in Alberta is greatly reduced further to a practical capacity of only ~850 $MtCO_2$.

There are no suitable target areas with high CO_2 sequestration capacity in the Mannville Coal Zone. In addition, the Mannville coals would make poor candidates for CO_2 storage because of their depth, low permeability, elevated salinity of formation water that would be produced, the presence of oil and gas reservoirs in this stratigraphic interval that could be contaminated by leaked CO_2, and the absence of major CO_2 sources and potential CO_2 sinks within close distance, which would lower significantly the cost of CO_2 storage operations as a result of scale. In regard to the Drumheller Coal Zone of the Horseshoe Canyon Formation, there are a few very small areas with high capacity in the Three Hills and Carseland areas northwest and east-southeast of Calgary, respectively. The practical CO_2 sequestration capacity in these two areas is 55 $MtCO_2$. These areas are located in the agricultural heartland of Alberta, and CO_2 sequestration with CBM production may raise conflicts with land use. The Drumheller coals in these regions are relatively shallow (close to 300 m depth). CO_2 stored in these coals will likely sterilize shallow coal resources that may become economical for mining at some time in the future, and any leaked CO_2 from these coals will likely contaminate groundwater resources in these agricultural regions. In contrast to the Mannville and Drumheller Coal Zones, the Ardley Coal Zone has a much larger practical capacity for CO_2 sequestration of ~800 $MtCO_2$ in an area of ~3330 km^2 that comprises a large area in the Whitecourt region south of the Athabasca River and a narrow zone in the Pembina area. Both regions are located in forested lands which are less likely to become the object of land use conflicts. Besides the fact that this region is located in a forested area, the low salinity of water in the Ardley coals adds the advantage that produced water does not have to be treated, and it is possible that it could even be discharged at the surface if Alberta Environment regulations are being met. There are no oil or gas reservoirs in the stratigraphic vicinity of the Ardley coals, but there are many large potential CO_2 sinks in deeper oil and gas reservoirs in these areas. Infrastructure built to bring CO_2 from large CO_2 sources in the Edmonton–Lake Wabamun region located to the east will be economical given the large number of potential CO_2 sinks in western Alberta, comprising the Whitecourt and Pembina areas, and the large storage capacity of these sinks. Given the high CBM potential of the Ardley coals, CO_2 could be used in enhanced CBM and oil and gas recovery operations, thus producing additional oil and gas that would significantly increase the economics of CO_2 storage operations. Thus the Ardley Coal Zone in the Whitecourt and Pembina areas of western Alberta should be the primary targets for CO_2 storage in coals in Alberta.

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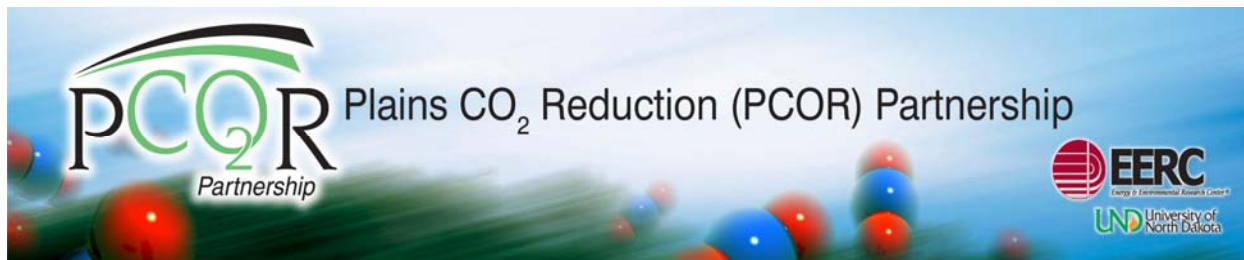
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INTRODUCTION

Most of the solar radiation received by Earth is lost to space by reflection; however, because of the presence of certain gases in the atmosphere, some of the radiative heat is trapped in the atmosphere, warming it and raising Earth's surface temperature (the so-called greenhouse effect). The most important natural greenhouse gases (GHGs) are water vapor, CO_2, methane (CH_4), nitrous oxide (N_2O), and tropospheric ozone (O_3). A raise in global temperature of approximately 0.4°–0.6°C since the middle of the 19th century has been observed that coincides with a parallel raise in atmospheric concentrations of CO_2 from 280 ppm to more than 360 ppm today and a much more modest raise in methane concentrations. Generally, warming of the atmosphere leads to changes in weather patterns, severe weather events, and melting of glaciers and ice caps, with associated effects of life and society. While a direct causal link between the raise in GHG concentrations in the atmosphere and global warming has not been demonstrated, circumstantial evidence points toward this link, and it has been generally accepted by a broad segment of the scientific community and by policy makers. There is also almost general acceptance that the world cannot wait for definitive answers on this subject and that preventive and mitigating actions have to take place concurrently.

The increase in atmospheric concentrations of CO_2 and methane are attributed to human activity since the beginning of the industrial revolution, more specifically to energy production by burning fossil fuels and land use changes (mainly agricultural expansion on an industrial scale) to satisfy the needs of a global population that increased at accelerated rates. Because of its relative abundance, CO_2 is considered to be responsible for ~64% of the greenhouse effect and the associated climate warming. Methane, although less abundant, is also an important GHG because it has a radiative effect that is 21 times stronger than that of CO_2. To address the effects of global climate change, scientific and policy efforts are focused in three major directions: 1) understanding better the science of climate change, 2) adapting to predicted climate changes, and 3) mitigating the effects of climate change. As a result, reducing atmospheric emissions of CO_2 and methane is one of the main mitigating measures considered by society, with most efforts being focused on reducing CO_2 emissions.

The 1992 United Nations Framework Convention on Climate Change (UNFCCC) states as an objective the "stabilization of GHG concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system," and most countries agreed to voluntarily reduce their GHG emissions (United Nations Framework Convention on Climate Change, 1999a). The Kyoto Protocol, which entered into force on February 16, 2005, set targets and timetables for emission reductions at a level on average 5% below 1990 levels by 2008–2012 (the "Kyoto period") for Annex I Parties (developed and transition economies) (United Nations Framework Convention on Climate Change, 1999b). Canada, which has committed to reduce its CO_2 emissions at 6% below 1990 levels (i.e., at 571 $MtCO_2$/year), ratified the Kyoto Protocol in the fall of 2002 and is the only country in the western hemisphere that has binding commitments for the reduction of atmospheric CO_2 emissions. Although Canada's GHG emissions currently represent only 1.8% of the world total, it has one of the toughest emission reduction targets because, unlike major European countries and Russia, Canada's atmospheric CO_2 emissions increased continuously from 607 $MtCO_2$ in 1990 to 726 $MtCO_2$ in 2000 (a 19% increase), with projected emissions by 2010 of ~810 $MtCO_2$ under a business-as-usual scenario. This represents a projected gap of ~240 $MtCO_2$ toward the end of the Kyoto period.

Reducing anthropogenic CO_2 emissions into the atmosphere involves basically three approaches, expressed best by the modified Kaya identity (Kaya, 1995; Bachu, 2003) that links carbon emissions (C), energy (E), and population (P) and economic growth as indicated by the gross domestic product (GDP):

$$NetC = P \times \frac{GDP}{P} \times \frac{E}{GDP} \times \frac{C}{E} - S_C \qquad (1)$$

In the above relation, *GDP/P* is the per capita GDP, *E/GDP* is the "energy intensity" of the economy, *C/E* is the "carbon intensity" of the energy system, and S_C represents carbon removed from the atmosphere (carbon sinks). In theory, a reduction in atmospheric CO_2 emissions (*NetC*) can be achieved by a combination of the following: a) reducing the population (historically, this happens through famine, plagues, and/or wars), b) reducing the economic output (historically this happens through recessions and/or destruction of infrastructure and/or wars), c) lowering the energy intensity of the economy (i.e., increase in conservation and efficiency of primary energy conversion and end use); d) lowering the carbon intensity of the energy system by substituting lower-carbon or carbon-free energy sources for the current sources; and e) by artificially increasing the capacity and capture rate of carbon sinks. The first two options are both unacceptable and, historically, are local and/or short-lived when they happen. Also, historical evidence shows that, on aggregate, the emission intensity (*C/GDP*) decreased continuously since the beginning of the Industrial Revolution, the carbon removed from the atmosphere (S_C) decreased slightly as a result of deforestation and agricultural practices, but the net carbon emissions (*C*) increased, mainly as a result of the increase in economic growth (GDP) at a faster rate than the decrease in emission intensity as a result of population and productivity increases. For example, in North America the emission intensity decreased at ~1%/year since the middle of the 19th century, but the GDP increased at ~3%/year, resulting in a net increase in CO_2 emissions.

Short of revolutionary, large-scale new technological advances and major expenditures, the energy intensity of the economy will continue to decrease at a lower rate than the rate of GDP increase, and mitigation strategies will have a limited impact (Turkenburg, 1997). Similarly, fossil fuels, which currently provide more than 80% of the world's energy, will likely remain a major component of the world's energy supply for at least this century (Bajura, 2001) because of their inherent advantages, such as availability, competitive cost, ease of transport and storage, and large resources. Other forms of energy production are either insufficient or not acceptable to the public. All studies show that renewable energy forms, such as solar, wind, geothermal, tidal, and hydroelectric, are insufficient to satisfy the global energy needs. In addition, they may face local opposition (e.g., opposition to windmill farms or to large areas being covered by solar panels). Nuclear energy is the only source of energy with significant capacity and potential, but it is politically unacceptable and meets strong public opposition. Thus the carbon intensity of the energy system is not likely to decrease in any significant way in the medium term. This leaves the increase of carbon sinks, S_C, and their capture rate in a significant way as the single major means of reducing net carbon emissions into the atmosphere in the short to medium term, although it is recognized that no single category of mitigation measures is sufficient (Turkenburg, 1997). Even for the long term, on the basis of scarcity of other forms of energy and abundance of fossil fuels, particularly coal, the current thinking is that later in this century the world energy system will be based on hydrogen that will be produced from fossil fuels, with CO_2 as a by-product of hydrogen production. The viability of a hydrogen economy is based on increasing the capacity and sequestration rate of CO_2 sinks.

Large natural CO_2 sinks are terrestrial ecosystems (soils and vegetation) and oceans, with retention times on the order of tens to thousands of years, respectively. Terrestrial ecosystems and the ocean surface represent a diffuse natural carbon sink that captures CO_2 from the atmosphere after release from various sources. The capacity, but not the capture rate, of terrestrial ecosystems can be increased by changing forestry and agricultural practices. However, population increase and other land uses compete with expanding these natural CO_2 sinks. On the other hand, CO_2 capture and sequestration (CCS) presents the possibility of enhancing both the capacity and the capture rate of two major CO_2 sinks: oceans and geological media. CCS is the *removal of CO_2 directly from anthropogenic sources prior to its potential release into the atmosphere (capture) and its disposal deep in the oceans or in geological media, either permanently (sequestration) or for significant time periods (storage).*

The natural, diffuse, and slow exchange of CO_2 between the atmosphere and oceans can be artificially enhanced at concentrated points by injecting/dropping CO_2 at great depths. Depending on depth, hence on pressure, CO_2 may dissolve and diffuse in ocean water or may form either hydrates or heavier-than-water plumes that will sink to the bottom of the ocean (Aya et al., 1999). Currently, the technology for sequestering CO_2 in oceans has not yet been demonstrated at even the experimental and pilot scales. Ocean storage of CO_2 involves issues of poorly understood physical and chemical processes, sequestration efficiency, cost, technical feasibility, and environmental impact, while the technology of disposing of CO_2 from either ships or deep pipelines is only in the development stage. In addition, ocean circulation and processes may bring to the forefront legal, political, and international limitations to large-scale ocean disposal of CO_2. Already, existing marine treaties may severely

curtail this option, while environmental nongovernmental organizations (ENGOs) are opposing this option and mobilizing to stop it. In contrast, the geological storage and/or sequestration of CO_2 is possible with existing technology and can be implemented within national jurisdictions. *CO_2 capture and geological storage or sequestration (CCGS)* refers to CO_2 injection *deep underground* and the associated processes on various time scales that follow injection. Geological storage and/or sequestration of CO_2 is achieved through a combination of physical and chemical trapping mechanisms (Gunter et al., 2004). Physical trapping occurs when CO_2 is immobilized in the free phase (*static trapping* and *residual-gas trapping*) or is dissolved in subsurface fluids (*solubility trapping*) or, either in free phase or dissolved, migrates in the subsurface with extremely low velocities such that it would take time on a geological scale to reach the surface (*hydrodynamic trapping*; Bachu et al., 1994). Chemical trapping occurs when CO_2 undergoes chemical reactions (*geochemical trapping*) or it is adsorbed onto the rock surface (*adsorption trapping*). These means of CO_2 storage can occur in the following geological media: oil and gas reservoirs deep saline aquifers saturated with brackish water or brine, and coal seams and underground cavities (i.e., salt caverns). In short, CCGS currently represents the best short-to-medium-term mitigation option for significantly enhancing CO_2 sinks, thus reducing net carbon emissions into the atmosphere, and is particularly suited to land-locked regions underlain by large sedimentary basins, such as Alberta and Saskatchewan.

In 1990, Alberta's CO_2 emissions at >170 $MtCO_2$ were the second largest in Canada, below those of Ontario. By 2000, Alberta's emissions stood at 223 $MtCO_2$ (Environment Canada, 2002), surpassing Ontario, and it is expected that by 2010 the level of emissions in Alberta will increase considerably both in absolute terms and in relation to other provinces. This increase is mostly due to energy development (e.g., oil sands), but also to petrochemical, power generation, and manufacturing industries. The province is concerned that forcing industry to meet arbitrary emission reduction targets without consideration of economics will result in a loss of competitiveness. Furthermore, there is concern that the extra risks created by uncertain rules implied by ratification of the Kyoto Protocol would scare billion-dollar investments out of the province and into the United States, Venezuela, or the Middle East. Thus Alberta's position is that, while committed to taking effective action on climate change, the steps taken should balance economic risks and the realities of Alberta. However, more recently, Alberta has indicated a readiness to see if the federal government is prepared to work in a true partnership on climate change. One key area of such a partnership would be a joint provincial–federal commitment to accelerate support for CCGS development. Similarly to the United States, Alberta's *Taking Action* approach to climate change is based on reducing emission intensity rather than focusing on an absolute emission reduction target. Alberta's commitment is that, by 2020, the emission intensity relative to GDP will be reduced by 50% from 1990 levels, which is equivalent to a reduction of 60 $MtCO_2$, with a milestone target of 20 $MtCO_2$ by 2010 (compare these targets with annual emissions of 223 $MtCO_2$ in 2000). In regard to CO_2 capture and geological storage, practically only the Alberta and Williston Basins (the Saskatchewan part) have, on a national scale, significant potential for CO_2 geological storage, and serendipitously, that's where major stationary CO_2 sources, such as thermal power plants, refineries, oil sands, and petrochemical plants, are located (Hitchon et al., 1999; Bachu and Stewart, 2002; Bachu, 2003). Alberta has recognized early on CCGS as offering opportunities and has encouraged the development of a

CO$_2$–enhanced oil recovery (EOR) industry in Alberta by instituting a CAN$15 million Royalty Credit Program for companies that initiate these operations. The province also sees CCGS as an integral component of delivering its longer-term 2020 target.

Alberta has multiple options for CO$_2$ geological sequestration (Bachu and Stewart, 2002): in oil and gas reservoirs, including EOR operations, in coal beds, in deep saline aquifers, and in salt caverns. Of these, CO$_2$ sequestration in EOR operations and in coal beds presents the added benefit of producing additional energy resources (oil or methane), thus they represent an attractive target for the initiation of large-scale CO$_2$ sequestration. The CO$_2$ sequestration capacity in oil and gas reservoirs in western Canada, including Alberta, has been studied recently (e.g., Bachu and Shaw, 2004), and the largest oil and gas reservoirs, with individual CO$_2$ sequestration capacity greater than 1 MtCO$_2$, have been identified. They are generally distributed in Alberta in a broad band parallel to the Rocky Mountains. There is no similar study of the CO$_2$ sequestration capacity in coal beds. This report presents the evaluation of CO$_2$ sequestration capacity in Cretaceous–Tertiary coals in Alberta, with the aim of estimating their CO$_2$ sequestration capacity and identifying the areas with large storage potential, particularly in the vicinity of large oil and gas reservoirs, that would constitute prime potential targets for CO$_2$ sequestration in coal beds in Alberta.

CO$_2$ SEQUESTRATION IN COAL BEDS

At atmospheric conditions, CO$_2$ is a gas heavier than air. The triple point for CO$_2$ is at $-56.6°C$ and 0.51 MPa (equivalent to 51 m water column), and the critical point is at 31.1°C and 7.38 MPa (equivalent to 738 m water column) (Figure 1). This means that, depending on pressure, CO$_2$ injected in geological media will be a gas, a liquid, or supercritical because temperatures in the ground will always be greater than $-2°C$, which is the temperature below permafrost in Arctic regions. For temperatures lower than 31.1°C, as pressure increases, CO$_2$ remains a gas until it reaches the vaporization point on the liquid–vapor line (Figure 1). For pressures beyond that point, beyond that point, CO$_2$ is a liquid. For temperatures greater than 31.1°C, there is no sharp boundary between the gaseous and liquid phases. In supercritical state, CO$_2$ has properties of both gases and liquids.

Process of CO$_2$ Sequestration in Coal Beds

A particular type of CO$_2$ fixation (sequestration) occurs when CO$_2$ is preferentially adsorbed onto coal or organic-rich shales (*adsorption trapping*). Coal contains a natural system of fractures called cleats, which impart some permeability to the system. Between the cleats, the solid coal does not contain macropores through which fluids can flow, but does contain a very large number of micropores into which gas molecules can diffuse from the cleat. The combined surface area of the micropores, which form adsorption sites for gas molecules, is very high, and the adsorbed molecules can be very tightly packed. Coal can physically adsorb many gases, and has higher affinity for gaseous CO$_2$ than for methane (Figure 2; Chikatamarla and Bustin, 2003), the volumetric ratio between the two, ranging from as low as 1 for mature coals such as anthracite to as high as 10 for younger, less altered coals. In the presence of multiple gases (e.g., CH$_4$, CO$_2$, N$_2$), the amount of each in the adsorbed state would be
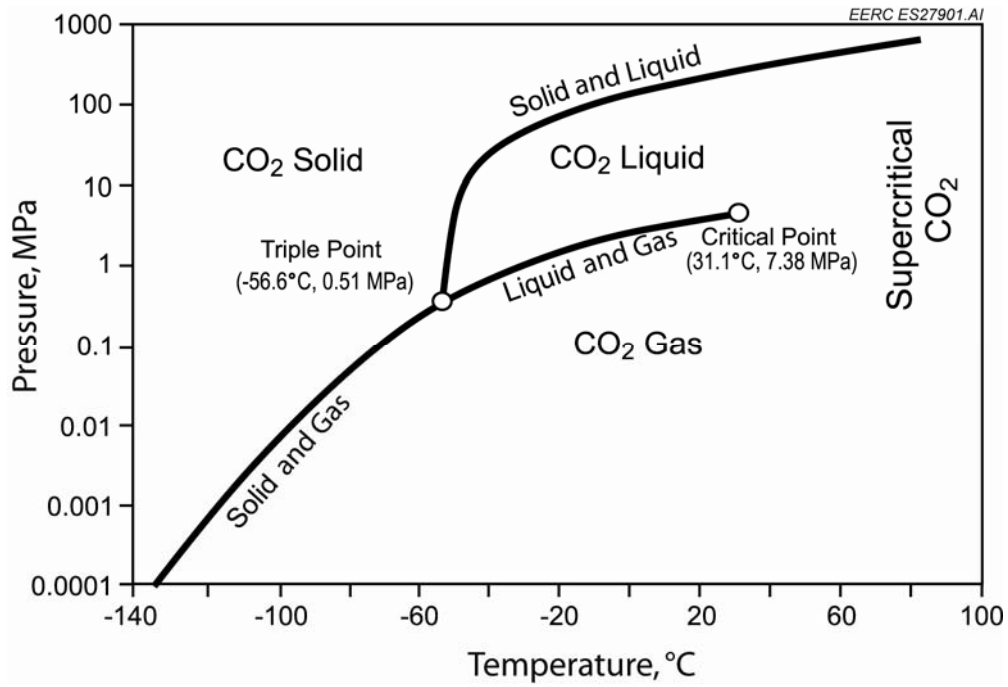
Figure 1. Phase diagram for CO$_2$.
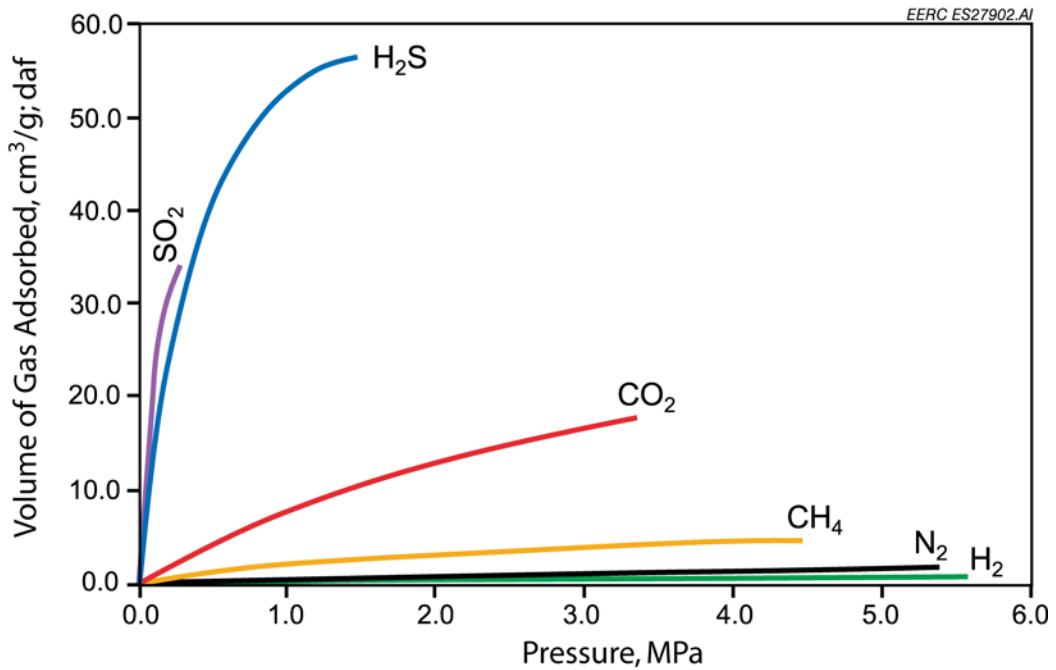
Figure 2. Adsorption of various gases on coal (from Chikatamarla and Bustin, 2003).

approximately in the proportion of their respective affinities (Reeves and Schoeling, 2001).

Coal permeability is a determining factor in the viability of a CO_2 sequestration site. It varies widely and generally decreases with increasing depth as a result of cleat closure with increasing effective stress. Thus, while the permeability of shallow coals (a few hundred meters deep) is on the order of milidarcies (mD) and higher, the permeability of deep coals is on the order of microdarcies (μD). In addition, the effective permeability for gas varies with the extent of water saturation of the coal. Significantly, the economic cutoff for the production of CBM has been estimated as a permeability of 1 mD, and most CBM-producing wells in the world are less than 1000 m deep.

Gaseous CO_2 injected through wells will flow through the cleat system of the coal and will be adsorbed onto the coal surface, freeing up gases with lower affinity to coal (i.e., methane). However, the coal matrix is not a rigid solid but is polymerlike, often affected by the gas or solvent with which it is in contact (White et al., 2005). Coal swells as CO_2 is adsorbed and/or absorbed, which reduces permeability and injectivity (Clarkson and Bustin, 1997; Palmer and Mansoori, 1998; Krooss et al., 2002; Larsen, 2003). Coal swelling generally increases with gas affinity to coal and may reduce permeability by two orders of magnitude or more (Shi and Durucan, 2004). In addition, some studies suggest that the injected CO_2 may react with the coal and/or formation water, which may lead to solids precipitation and further permeability reduction (Reeves and Schoeling, 2001; Zhang et al., 1993). In addition, CO_2 is a "plasticizer" for coal, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure ("coal softening"; Larsen, 2003). The transition temperature may drop from ~400°C at 3 MPa to <30°C at 5.5 MPa (550 m water column equivalent) (Larsen, 2003). Coal plasticization, or softening, destroys any permeability that would allow CO_2 injection. The process of CO_2 trapping in coals for temperatures and pressures above the critical point is much less understood (Larsen, 2003). It seems that adsorption is replaced by absorption and the CO_2 diffuses ("dissolves", Larsen, 2003) in coal. The transition from one process to the other is not sharp, but rather gradual.

At these high-temperature and/or pressure conditions (i.e., for liquid and supercritical CO_2), it is not clear whether CO_2 is adsorbed by coal, occupies the pore space like a fluid with very low viscosity, or infuses into the coal matrix (Ryan and Richardson, 2004). Under these conditions, coals are not a good sequestration medium because CO_2 might be highly mobile and migrate out of the coals into the adjacent strata or within the coals themselves, with the potential for leakage into shallow groundwater aquifers and even to the surface.

The general decrease in coal permeability with depth as a result of increasing effective stress, the coal swelling when CO_2 is injected that further reduces permeability, the lack of understanding of adsorption or absorption processes for liquid and supercritical CO_2, and the potential for coal plasticization in the presence of CO_2 at high pressure and temperature all indicate that, unless significant advances in science and technology are made, only coals at in situ temperature and pressure conditions where CO_2 would remain in the gaseous phase are suitable for CO_2 sequestration. Deeper coals are not suitable for CO_2 sequestration because of lack of

capacity and injectivity and because of current lack of knowledge about the state and fate of the CO_2 in liquid or supercritical state. The change in the trapping process, from adsorption to absorption, and coal plasticization for conditions above the critical point for CO_2, suggest that CO_2 should be injected into coal seams at depths that roughly correspond to temperatures less than about 30°C (Larsen, 2003). These depths are highly dependent on the geothermal regime in a sedimentary basin and can vary from as shallow as 200 m to as deep as 1200–1500 m (Bachu, 2003). However, CO_2 was injected successfully in the San Juan Basin in the United States at a 980-m depth and at a 1260-m depth in Alberta (Gunter et al., 2005), at depths greater than that corresponding to the CO_2 critical point. At the other end, shallow coals are not suitable for CO_2 sequestration because they may be mined in the future in open pits or they may form shallow groundwater aquifers that are used for agricultural, industrial, and/or domestic purposes. Furthermore, not all coals found in the right depth window (not too shallow, but not too deep either) should be considered for CO_2 sequestration. Thick coal seams, even if considered uneconomical under current economic conditions, could be mined in the future, in which case CO_2 will be released and could pose a safety hazard, notwithstanding its return back to the atmosphere. Thus, generally, only unminable coals in multiple thin seams found at depths of 200–300 m and 700–800 m should be considered for CO_2 sequestration. Unminable coals are too thin, too deep, or too unsafe to mine or may be too high in sulfur or mineral matter or too low in heat value to be economically profitable (Byrer and Guthrie, 1998).

CO_2 sequestration in coal beds occurs by replacing and displacing the methane already adsorbed onto the coal. Because methane is a GHG 21 times more powerful than CO_2 in terms of radiative forcing (Bryant, 1997), the methane has to be captured and utilized (i.e., in enhanced coalbed methane recovery, or ECBMR), otherwise the process is more harmful to the climate because, over the long term, it results in a net increase in GHG effects. Thus CO_2 sequestration in coal beds is envisaged to take place in ECBMR operations whereby CO_2 is injected into the coal seam and methane is produced at producing wells (Gunter et al., 1997).

The technology for CO_2 sequestration in coal beds has not been proven to date, although several CO_2 ECBMR pilot and demonstration operations were or are run in Alberta, Poland, Japan, and China (Figure 3). From 1995 to 2001, Burlington Resources ran a pilot CO_2–ECBMR project at the Allison Field in the San Juan Basin in the United States which has a CBM resource of 242 million m^3 per km^2 (Reeves and Schoeling, 2001). The CO_2 was delivered from the McElmo Dome in Colorado. A total of 6.4 Bcf of natural CO_2 has been injected into the reservoir over 6 years, of which 1.6 Bcf is forecast to be ultimately produced, resulting in a net storage volume of 277,000 tCO_2. CO_2 was injected at a constant surface injection pressure on the order of 10.4 MPa at 950 m depth into the Fruitland Formation that had an original pressure of 11.5 MPa. The Fruitland Formation has a thickness of 13 m and is capped by shales that ensure confinement. The injection of CO_2 has resulted in an increase in methane recovery from an estimated 77% of original gas in place to 95% of original gas in place within the affected area. The recovery of methane was in a proportion of approximately one volume of methane for every three volumes of CO_2 injected. The pilot at the Allison Unit has shown clear evidence of significant coal permeability (and injectivity) reduction with CO_2 injection, up to two orders of magnitude (Wo and Liang, 2005). This reduction compromised incremental methane recovery and project economics.
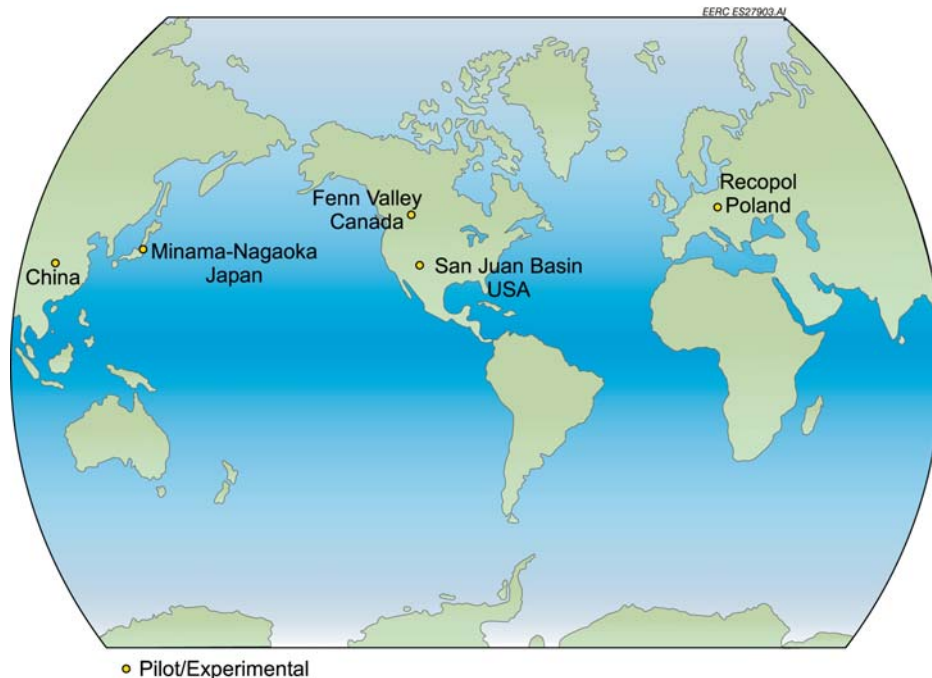
Figure 3. Worldwide location of sites where CO_2 is or was injected into coal beds.

Selection of Sites for CO_2 Sequestration in Coal Beds

Any geological site for CO_2 sequestration, including coal beds, must possess the following characteristics:

1) Capacity for accepting the volumes of CO_2 that need to be stored

2) Injectivity to allow introduction of CO_2 into the subsurface at the desired rates

3) Confining ability to retain the CO_2 for the desired period of time (i.e., avoidance of leakage)

Thus a major issue in CO_2 geological sequestration is the identification and selection of sites suitable for CO_2 injection with retention ability of at least centuries to millennia. The criteria for site selection are based both on site intrinsic (subsurface) characteristics and on extrinsic (surface) considerations that take into account, among other things, economic and societal factors. The following set of screening criteria has been proposed for selecting favorable areas for the successful application of CO_2 ECBMR and CO_2 sequestration in coal beds (Gale and Freund, 2001):

- Adequate permeability: at least 1 to 5 mD.

- Coal geometry: concentrated coal deposits (few, thick seams) are generally favored over stratigraphically dispersed beds comprising multiple, thin seams.

- Simple structure: the reservoir should be minimally faulted and folded.

- Homogeneous and confined reservoir: the coal seam(s) should be laterally continuous and vertically isolated from surrounding strata to prevent migration of excess CO_2 and methane into adjacent aquifers and, possibly, to the surface.

- Gas-saturated conditions: methane-saturated seams should be preferred from a methane production perspective; from a storage perspective, undersaturated coal seams can still be effective.

- Low water saturation: because the coal seam has to be dewatered before it can be used for storage, coals with low water saturation are preferable.

The choice of a CO_2 storage site involves not only application of technical (geological and engineering) and safety criteria, but also a detailed assessment of source quality and quantity, transportation, and integration with economic and environmental factors. If the site is too distant from CO_2 sources or is associated with a high level of technical uncertainty, then its storage potential may never be realized. Thus, in addition to the previous intrinsic criteria, the selection of CO_2 storage sites and matching with CO_2 sources should consider the following extrinsic criteria (Edwards, 2000; Kovscek, 2002):

- Volume, purity, and rate of the CO_2 stream

- Proximity of the source and storage/sequestration sites

- Level of infrastructure for CO_2 capture and delivery

- Existing wells for injection and for leak prevention

- Injection strategies and, in the case of EOR, enhanced gas recovery (EGR) and ECBMR, production strategies

- Presence of energy, mineral, or groundwater resources that might be compromised

- Terrain and right of way

- Proximity to population centers

- Local expertise, overall costs, and economics

Although technical suitability criteria are the primary screening factors for identifying potential CO_2 storage sites, once the best candidates have been selected, any further considerations will be controlled by the economics of each case as well as safety and environmental aspects.

Current Issues in CO_2 Sequestration in Coal Beds

CO_2 capture and geological sequestration have different challenges. The key issue in CO_2 capture is to lower capture costs to economically practicable levels; the processes are known and do not represent high technology risks (International Energy Agency, 2004). On the other hand, significant research and development (R&D) work is still needed to prove the feasibility and integrity of CO_2 storage, particularly in coal beds. Notwithstanding the advanced status of available technology and the experience gained to date in various related and/or similar activities, there are still many issues that need addressing before large-scale implementation of CO_2 capture and geological sequestration occur (Bachu, 2001). These issues fall into the following categories:

a) Scientific and technological
b) Environmental
c) Economic
d) Legal and regulatory
e) Public attitude and acceptance

It is not yet possible to predict with confidence sequestration volumes and integrity and the fate of injected CO_2 over long periods of time. Many important issues must be addressed to ensure safety, reduce costs, and gain full public acceptance. The following is a nonexhaustive identification of issues that require attention in order to advance CO_2 sequestration in coal beds from the conceptual and testing stages to full implementation.

Scientific Issues

Scientific and technological issues that need further research are:

1. The processes of gas adsorption and desorption and ranges of applicability for CO_2 sequestration in coal beds.

2. Prediction of the long-term fate of the injected CO_2, mainly through improved simulation models for coupled processes: mass transport (adsorption and desorption) – fluid flow (water and gas) in the coal cleat system – geomechanical.

3. Determination in a consistent and systematic manner of CO_2 sequestration capacity, both by type and geographically.

Coal swelling and plasticization in the presence of CO_2 need to be better understood, as well as the effects of variability in coal properties on CO_2 sequestration capacity. Currently, there are no models that treat all physicochemical processes associated with CO_2 sequestration in a fully coupled way to simulate the flow of CO_2, methane, and/or water in coal beds. Adequate numerical models need developing and monitoring programs put in place to predict and determine the long-term fate of the injected CO_2 outside the immediate vicinity of the injection well (and for the detection of potential leakage).

A concerted, well-coordinated effort should be directed toward the systematic identification (inventory) of specific sites for CO_2 sequestration in coal beds and their evaluation in terms of capacity. The coal beds require full characterization in terms of depth, pressure, temperature, geometry, structure, rank, ash and gas content, moisture, permeability, and heterogeneity. The sealing unit requires characterization in terms of whether the coal is never mined or depressurized, it is likely that the CO_2 would be sequestered for geological time scales. However, if the coal were disturbed through mining or any other process, this would avoid any potential for CO_2 storage. Thus the likely future fate of a coal seam is a key determinant of its suitability for CO_2 sequestration and in site selection.

Environmental Issues

All the available knowledge and information to date indicate that geological sequestration of CO_2 can be implemented with no greater risks for the local environment and life than similar operations in the energy industry if carried out at suitable and carefully selected sites. However, there is no knowledge and quantification for the long term regarding the probability of CO_2 leakage and the risk associated with it, particularly in regard to faults and wells. The degradation of well cement and casing over very long periods of time, particularly in the presence of CO_2, is not known. Leakage of CO_2 from a sequestration site may contaminate shallow groundwater used for agriculture, industrial, and human consumption. Thus the risk of leakage, particularly through wells and fractures, must be assessed using various methods, including probabilistic ones. A specific environmental issue associated with CO_2 ECBMR is the disposal of produced water, which generally would have to be injected deep into other formations.

Economic Issues

The cost of CO_2 sequestration will affect the decision and viability of implementation. The major capital costs for CO_2 geological sequestration are drilling wells, infrastructure, and project management. Well costs are a major factor in CO_2 ECBMR because many wells are required. For some sites, there may be in-field pipelines to distribute and deliver CO_2 from centralized facilities to wells within the site. For CO_2 EOR, EGR, and ECBMR options, additional facilities may be required to handle the produced oil and gas and separation of CO_2 from the production stream. Reuse of infrastructure and wells may reduce costs at some sites. Operating costs include personnel, maintenance, and fuel. Monitoring adds further costs. However, the value of the additional gas produced would partially offset the cost of CO_2 sequestration, which makes this option attractive.

Regulatory Issues

National and provincial regulations for CO_2 capture and geological sequestration will need to reflect internationally accepted standards for managing sequestration. In a recent report, the CO_2 Task Force set by the Interstate Oil and Gas Compact Commission (IOGCC), which comprises 37 oil- and gas-producing U.S. states and four affiliate Canadian provinces (British Columbia, Alberta, Nova Scotia, Newfoundland, and Labrador), has found that current regulations for the capture, transportation, and injection of CO_2 are reasonably adequate, and that they need only minor adaptation. If

CO_2 is injected in an EOR, EGR, or ECBMR operation, then the active operation is usually covered by corresponding oil and gas conservation acts. The task force has concluded, however, that currently there are no regulations covering the postinjection phase of CO_2 geological sequestration and that these regulations need developing to cover the long-term monitoring, reporting, and remediation aspects of these operations.

Legal Issues

There are several legal issues that need addressing before CO_2 geological sequestration can be implemented on a large scale, and they are ownership of the coal and CO_2 in the subsurface and long- term liability. The way in which liability is addressed may have a significant impact on costs and on public perception of CO_2 geological storage. It is not clear at this time what entity retains liability for the CO_2 injected into geological media at a particular site: the owner of the surface facilities that are the source of CO_2; the operator (third party) that collects the CO_2, transports it, and injects it; or the owner of the pore space. Resolution of this issue is linked to the issue of credits for CO_2 sequestration; most likely the credit holder will be the entity holding the liability, in which case liability may change hands as credits are traded. The long-term in situ risk liability may and most likely will ultimately become a public liability. The cost of monitoring and verification regimes and risk of leakage will play an important role in determining liability, and vice versa.

Public Attitude and Acceptance

Gaining public confidence and acceptance is critical for the large-scale implementation of geological sequestration of CO_2. To achieve this, the public must be credibly convinced that CO_2 geological sequestration is needed and that it is a safe operation, with no risks for environment, property, and life. Many existing surveys have indicated fairly widespread concern over the problem of global climate change and a prevailing feeling that the negative impacts outweigh any positive effects. However, concern about climate change does not imply support for CO_2 capture and geological sequestration. The technology may still be rejected by some as treating the symptoms not the cause, delaying the point at which the decision to move away from the use of fossil fuels is taken, diverting attention from the development of renewable energy options, and holding potential long-term risks that are too difficult to assess with certainty. Acceptance of CO_2 capture and storage, where it occurs, is frequently "reluctant" rather than "enthusiastic" and, in some cases, reflects the perception that CO_2 capture and storage might be required because of the failure to reduce CO_2 emissions in other ways. Furthermore, several studies indicate that acceptance "in principle" of the technology can be very different from acceptance of storage at a specific site (the "NIMBY" syndrome). By analogy, proposals for underground natural gas storage schemes have generated public opposition in some localities, because of concerns regarding the effects of underground natural gas storage upon local property prices and difficult-to-assess risks.

The above review of the process of CO_2 sequestration in coal beds and associated ECBMR; the identification, characterization, and selection of potential sites for CO_2 sequestration; and the current scientific and technical, economic, regulatory, legal, and public opinion issues associated with CO_2 sequestration in coal beds indicates

that, for Alberta, as for any other jurisdiction, the selection of sites for CO_2 sequestration in coal beds and estimation of their capacity needs to consider all of these factors.

COAL AND CBM IN ALBERTA

The term "coalbed methane'" is typically applied to gases contained in coal beds, because methane is the dominant gas. However, significant amounts of CO_2 and longer-chain hydrocarbon gases, such as ethane and propane, are also commonly found in coalbed gases, and for this reason, in British Columbia it is called "coalbed gas." CBM resources worldwide may be as high as 8870 Tcf (250×10^{12} m^3), several times greater than the collective reserves of all known conventional gas fields (Gayer and Harris, 1996). However, CBM has not been generally exploited because of the abundance of, and better economic conditions for, other fossil energy resources. Although coal has been extracted for a long time in many sedimentary basins, CBM was seen primarily as a danger in underground mining, and only recently has CBM been recognized as a valuable energy resource that can be economically exploited.

Gas is stored within the coal as 1) limited free gas within the micropores and cleats (fractures) of the coal; 2) dissolved gas in the water within the coal; 3) adsorbed gas held by molecular attraction on the surfaces of coal particles, micropores, and cleats; and 4) absorbed gas within the molecular structure of the coal (Yee et al., 1993). The ability of any particular coal to store gases is a function of several factors, including coal rank and quality, burial depth (because increasing pressure and temperature allow for increased storage), and water saturation. Thus, unlike conventional hydrocarbon plays, coal in CBM plays acts as both the source rock and the reservoir for the gas.

Gas migration within coal takes place by a combination of desorption, diffusion, and free-phase flow and occurs as a direct result of decrease in pressure. Thus gas recovery is achieved by decreasing the pressure through dewatering. Continuous water production from a coal bed results in a corresponding progressive increase in gas production up to a certain limit, which depends on coal thickness, depth (original pressure and temperature), absolute and relative permeability, compressibility, and gas saturation (Montgomery, 1999). However, the same dewatering that leads to methane production may place limits on actual development because of environmental issues and high costs associated with water disposal (Montgomery, 1999; Johnson and Flores, 1998).

Production rates of CBM are extremely sensitive to reservoir properties, of which permeability is critical (Zuber et al., 1996). Low permeability is one of the leading causes for the lack of development of CBM in Rocky Mountain basins (Johnson and Flores, 1998; Montgomery, 1999). Regardless of the quantity of gas in place, there is a permeability value below which the resource cannot be produced economically, estimated to be 10^{-15} m^2 (1 mD; Zuber et al., 1996). Data from the Piceance, San Juan, and Black Warrior Basins in the United States and from the Sydney and Bowen Basins in Australia document a decrease in permeability with burial depth. Thus low permeability is likely to be a problem with deep coal seams, in that coalbed reservoirs

deeper than 1500 m generally have permeabilities below what is presently required for economical CBM production (Zuber et al., 1996) and CO_2 sequestration.

CBM in Rocky Mountain Sedimentary Basins

As a result of special tax credits, the development of unconventional gas resources in the United States has grown considerably since the late 1980s, so that currently CBM accounts for close to 11% of their natural gas production. The principal producing areas in the United States are the mature San Juan Basin in Colorado and New Mexico and the Black Warrior Basin in Alabama. The Powder River Basin in Wyoming and Montana has recently emerged as a CBM producer, and other basins with future potential are the Greater Green River Basin in Wyoming and the Piceance Basin in Colorado. Production occurs at depths varying from as shallow as 45 m in thick Paleocene coal beds of the Powder River Basin to approximately 2000 m in Upper Cretaceous coal beds of the Piceance Basin (Montgomery, 1999). All CBM-producing basins in the United States, except for the Black Warrior, are Rocky Mountain basins. Also, within the contiguous United States, as much as 79% of CBM resources, estimated at 675 Tcf, are found in late Cretaceous and early Tertiary coal in undeformed foreland basins of the Rocky Mountain region (Murray, 1996; Montgomery, 1999). Although the Alberta Basin is also a foreland Rocky Mountain basin that contains extensive late Cretaceous and early Tertiary coal beds, its CBM potential has not been truly evaluated, and exploration and production are only in an incipient stage, driven mainly by the recent increase in the price of natural gas and declining gas reserves. Because of limited exploration and production, estimates of CBM potential for Alberta vary widely between 187 Tcf (McLeod et al., 2000) and 540 Tcf (Canadian Gas Potential Committee, 1997).

Coalification is the process by which peat is transformed into coal during progressive burial, a process that involves the expulsion of volatiles (mainly methane), water, and CO_2. Coal in the Rocky Mountain foreland basins was deposited during three different time periods: 1) late Jurassic–early Cretaceous, 2) late Cretaceous, and 3) Paleocene and Eocene. The most extensive Cretaceous coal beds were deposited in coastal plain settings along the margins of the Western Interior epicontinental seaway that covered much of the foreland basin east of the Rocky Mountain overthrust belt. The large foreland basin that extended from the Arctic Ocean to the Gulf of Mexico during the Cretaceous has been partitioned by the Tertiary Laramide orogeny into the very large Alberta Basin in Canada and much smaller basins in the United States, such as the Powder River, Wind River, Hanna, Greater Green River, Piceance, Uinta, San Juan, and Raton Basins (Johnson and Flores, 1998). Coalification in the American Rocky Mountain basins occurred as a result of 1) burial by foreland basin sediments during the Cretaceous, 2) burial by Laramide basin sediments from late Cretaceous through Eocene and subsequent burial beneath Oligocene and younger sedimentary and volcanic rocks, and 3) increased geothermal gradients related to Oligocene and younger igneous events (Johnson and Flores, 1998). In the Alberta Basin, the first two factors are the most likely causes of coalification, because igneous events are minor and isolated. Estimates of the amount of overburden removed by tertiary to recent erosion range from 1000 m to approximately 4000 m (Nurkowski, 1984; Kalkreuth and McMechan, 1988; Bustin, 1991). This indicates that the initial peat accumulations have been subjected to high temperatures and pressures,

sufficient for coalification and gas generation, a process that seems to be still active today.

Gases can be generated from coal beds during three stages:

- Early biogenic gas is formed during an early shallow burial phase dominated by microbial degeneration of original organic material in the early stages of coalification and coupled with physical compaction, maceration, and water expulsion.

- Thermogenic gas is formed by thermal processes during the main stages of abiogenic coalification.

- Late-stage biogenic gas is generated by bacterial activity associated with groundwater systems, regardless of the coal's rank.

The most commonly encountered coalbed gases in Rocky Mountain basins are of the second and third types and mixes of these two (Johnson and Flores, 1998). Low-rank coal deposits that exist at shallow depths and have significant outcrop exposure may contain mainly late-stage biogenic methane, which seems to be the case with the CBM-producing Fruitland Formation in the San Juan Basin and the Fort Union Formation in the Powder River Basin (Scott et al., 1994; Montgomery, 1999) and, possibly, in the Alberta Basin in areas of shallow groundwater circulation (Bachu and Michael, 2003).

Coals and CBM in the Alberta Basin

The Alberta Basin, initiated during the late Proterozoic by rifting of the North American craton, lies on a stable Precambrian platform and is bounded by the Intramontane and Omineca orogenic belts to the west and southwest, the Tathlina High to the north, the Canadian Precambrian Shield to the northeast, and the Williston Basin to the east and southeast. The undeformed part of the basin comprises a first-order wedge of sedimentary rocks that increases in thickness from zero at the edge of the Canadian Shield in the northeast to more than 6000 m at the edge of the thrust and fold belt in the southwest. The basin has a gently dipping east flank against the Precambrian basement and a steeply upturned and highly faulted west flank against the frontal thrust of the Rocky Mountain overthrust belt.

The basin consists of a passive margin succession, dominated by carbonate and evaporite deposition with some intervening shale, followed by a foreland basin succession dominated by clastic, largely shale deposition since the middle Jurassic. Pre-Cretaceous erosion has partially removed older strata, which subcrop at the unconformity from southwest to northeast, with increasing age, from Jurassic to middle Devonian. Continued uplift associated with the Columbian orogeny in the early Cretaceous provided abundant sediment to the foredeep trough, resulting in fluvial deposition, including peat, in the southern and central parts of the basin and coeval marine shale deposition in the northern part of the Mannville Group. The Colorado Group succession of thick marine shale and several thin, isolated, intervening

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sandstone sheets was deposited during the following lull in plate convergence and major sea-level rise in the early late Cretaceous.

The lull in tectonic activity ended with the deposition of the thick and competent marine shale of the Lea Park Formation and its equivalent in southern Alberta, the Pakowki Formation. The first major influx of Cordilleran clastic detritus of fluvial origin created the thick, coal-bearing Belly River Group. Another major rise in relative sea level resulted in the shale deposition of the Bearpaw Formation in the southern part of the basin. During the late Cretaceous to early Tertiary, two other major, coal-bearing, coarse clastic successions, the Horseshoe Canyon and Scollard Formations, were deposited in the southern part of the basin. They were similarly derived from the Cordillera and are separated by the marine shale of the Battle Formation. In the west-central part of the basin, where the Bearpaw Formation is absent because of nondeposition, the coarse clastic deposits of the Belly River Group and Horseshoe Canyon Formation are undistinguishable from each other and form the Wapiti Group. Similarly, the Bearpaw Formation is absent close to and along the thrust and fold belt, where the Belly River Group and Horseshoe Canyon Formation coalesce into the Brazeau Group.

Coarse clastic deposition continued in the early Tertiary with deposition of the Paskapoo Formation. Subsequent to this cycle, a period of tectonic compression and uplift followed in the early Tertiary (the Laramide orogeny), leading to the deposition of fluvial channel sandstone, siltstone, and shale. Between 1600 and 3800 m of sediments were deposited in the southern part of the Alberta Basin and subsequently removed by erosion since the Paleocene (Nurkowski, 1984; Bustin, 1991). As a result, the Lea Park–Paskapoo succession is exposed at the top of the bedrock under unconsolidated Quaternary sediments of preglacial and glacial origin, with increasing age from the basin foredeep in the southwest to the basin edge in the northeast (Figure 4).

Peat accumulated in the Alberta Basin during the late Jurassic and early Cretaceous and during the late Cretaceous and early Tertiary, leading to the formation of coal deposits in the Lower Cretaceous Mannville Group, the Upper Cretaceous Belly River Group and Horseshoe Canyon Formation of the Edmonton Group, and the Upper Cretaceous–Paleocene Scollard and Paskapoo Formations. Unlike in some Rocky Mountain basins in the United States, large-scale volcanism and igneous events are absent from the Alberta Basin, and only small-scale pipes and intrusions are present. As a result, coal rank and gas content are the result of burial only. Coal in this succession ranges from lignite to high-volatile bituminous in rank, generally increasing in rank from east to west, consistent with increasing depth (Bustin, 1991). The coal seams dip to the west and occur at depths ranging from surface outcrop to more than 2500 m. The stratigraphic location of various Cretaceous–Tertiary coal zones in Alberta is shown in Figure 5, and their areal extent is shown in Figure 6.

Jurassic and Lower Cretaceous Mannville coals are mined in surface mines in the Rocky Mountain foothills in Alberta and British Columbia where thrusting and folding brought them to the surface. Upper Cretaceous–Tertiary coals are or were mined in Alberta plains in open-pit mines or shallow underground mines along the outcrop of the various coal zones (Figure 7).
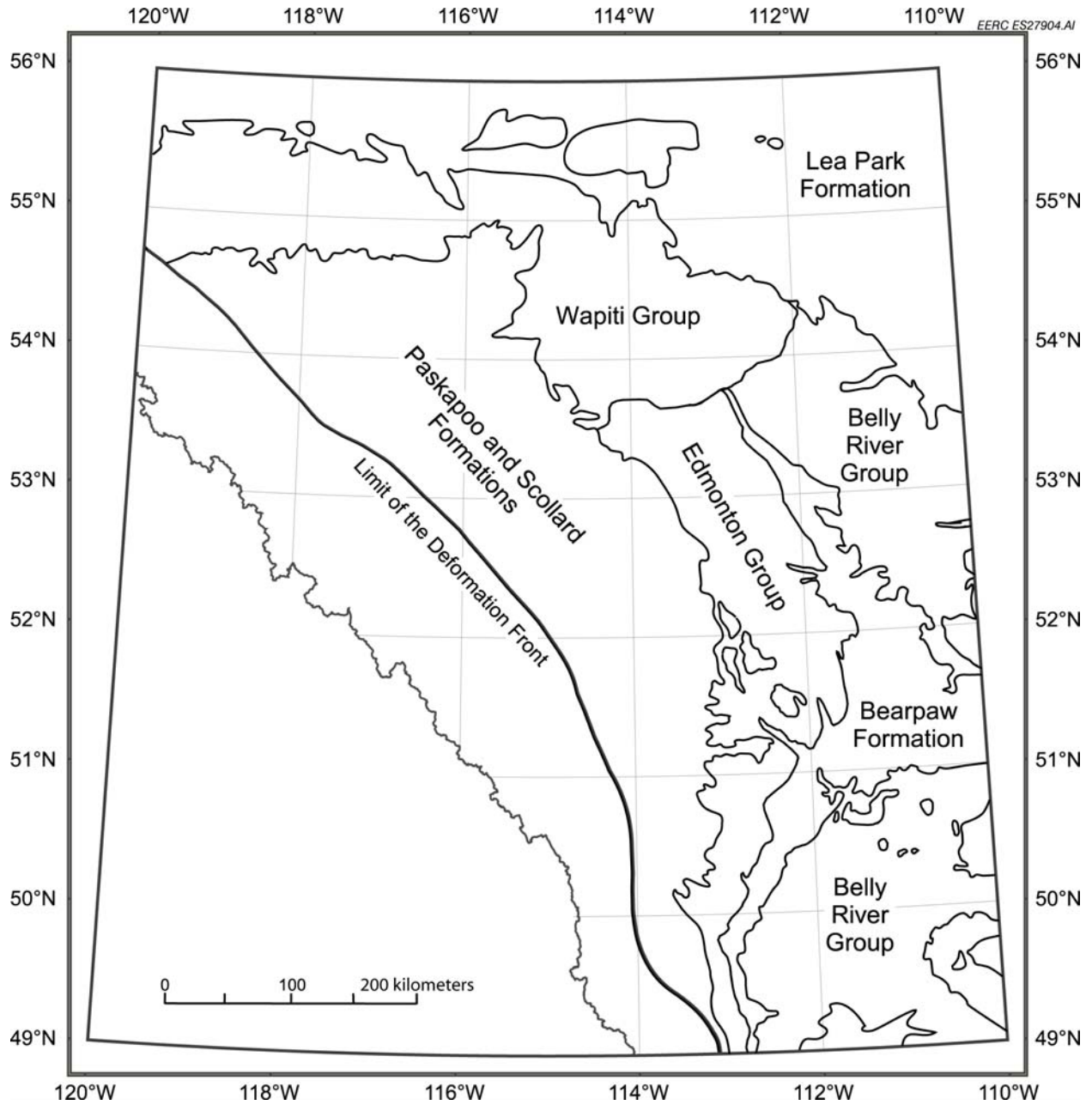
Figure 4. Erosional boundaries and outcrop at the top of the bedrock of Upper Cretaceous–Tertiary coal-bearing strata in Alberta.

STRATIGRAPHY | HYDROSTRATIGRAPHY

EERC ES27905.AI

| | NORTH CENTRAL ALBERTA | SOUTH CENTRAL ALBERTA | SOUTHEASTERN ALBERTA | |

TERTIARY
- PASKAPOO FM | PASKAPOO FM | RAVENSCRAG FM — SCOLLARD-PASKAPOO
- ARDLEY/KAKWA CZ | ARDLEY CZ | FRENCHMAN FM
- SCOLLARD FM | SCOLLARD FM | BATTLE FM — BATTLE
- BATTLE FM | BATTLE FM | WHITEMUD FM
- | WHITEMUD FM
- | CRB-THM CZ | EASTEND FM — EDMONTON - UPPER WAPITI
- CUTBANK CZ | HORSESHOE CANYON FM
- | DRUMHELLER CZ
- RED WILLOW CZ | BEARPAW FM | BEARPAW FM — BEARPAW

UPPER CRETACEOUS
- WAPITI GP / EDMONTON GP
- BELLY RIVER FM
- BELLY RIVER GP: LETHBRIDGE CZ — UPPER BELLY RIVER
- DINOSAUR PARK FM / OLDMAN FM
- TABER CZ — MIDDLE BELLY RIVER
- FOREMOST FM
- MCKAY CZ — BASAL BELLY RIVER
- LEA PARK FM | LEA PARK FM | PAKOWKI FM — LEA PARK
- | | MILK RIVER FM — MILK RIVER

- COLORADO GP | COLORADO GP | COLORADO GP — COLORADO AQUITARD SYSTEM
- CARDIUM FM
- VIKING FM | VIKING FM | BOW ISLAND FM — VIKING
- JOLI FOU FM | JOLI FOU FM — JOLI FOU

LOWER CRETACEOUS
- MANNVILLE GP
- FAHLER CZ | UPPER CZ | UPPER — MANNVILLE AQUIFER SYSTEM
- UPPER | UPPER
- CLEARWATER FM | CLEARWATER FM
- GETHING CZ
- LOWER | LOWER | LOWER

Legend: Sandstone | Shale | Coal Zone | Absent Due to Erosion | Aquifer | Aquitard

Figure 5. Stratigraphic and hydrostratigraphic nomenclature and delineation of the coal-bearing Cretaceous–Tertiary strata in the Alberta Basin and position of coal zones.

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120°W 118°W 116°W 114°W 112°W 110°W EERC ES27906.AI

60°N

59°N

58°N

57°N

56°N

55°N

54°N

Edmonton

53°N

Red
Deer

52°N

Ardley Coal Zone
Cabon–Thompson Coal Zone
Drumheller Coal Zone
Lethbridge Coal Zone
Taber Coal Zone
McKay Coal Zone
Mannville Coal Zone

51°N

Calgary

50°N

0   100   200   300 km

0   100   200 mi

49°N

120°W 118°W 116°W 114°W 112°W 110°W

Figure 6. Areal extent of the Cretaceous–Tertiary coal zones in Alberta.

Figure 7. Coalfields in the Alberta plains.

The CBM potential was estimated for the major coal zones in the Upper Cretaceous–Tertiary succession: McKay, Taber, and Lethbridge in the Belly River Group; Drumheller, Daly–Weaver, and Carbon–Thomson in the Horseshoe Canyon Formation; and Ardley in the Scollard Formation (Beaton et al., 2002). Coal zone area, coal tonnage, and gas in place (GIP) for each coal zone are summarized in Table 1, and the areal distribution of potential GIP is shown for selected coal zones in Figure 8. In each coal zone, the most prospective areas coincide, as expected, with the greatest net coal thickness and elevated gas contents.

The Ardley Coal Zone has, by far, the highest potential for CBM in the Upper Cretaceous–Tertiary succession, with the highest potential in the northwest (Figure8a). The highest gas potential in the Horseshoe Canyon Formation of the Edmonton Group is found in the Drumheller Coal Zone (Table 1). Elevated gas concentrations are present in a north-trending belt in central Alberta, locally reaching maximum concentrations of 4 to 6 Bcf/square mile (44 to 66×106 m^3/km^2), particularly in a large area northe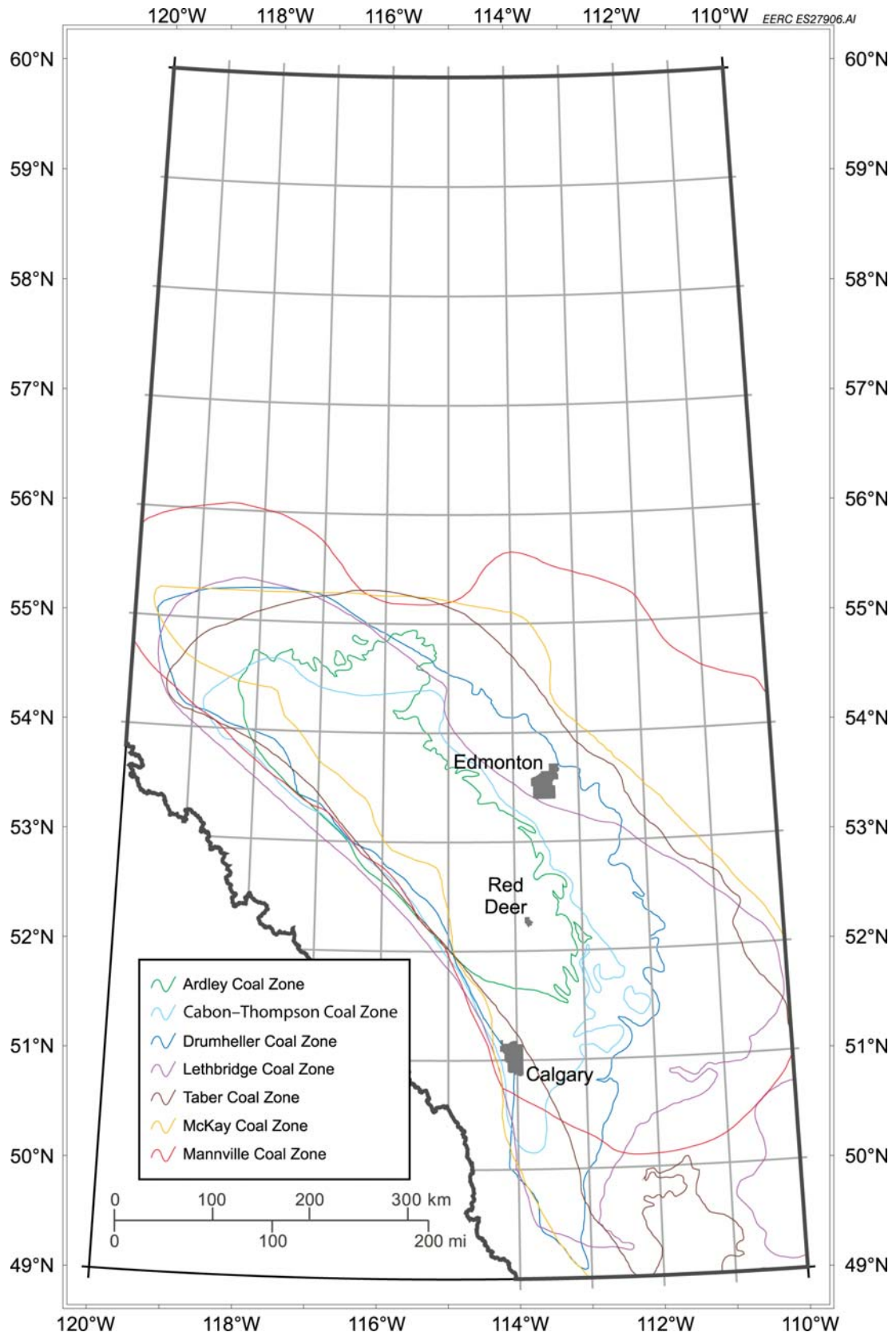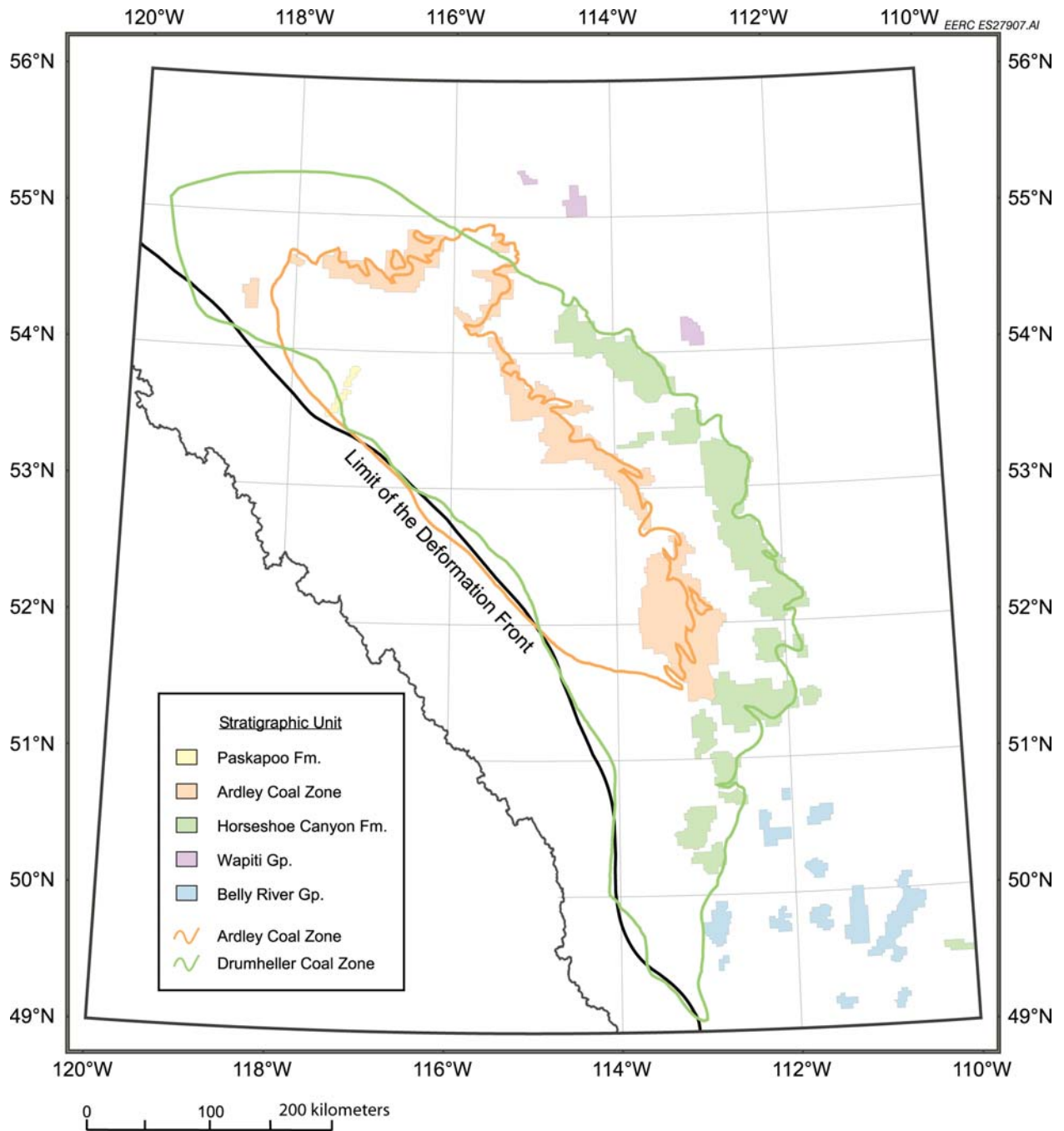ast of Calgary (Figure 8b). The total GIP in the Daly–Weaver and Carbon–Thompson Coal Zones is comparably lower. Gas concentrations are typically less than 1.5 Bcf/square miles (16×106 m^3/km^2) for these two coal zones. The gas potential for the two coal zones at the top of the Belly River Group, the Lethbridge and Taber Coal Zones, is also relatively low (Table 1). Elevated gas concentrations are present in the Lethbridge Coal Zone in local pods in a north-trending band between Edmonton and Calgary (Figure 8c) that coincide with areas of high gas concentration in the overlying Drumheller Coal Zone (Figure 8b). In the Taber Coal Zone, elevated gas concentrations are found in the southeast corner of Alberta. The McKay Coal Zone at the base of the Belly River Group contains the largest amount of coal within the Belly River Group, but still with comparatively reduced potential by comparison with the Ardley and Drumheller Coal Zones (Table 1). Relatively elevated gas concentrations occur in pods along a north-trending band in southern-to-central Alberta (Figure 8d).

The estimated CBM potential of the Mannville coals is by far the largest of all coal zones in Alberta's plains. Originally, it was estimated at 400 Tcf (McLeod et al., 2000), but more recently, it was adjusted down to 320 Tcf (Beaton, 2003). However, this figure encompasses the entire areal extent of the Upper Mannville Coal Zone (Figure 6) down to depths close to 3500 m. If only coals at depths less than 1500 m are considered, on the basis that the permeability of deeper coals is too low to allow production, then the estimates of potential GIP drop to 144 Tcf (A. Beaton, personal communication), which is still greater than that of the other coal zones. However, if only coals at depths less than 800 m are considered, which some authors accept as approximately the lower limit for CO_2 storage in coal beds, then the estimates of gas in place drop further to only 25 Tcf (A. Beaton, personal communication). From the point of view of CBM exploration and production, and of potential CO_2 sequestration, the target window for Upper Mannville coals is relatively limited compared to their large areal extent. At depths attractive for reservoir permeability, the coal is of low rank, with limited cleat development and lower gas content (Dawson et al., 2000). Where rank is sufficiently high to place the coal in the thermogenic gas generation window, the coal is commonly deeper than 1000 m and the reduction in permeability becomes an obstacle. Thus some form of permeability enhancement is required to allow CBM production and, correspondingly, CO_2 injection, as demonstrated by the poor production results from the Fenn–Big Valley Field near Stettler.
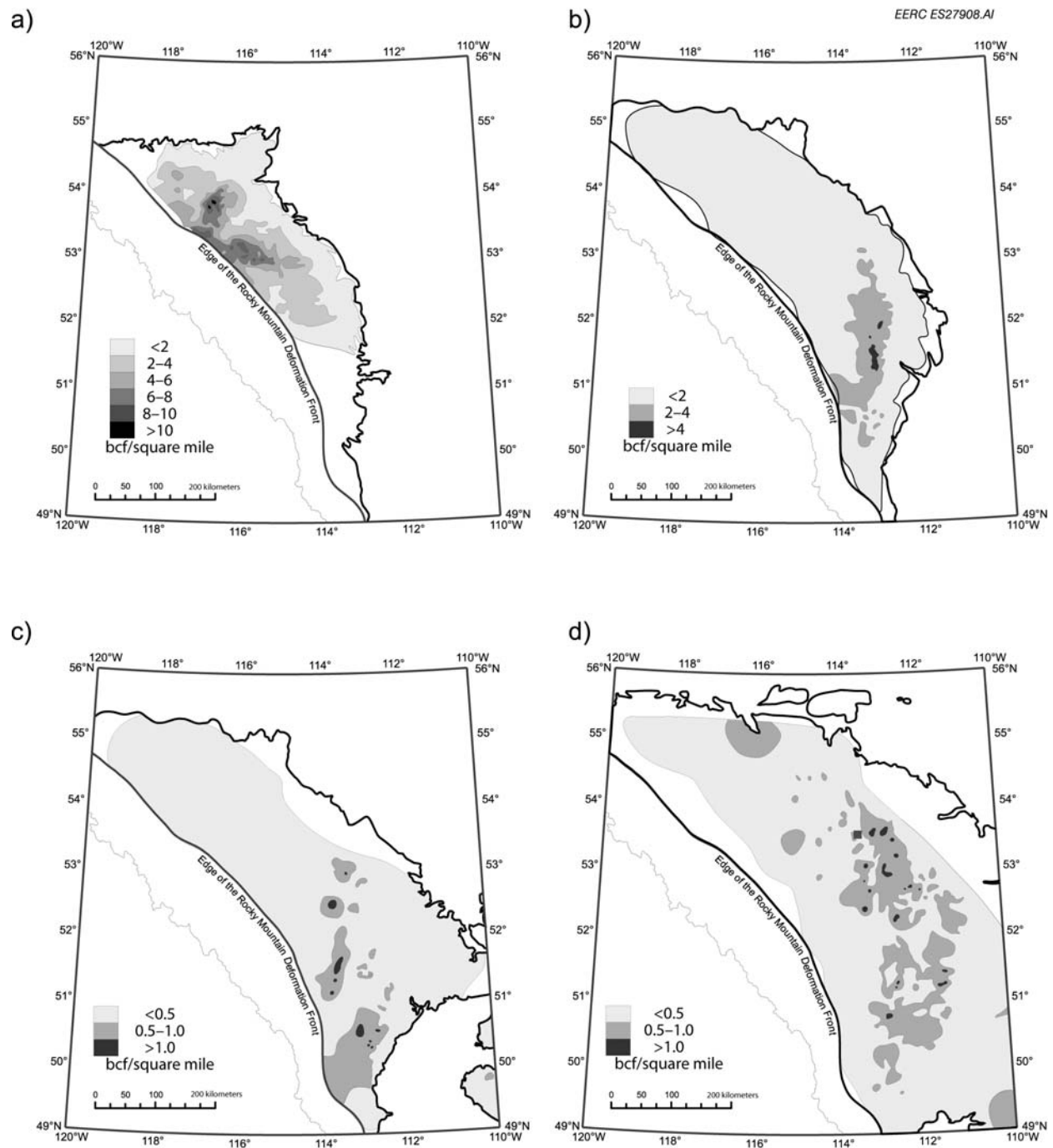
Figure 8. Gas potential (Bcf/m²) of selected Upper Cretaceous–Tertiary Coal Zones in Alberta (after Beaton et al., 2002): a. Ardley; b. Brumheller; c. Lethbridge; and d. McKay.

**Table 1. Summary of Coal and Gas Potential for Upper Cretaceous–
Tertiary Coals in the Alberta Plains (from Beaton et al., 2002). Gt =
gigatonnes, Tcf = trillion cubic feet**

Coal Zone	Unit	Area, 10^3 km²	Coal Tonnage, Gt	GIP, Tcf
Ardley	Scollard	59	596	50.6
Carbon–Thompson	Horseshoe Canyon	76	183	12.8
Daly–Weaver	Horseshoe Canyon	76	178	12.4
Drumheller	Horseshoe Canyon	128	564	33.0
Lethbridge	Belly River	170	277	8.7
Taber	Belly River	190	335	11.0
McKay	Belly River	212	403	18.7

During the past few years, the interest in exploring for and producing methane
from coals in the Alberta plains has increased significantly (Figure 9). To the summer
of 2005, 3421 CBM wells have been drilled in the Drumheller and Lethbridge Coal
Zones, targeting them both because of their stratigraphic proximity, the two being
separated only by the shales of the Bearpaw Formation. The wells (Figure 10) are
concentrated in the area of high CBM potential (Figures 8b and 8c). Two hundred and
sixty-four wells were drilled in the Upper Mannville Coal Zone, 76 wells in the Ardley
Coal Zone, 14 wells in the McKay and Taber Coal Zones of the Belly River Group, and
three wells in the Carbon–Thompson Coal Zone. The well distribution is shown in
Figure 10. Besides these, 41 CBM wells have been drilled in the Mist Mountain coals
in the Rocky Mountain foothills.

Figure 9. Increase in drilling activity for CBM in Alberta.

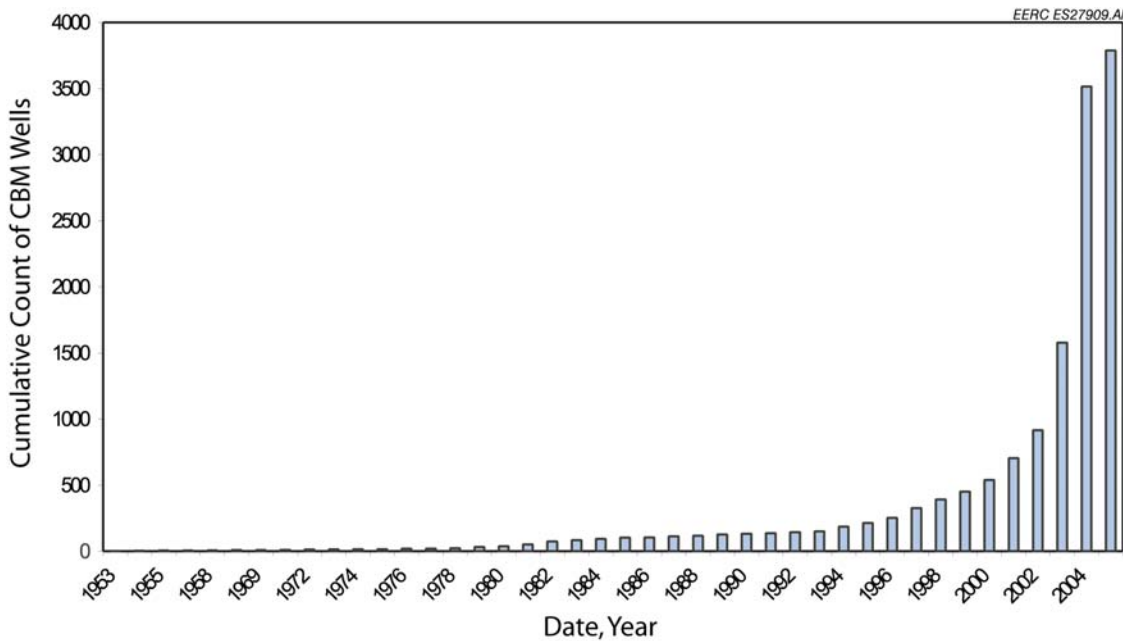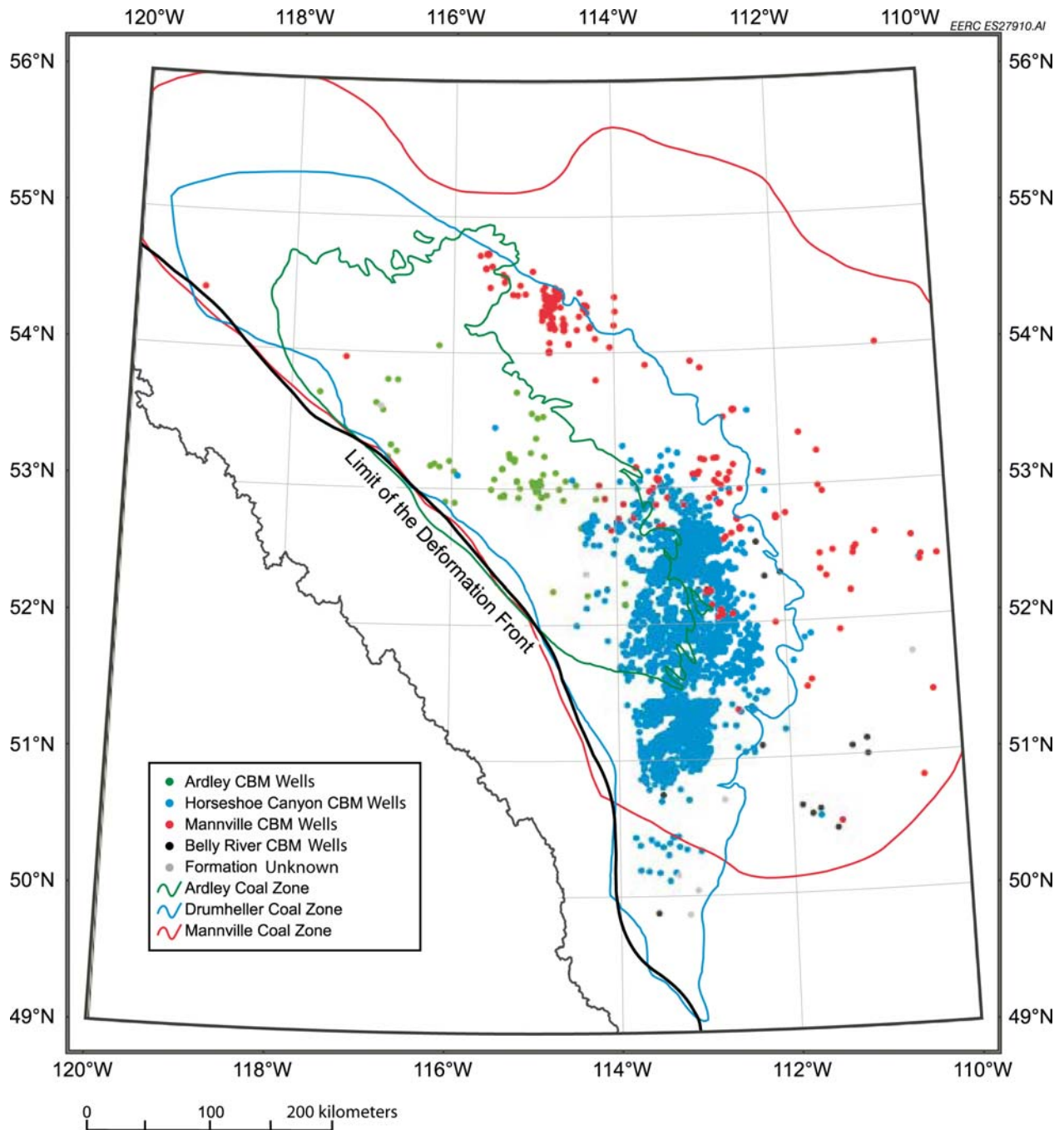Figure 10. Location of CBM wells in the Alberta plains in 2005.

CHARACTERISTICS OF THE MAIN COAL-BEARING STRATA IN ALBERTA

The purpose of this study is to evaluate the CO_2 sequestration potential and capacity in Alberta's coals. Since coal thickness and gas content are indicators for the potential for CO_2 storage, examination of Table 1 suggests that the only Upper Cretaceous–Tertiary coals that may possess significant CO_2 sequestration capacity worthy of consideration are the coals of the Ardley and Drumheller Coal Zones. The larger area of the Carbon–Thomson and Daly–Weaver Coal Zones than that of the Ardley Coal Zone (by ~29%) and their much lower CBM potential (only (~25%) indicate that these coals are thin, discontinuous, and likely to have very limited CO_2 sequestration capacity. Similarly, the significantly larger area of the coal zones in the Belly River Group and their smaller gas potential (Table 1 and Figures 8c and 8d) indicate that these coals are also thin, possibly discontinuous, and possess very limited CO_2 sequestration capacity. Thus the focus of this investigation is estimating the CO_2 sequestration potential and capacity in the Ardley, Drumheller, and Upper Mannville Coal Zones and identification of areas with high potential for CO_2 sequestration.

The Upper Mannville Coal Zone has the largest areal extent (Figure 11), from ~50°N to ~56°N latitude, and from the eastern limit of the Rocky Mountain deformation front in the west to the Alberta– Saskatchewan border in the east (it actually extends into the southern part of northeastern British Columbia in the northwest and into Saskatchewan in the east). The Drumheller Coal Zone covers a wide arcuate band along the Rocky Mountain deformation front and west of112°W longitude, from close to the U.S. border in the south to slightly north of 55°N latitude in the northwest (Figure 11). The Ardley Coal Zone extends in a band ~130 km wide along the Rocky Mountain deformation front from ~51.6°N to close to 55°N latitude (Figure 11). Most of this region in Alberta, south of 56°N latitude, is used for agricultural purposes ("white" zone in Figure 11), with forested areas in the northwest and north ("green" zone in Figure 11). Surface topography, the result of Tertiary to recent erosion, drops gently in the study area from an elevation of more than 1200 m along the thrust and fold belt in the west along the Rocky Mountain Foothills and at the Swan Hills in the north to less than 600 m in the northeast (Figure 12).

Geology, Depositional Environments, and Coal Characteristics

Mannville Group and Upper Mannville Coal Zone

The siliciclastic sediments of the Lower Cretaceous Mannville Group were deposited during the Columbian orogeny on an eroded and incised pre-Cretaceous unconformity surface that truncates strata ranging from Jurassic in the west to lower Paleozoic in the east. The sediments of the Lower Mannville Group in the study area are entirely continental, representing a series of coalescing alluvial fans and river deposits along three major paleodrainage systems, the Spirit River, Edmonton, and Assiniboia, that drained through major delta complexes in the Boreal Sea to the north. The upper Lower Mannville and the lower-to-middle Upper Mannville strata record the transgression and regression of the Clearwater Sea from the north as the basin continued to subside, and they consist primarily of shales, siltstones, and lenticular sandstones.
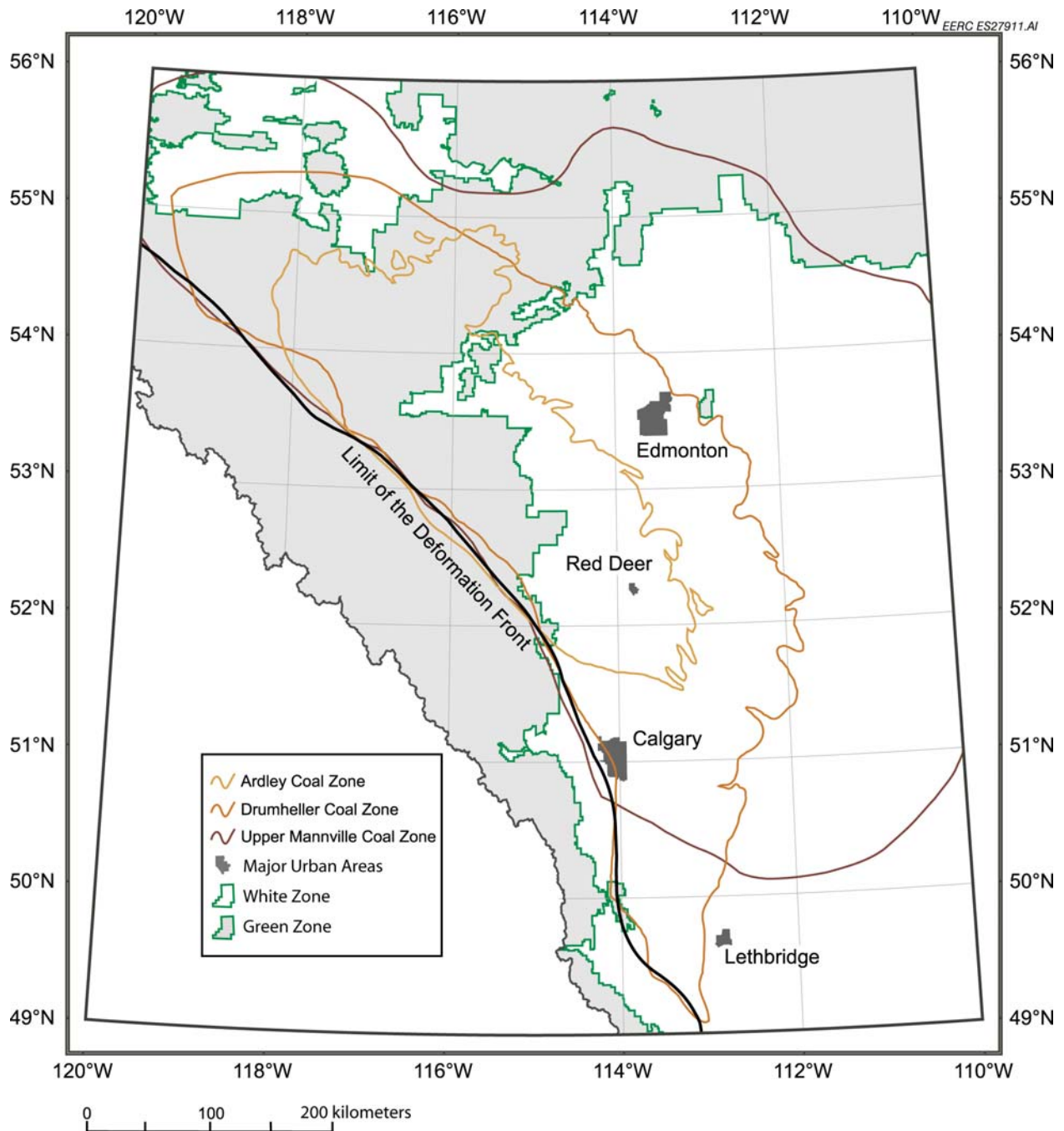
Figure 11. Areal extent of the Upper Mannville, Drumheller, and Ardley Coal Zones in the southern half of Alberta and the extent of the forested areas ("green" zone) and of land used for agriculture ("white" zone).
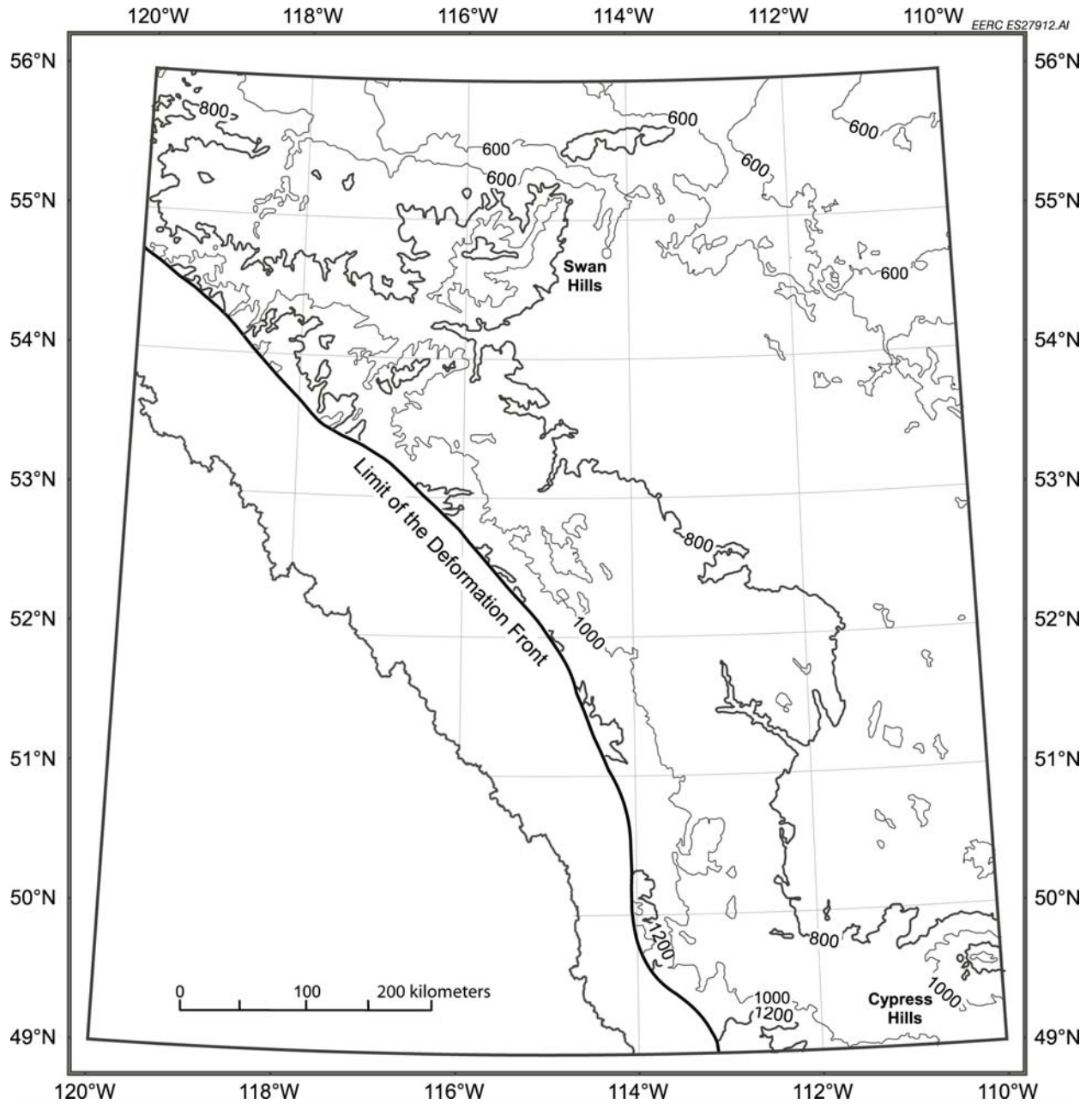
Figure 12. Ground surface topography in the study area. Contour interval = 200 meters.

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A major influx of Cordilleran-derived sediment followed during middle and Upper Mannville time in southern and central Alberta, pushing the shoreline northward and transforming the region into a floodplain. Fluvial conditions prevailed, with deposition of channel sandstones, siltstones, shales, and coals. Following this depositional cycle, a major sea-level lowstand resulted in exposure and partial erosion of the Upper Mannville strata (post-Mannville unconformity). A subsequent major sea-level rise flooded the Alberta Basin, such that the preserved strata of the Upper Mannville Group are overlain by the tight shales of the Joli Fou Formation everywhere except for a narrow floodplain along the Cordillera. Continuing rise of the global sea level, coincident with a regional tectonic down-flexing of the North American craton led to deposition of thick marine shale sediments of the Colorado Group, separated intermittently by regressive pulses represented by the sandstones of the Viking and Cardium Formations.

Depth to the top of the Upper Mannville Coal Zone varies from less than ~475 m in the northeast to 3590 m in the southwest at the Rocky Mountain deformation front (Figure 13). Coal seams, varying in number from 1 to 15, have a cumulative thickness that ranges from 0.2 m to 16.5 m, with the thickest coals found in west-central Alberta (Figure 14). The total thickness of the Upper Mannville Coal Zone, comprising the coal seams and intervening layers, varies between 0.2 m and 72.2 m. Coal rank reflects the depth of burial and ranges from lignitic and subbituminous C in the northeast (reflectance 0.3%–0.4%) to low-volatile bituminous in the west at its deepest (reflectance >1.5%), but most of the Upper Mannville coals are subbituminous to high-volatile bituminous. Mannville coals can be seen in outcrop and/or in open mines only in the Rocky Mountain Foothills, where folding and thrusting have brought them to the surface (Figure 15).

Horseshoe Canyon Formation and Drumheller Coal Zone

The uppermost Cretaceous–Tertiary sediments in the Alberta Basin form an eastward-thinning prism that was deposited during the Laramide orogeny and subsequent (Tertiary) tectonic relaxation. As a result, predominantly nonmarine sediments in the west intertongue with marine strata in the east. The stratigraphic interval can be divided into four periods of extensive sandy deposition, represented by the Belly River, Horseshoe Canyon, lower Scollard and Paskapoo wedges, and four intervals of fine-grained deposition, represented by the intervening shales of the Lea Park, Bearpaw, and Battle Formations and the upper part of the Scollard Formation. The Lea Park shales at the base of the succession overlie the shales of the Colorado Group.

Within the Upper Cretaceous–Tertiary succession, the Bearpaw shale is part of a second-order transgressive–regressive marine cycle in the Western Interior Basin and spans several third- and fourth-order sea-level cycles (Jerzykiewicz, 1997). During the broad transgressive cycle, the Bearpaw Sea advanced progressively west-northwestward, overlying the estuarine deposits of the Dinosaur Park Formation of the Belly River Group that contain the thin and discontinuous Lethbridge Coal Zone and depositing the marine shales that form the Bearpaw Formation (Figure 16). The Edmonton Group that overlies the Bearpaw Formation and that crops out in southern Alberta over a wide geographic area (Figure 4) represents the last major marine
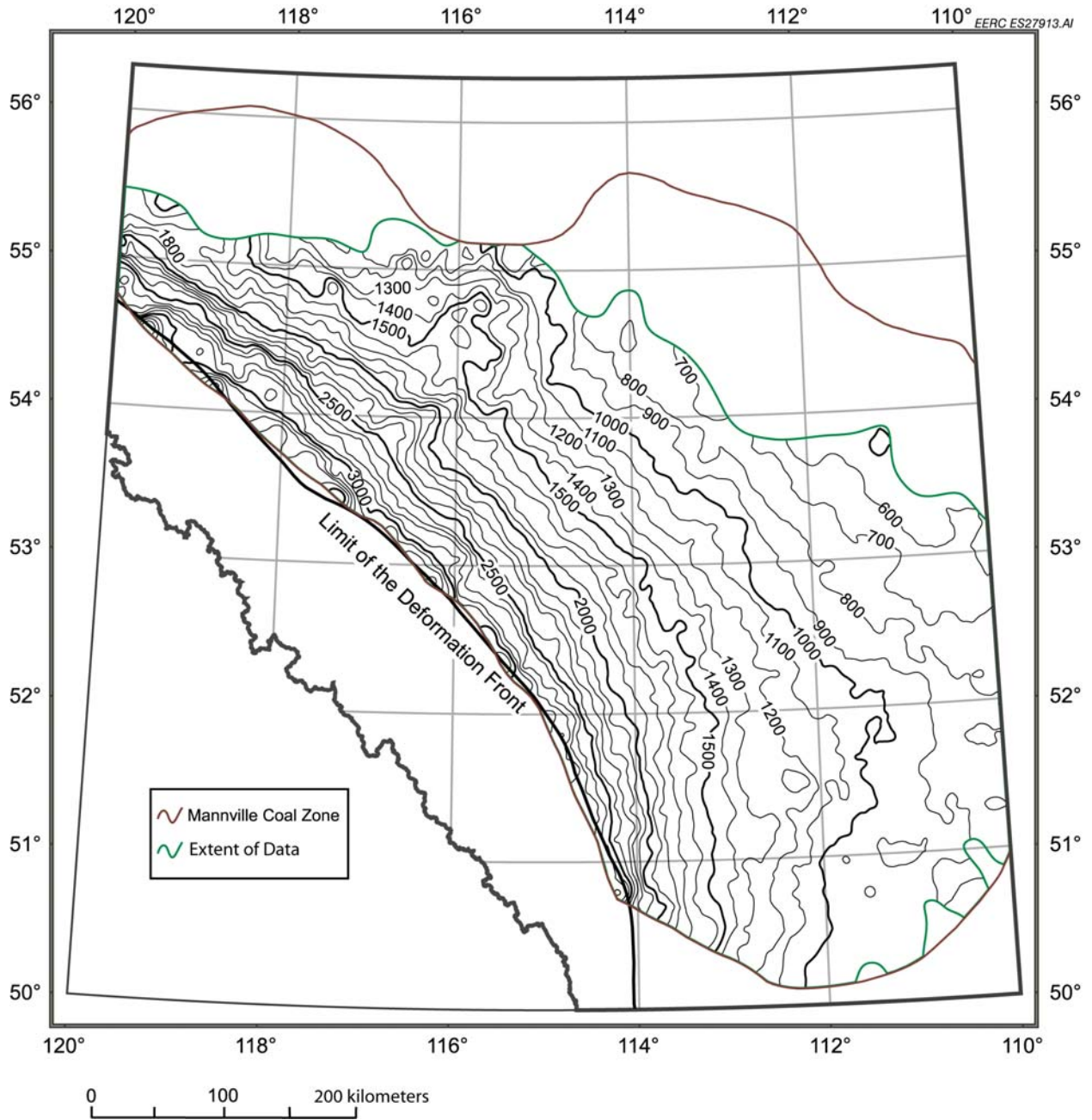
Figure 13. Depth to the top of the Upper Mannville Coal Zone. Contour interval = 100 meters.
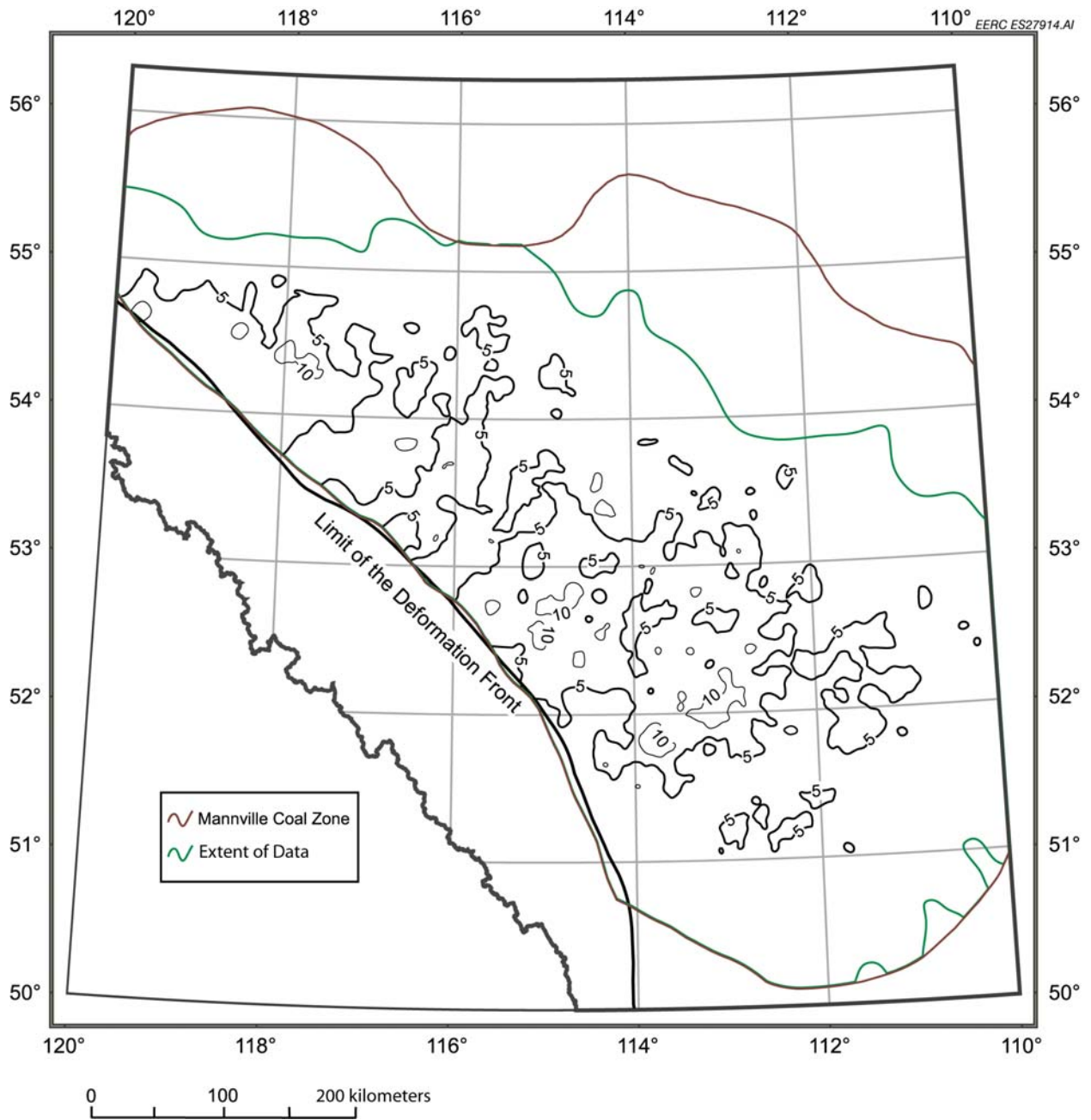
Figure 14. Cumulative coal thickness in the Upper Mannville Coal Zone. Contour interval = 5 meters.

Figure 15. Cardinal River coal mine in the Rocky Mountain foothills, Alberta, where Mannville coal equivalent is being mined in open-pit-mining operations.

transgression preserved in the stratigraphic record of the Alberta Basin. The Bearpaw transgression did not cover the entire basin, such that the shales of the Bearpaw Formation wedge out to the west near the Alberta Syncline, and to the northwest, where the underlying Belly River Group and the overlying Edmonton Group coalesce into the Wapiti Group (Figure 5).

Isostatic relaxation and uplift led to the deposition of the Horseshoe Canyon Formation nonmarine clastic wedge along the western margin of the subsiding Bearpaw seaway. This wedge is characterized by great lateral and vertical facies variability and by bentonite and abundant thin coal beds found in the Drumheller, Daly–Weaver, and Carbon Thompson Coal Zones (Hamblin and Lee, 1997; Jerzykiewicz, 1997). During the broad regressive cycle, the Bearpaw Sea withdrew east-southeastward in a series of third- and fourth-order cycles that produced behind it a fluviodeltaic environment in which the Drumheller coals were deposited (Figure 16). The Horseshoe Canyon Formation is conformably overlain by the fluvial siltstone of the Whitemud Formation, which is, in turn, overlain conformably by the lacustrine shale of the Battle Formation.
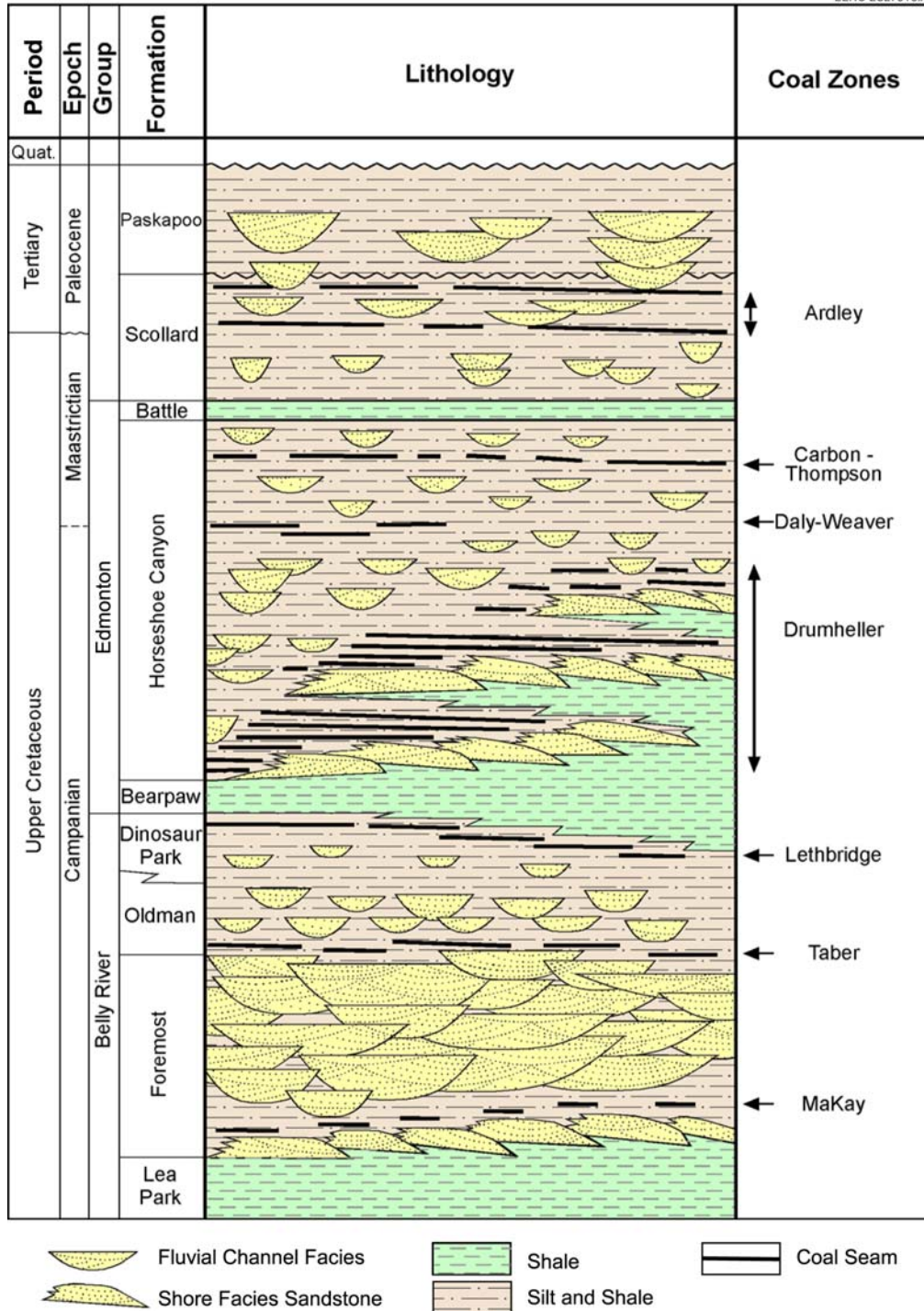
Figure 16. Stratigraphic and depositional model of the Upper Cretaceous–Tertiary coal zones in central Alberta.

Sedimentologically, the Horseshoe Canyon Formation is a broad northwest-southeast progradational clastic wedge that changes from an entirely fluvial sequence in the northwest (Upper Wapiti Group) to a fluviodeltaic sequence in the southeast, intertonguing with and pinching out into the Bearpaw marine shales. The locus of shoreline sandy deposition and the maximum penetration of marine influence shifted progressively southeastward (basinward), such that the seaward limit of sandy deposition of each succeeding cycle overlies and is located southeastward of the preceding one (Hamblin, 2004). The lower Horseshoe Canyon Formation is dominated by several, successively less intense third- and fourth-order marine transgressions, each one of them followed by progradational processes. The depositional environment resulting from these multiple fluviodeltaic and marine interactions generated the main coal accumulations in the Horseshoe Canyon Formation, the Drumheller Coal Zone. The upper Horseshoe Canyon Formation is dominated by fluvial processes that contain the thin and discontinuous coal accumulations of the Daly–Weaver and Carbon–Thompson Coal Zones. The coals in the Drumheller Coal Zone are especially well developed in association with flooding surfaces at the bases of the Bearpaw marine tongues that separate sandy depositional tongues (Figure 16; Hamblin 2004). The coal zone itself can be divided into three subzones: lower, middle, and upper. The lower coals, with up to seven seams, have good quality and continuity. The middle subzone, containing up to 21 seams, is also characterized by good quality and continuity. The upper subzone represents already the transition to a fluvial environment and contains discontinuous coals with few seams and moderate quality.

Depth to the top of the Drumheller Coal Zone varies from less than 41.3 meters at outcrop under Quaternary drift sediments in the east to 1923 m in the west at the Rocky Mountain deformation front (Figure 17). Cumulative coal thickness varies from less than 1 m in the west and northwest to more than 35 m in the east close to outcrop (Figure 18). The total thickness of the Drumheller Coal Zone, comprising the coal seams and intervening layers, varies between less than 1 m at outcrop and 288.4 m. Coal rank reflects depth of burial and varies from subbituminous C in the east to high-volatile C in the west. These coals are mined at shallow depths for power generation (Figure 19) and also are currently the main target for CBM exploration and production in Alberta. However, certain shallow porous and permeable sandstone and coal aquifers, many fractured, represent a prime source of groundwater.

Scollard Formation and Ardley Coal Zone

The Scollard Formation represents part of an eastward-thinning wedge of generally fluvial strata that extends from the late Cretaceous–early Paleocene deformation front to Manitoba and was deposited in a rapidly subsiding basin. The base and top of the Scollard Formation wedge are unconformable, and the Cretaceous–Tertiary boundary divides it into lower and upper members. The lower part is dominated by coarse-grained clastic rocks, whereas the upper part is dominated by finer-grained sedimentary rocks that show an increase in metamorphic rock fragments (Hamblin and Lee, 1997). The upper member, commonly referred to as the Ardley Coal Zone, contains economical coal resources (Dawson et al., 1994). The Paskapoo Formation is a nonmarine, conglomeratic, fining-upward sandstone succession, more than 850 m thick, at the top of the bedrock succession. It unconformably overlies the Ardley Coal Zone at the top of the Scollard Formation

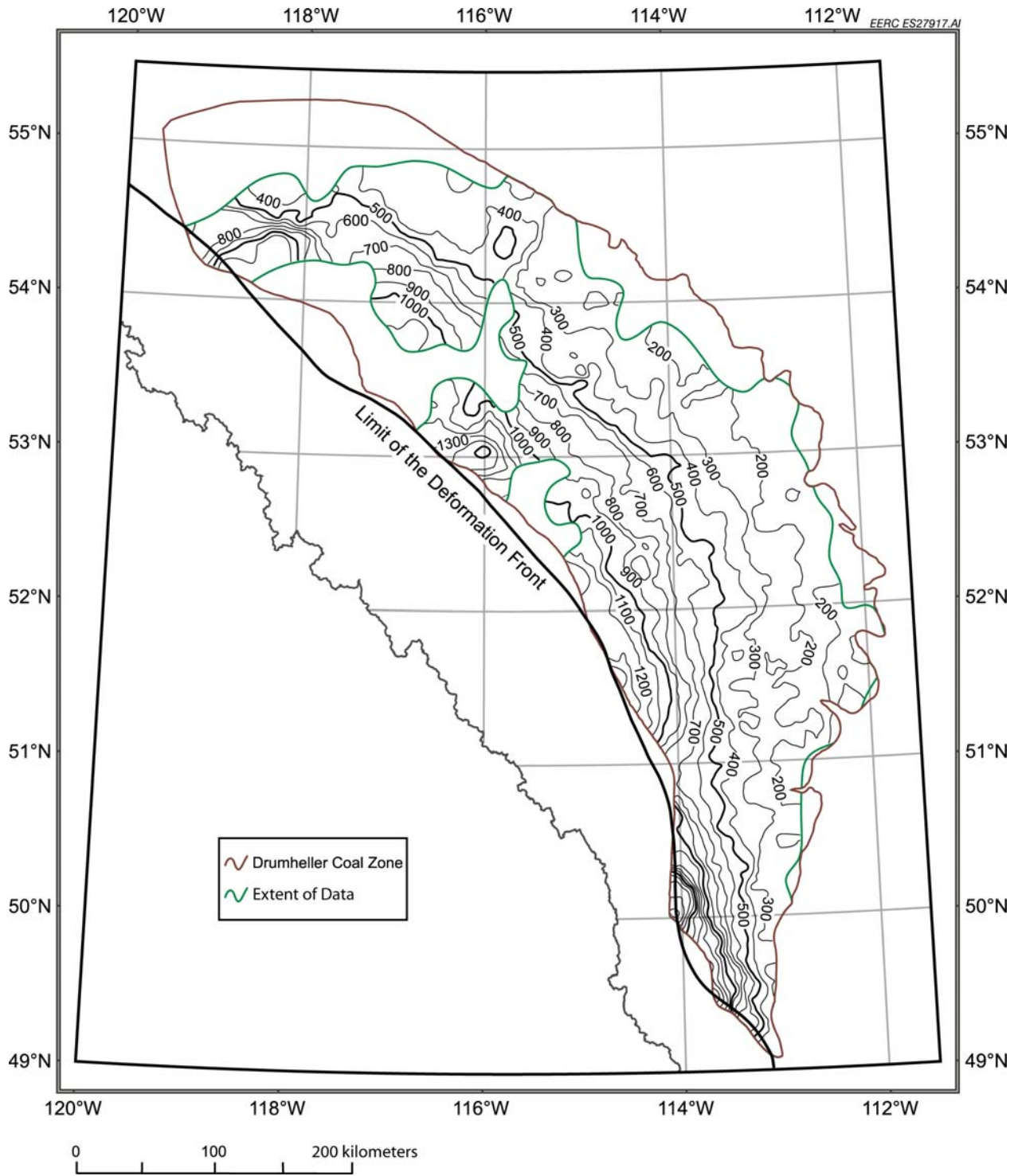Figure 17. Depth to the top of the Drumheller Coal Zone. Contour interval = 100 meters.
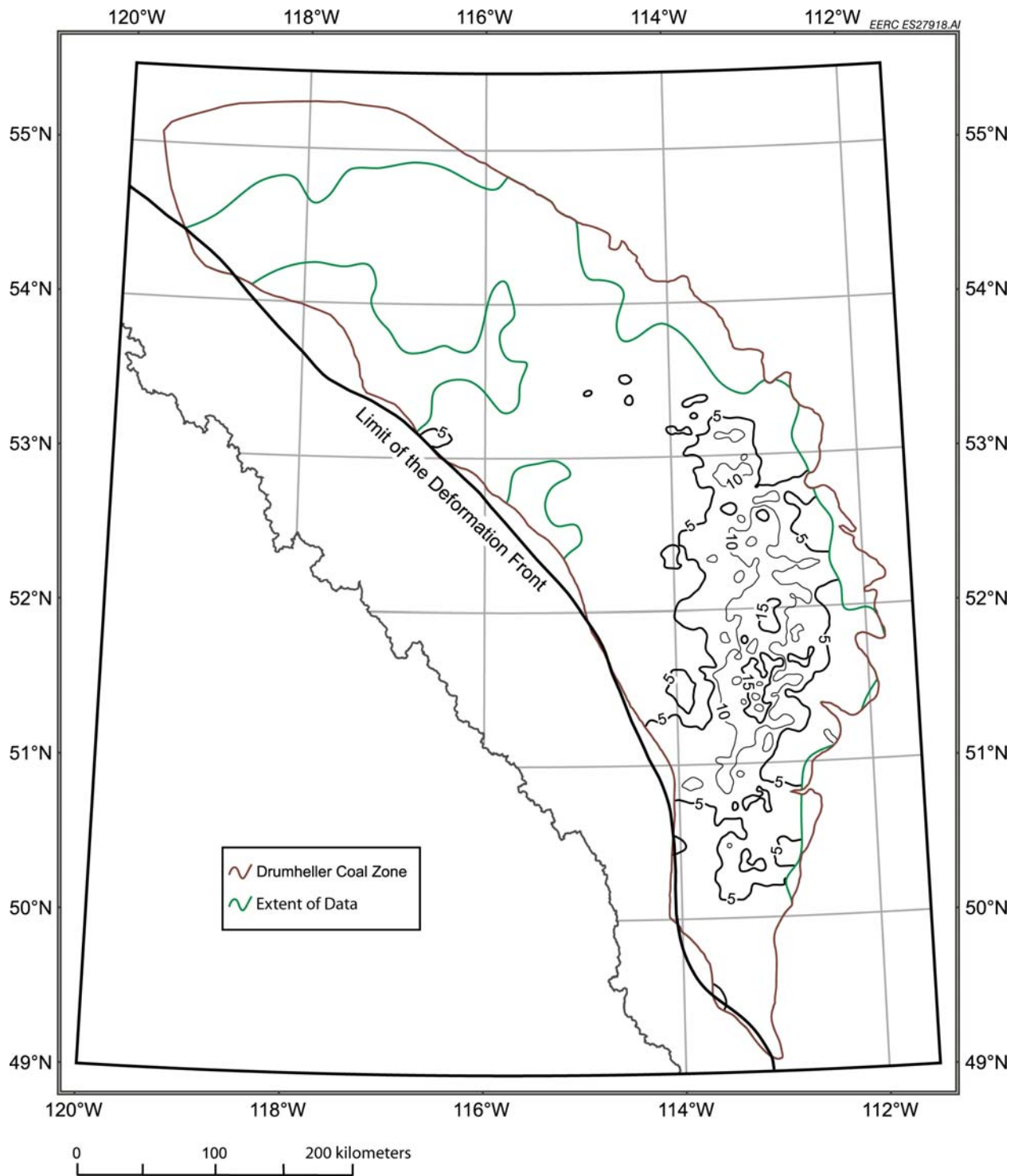
Figure 18. Cumulative coal thickness in the Drumheller Coal Zone. Contour interval = 5 meters.

Figure 19. Upper Drumheller coals in the Horseshoe Canyon Formation at the Sheerness Mine site in east-central Alberta.

(Demchuk and Hills, 1991). Thin coal beds are present throughout the Paskapoo Formation.

The Ardley Coal Zone dips southwestward, like all the strata in the Alberta Basin. The depth to the top of the Ardley Coal Zone (Figure 20) reflects the combined effect of topography (increasing elevation towards the thrust and fold belt and at Swan Hills; Figure 12), and of southwestward strata dipping. Depth varies between a few meters under the Quaternary drift at outcrop at the top of the bedrock in the east to 1160 m in the west at the eastern limit of the thrust and fold belt. The Ardley Coal Zone comprises 8 to 34 individual coal seams that vary in thickness between less than 0.5 m and 11.0 m. The cumulative coal thickness varies between 0.5 m and more than 20 m (Figure 21). The total thickness of the Ardley Coal Zone, comprising the coal seams and intervening layers, varies between 0.5 m at outcrop and 265 m. Coal rank within the Ardley Coal Zone ranges from subbituminous C near outcrop in the east (reflectance less than 0.5%) to high-volatile bituminous B in the west at its deepest, but most of the Ardley coals are high-volatile bituminous C in rank (reflectance 0.5%–0.65%). Ardley coals are mined in open-pit mines for power generation in west-central
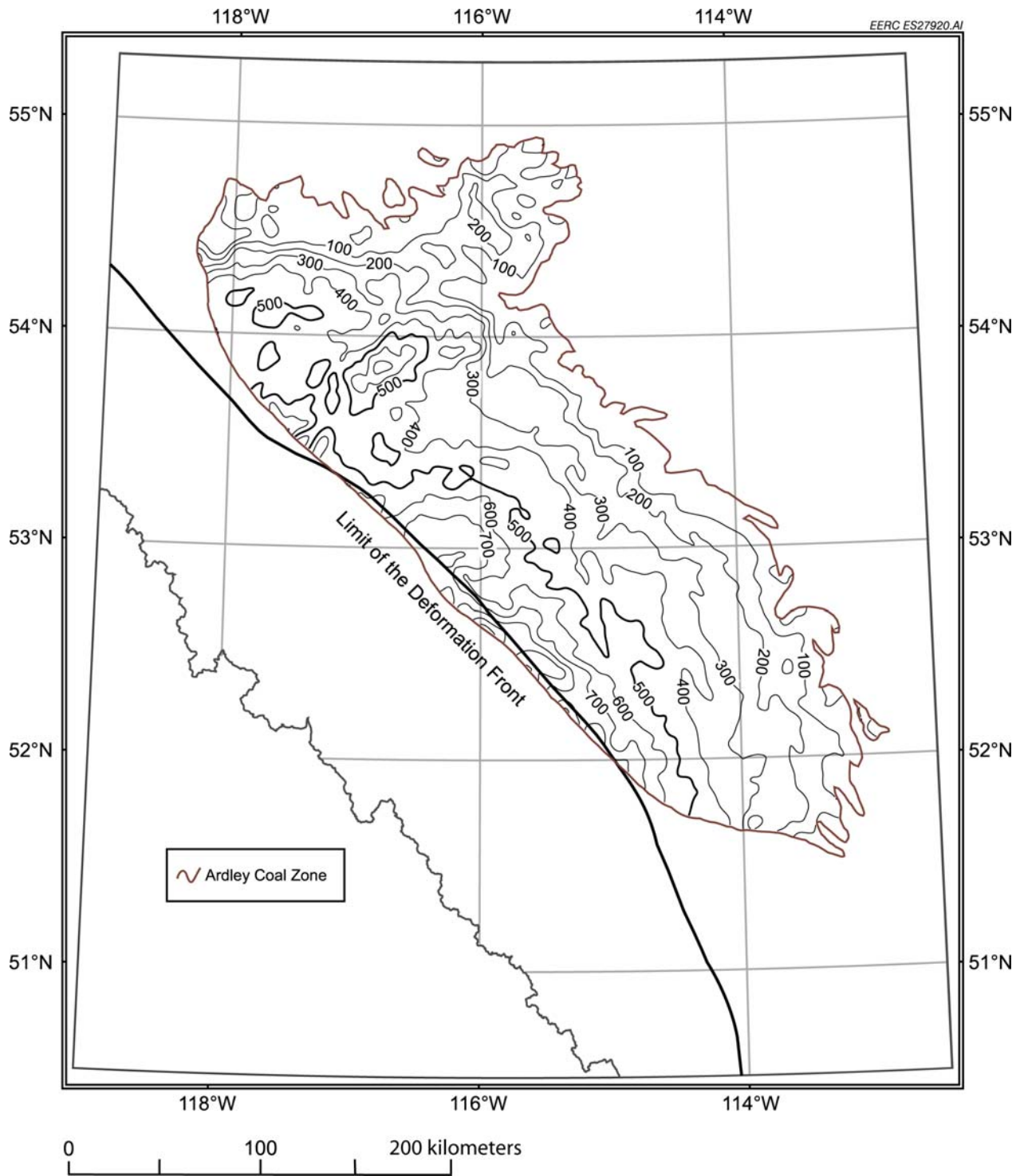
Figure 20. Depth to the top of the Ardley Coal Zone. Contour interval = 100 meters.
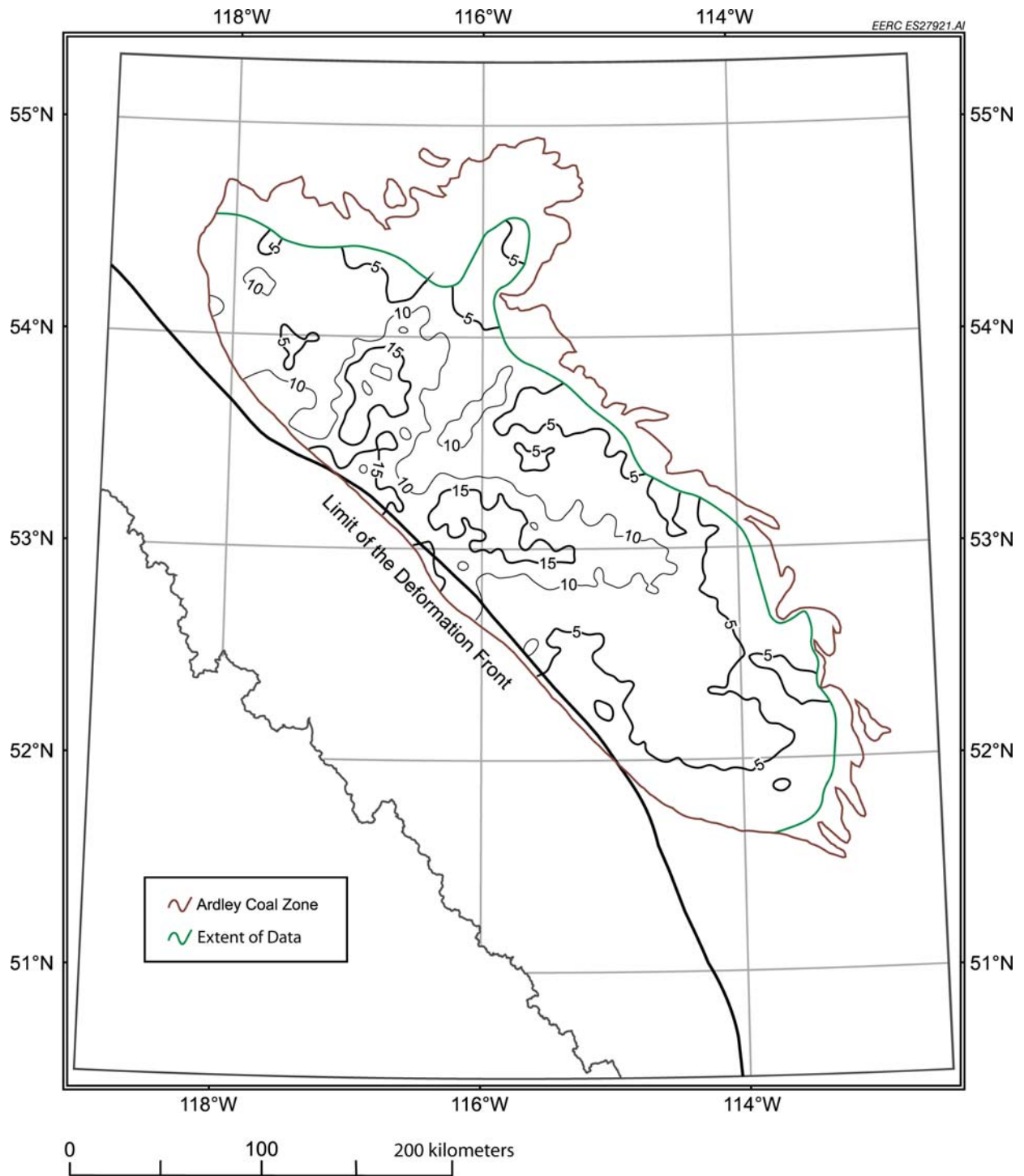
Figure 21. Cumulative coal thickness in the Ardley Coal Zone. Contour interval = 5 meters.

Alberta (Figure 22).The Ardley coal seams can be grouped in four "subzones" listed in descending order: Val D'Or, Arbour, Silkstone, and Mynheer. The "upper" Ardley comprises the Val D'Or and Arbour seams, and the "lower" Ardley comprises the Silkstone and Mynheer seams. The coal seams are separated by shales, silts, sandstone, channel sands, and bentonites up to 50 cm thick. Thick Paskapoo channel sands cut in places down to the Val D'Or coal seam (Figure 16). Similarly, thick, continuous stacked channel sands between the upper and lower Ardley (Arbour and Silkstone subzones) are in direct contact in places with the top of the Silkstone coal seams. The coal seams are discontinuous in places. The channel sands are most likely water-saturated, although they may be gas-bearing in places. These channel sands, where in contact with the coal seams, most likely compromise reservoir integrity and may constitute a pathway for CO_2 migration if it is not adsorbed in the coal or for methane displaced by the injected CO_2.

Figure 22. Mining of Ardley coals in open-pit-mining operation at the Whitewood Mine in west-central Alberta.

Hydrogeological, Stress, and Geothermal Regimes

Hydrostratigraphically, the Cretaceous–Tertiary strata in the southern half of Alberta form a succession of aquifer and aquitard systems (Figure 5). An aquifer system behaves generally like an aquifer although it contains some aquitards, while an aquitard system is the opposite. As an example, the Mannville Group, although it contains shales, behaves like a single auquifer particularly in the southern partof Alberta where the Clearwater shales are absent. Similarly, the thin sandstone formations embedded in the thick Colorado Group shales are isolated aquifers, but the entire Colorado Group forms a thick, competent aquitard that separates the Mannville aquifer system from the aquifers in the Upper Cretaceous–Tertiary succession.

Flow of Formation Water

An unconfined aquifer is present at the top of the succession, comprising Quaternary unconsolidated sediments and sandstones that crop out at the top of the bedrock. The position of the water table in this aquifer was constructed using information filed with Alberta Environment regarding the water level in 184,271 water wells used for potable water in southern and central Alberta and topographic information regarding the water elevation in rivers and lakes to which the shallow groundwater aquifers are connected. The water table (Figure 23) mimics the topography (Figure 12), varying in depth from 0 to 40 m below the ground surface. The deep incisions by the valleys of the Athabasca and North Saskatchewan Rivers are particularly evident (Figure 23). The water is of meteoric origin and has low salinity, generally less than 1000 mg/L, which qualifies it as potable water. This aquifer is the main source of groundwater for domestic, industrial, and agricultural use. The flow of groundwater in this aquifer is very local in nature, from a topographic high to the nearest topographic low, usually a lake or a river valley. However, on a basin scale, the elevation of the water table drops from ~1200 m at the easternedge of the Rocky Mountain foothills in the southwest to less than 600 m in the northeast (Figure 23).

If the entire sedimentary succession would be a single aquifer, then the water table would represent the potentiometric surface (hydraulic heads) at any depth in the succession anywhere in the basin, the flow of formation water would be from the southwest to the northeast, and pressures would be hydrostatic from the water table to that depth. However, the flow of formation water in the succession is much more complex, several flow systems are present in the sedimentary succession of interest, and pressures are not hydrostatic. Generally, the Alberta Basin is underpressured, except for the Cretaceous strata in the deep foreland basin where recent and current hydrocarbon generation creates overpressures in tight formations, including the Mannville Group (Bachu, 1999). On the other hand, erosional and postglacial rebound in the thick shales in the Cretaceous succession generated severe underpressuring in intervening sandstone aquifers such as Mannville, Viking, Belly River, and Horseshoe Canyon (Bachu and Underschultz, 1995; Anfort et al., 2001; Michael and Bachu, 2001; Bachu and Michael, 2003).

Upper Mannville. Flow in this aquifer system is the most complex of all coal-bearing strata in the Alberta Basin. A basin-scale, long-range flow system is present in the eastern part of the area where coal seams occur, driven north-northwestward from
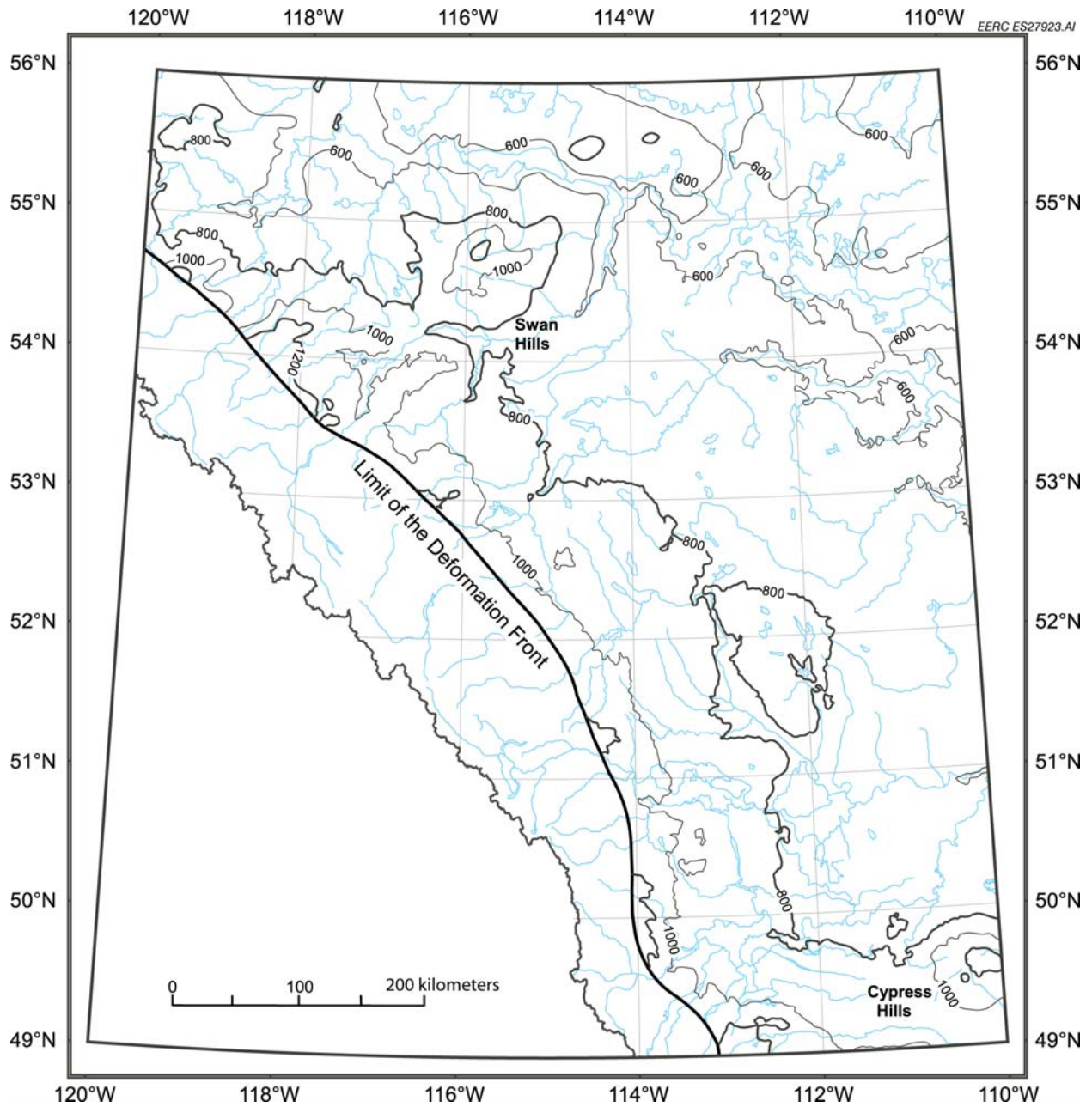
Figure 23. Elevation of the water table in the study area. Contour interval = 200 meters.

recharge areas at outcrop in Montana to discharge areas in northeastern Alberta (Figure 24a) (Bachu, 1999; Anfort et al., 2001). This basin-scale flow system is fed laterally from the southwest by regional-scale flow systems present in Mannville Group strata and in underlying Paleozoic aquifers that subcrop at the pre-Cretaceous unconformity with successively increasing age from west to east. In these regions, the Upper Mannville Aquifer is underpressured. Another regional-scale flow system is present in the northwest (Figure 24a). In the "Deep Basin" in the southwest, along the Rocky Mountain deformation front, the Mannville Group strata are gas-saturated rather than water-saturated and overpressured as a result of current gas generation Figure 24a) (Masters, 1979; Michael and Bachu, 2001). Salinity of formation water in the Upper Mannville Aquifer is quite high, ranging from 2500 mg/L at its shallowest in the extreme northeast to more than 130,000 mg/L (Figure 25a). Because formation waters in Paleozoic aquifers are much more saline than in Cretaceous aquifers (Bachu, 1999) and because freshwater of meteoric origin did not penetrate deep into this aquifer from recharge areas in the south, a plume of high-salinity water is present in the center of the Mannville Aquifer mainly along the subcrop of Devonian aquifers (Figure 25a).

The coals in the Upper Mannville Coal Zone are gas-saturated in the deep basin in the west; otherwise, they are saturated with saline formation water (brackish and brine). If CBM is produced from these "wet" coals, in conjunction or not with CO_2 sequestration, the water that will be produced concurrently with the gas will have to be disposed of through deep-well injection.

Pressures at the base of the Upper Mannville Coal Zone were calculated on the basis of drillstem tests, and they reflect mainly the effect of southwestward increasing depth and underpressuring (Figure 26). They vary from 3200 kPa in the northeast to 29,530 kPa in the southwest at the Rocky Mountain deformation front, showing that the Upper Mannville strata are significantly underpressured. If the pressure would have been hydrostatic, they would have ranged from close to 4750 kPa in the northeast to ~36,000 kPa in the southwest, corresponding to the depth of the coal zone (Figure 13). The underpressuring affects the CBM content and CO_2 sequestration capacity of the coal seams because less gas is adsorbed onto the coal at lower pressures. As expected, because of their depth, most of the coals in the Upper Mannville Group are at pressures higher than the CO_2 critical pressure (7380 kPa); only in the northeast are pressures less (Figure 26).

Horseshoe Canyon. The flow of formation water in the deep parts of the Belly River Group and the Horseshoe Canyon Formation is driven downdip, inward toward the Rocky Mountain deformation front by erosional and postglacial rebound (Figures 24b and 24c, respectively) (Bachu and Underschultz, 1995; Bachu and Michael, 2003). These two systems are severely underpressured, with underpressuring increasing toward the Rocky Mountains. Capillary sealing between downdip gas-saturated sandstone and updip water-saturated sandstone and low-permeability depositional barriers in both the Belly River and Edmonton Groups create flow barriers that hinder the inward flow of meteoric water from outcrop areas in the east that would equilibrate pressures in these aquifers with current basin topography (Bachu and Michael, 2003). The underpressured sink in the central-western part of these aquifers also draws fresh meteoric water from recharge areas at high elevation in the northwest at the Swan Hills and in the south-southeast (Figures 24b and 24c). Because fresh meteoric water
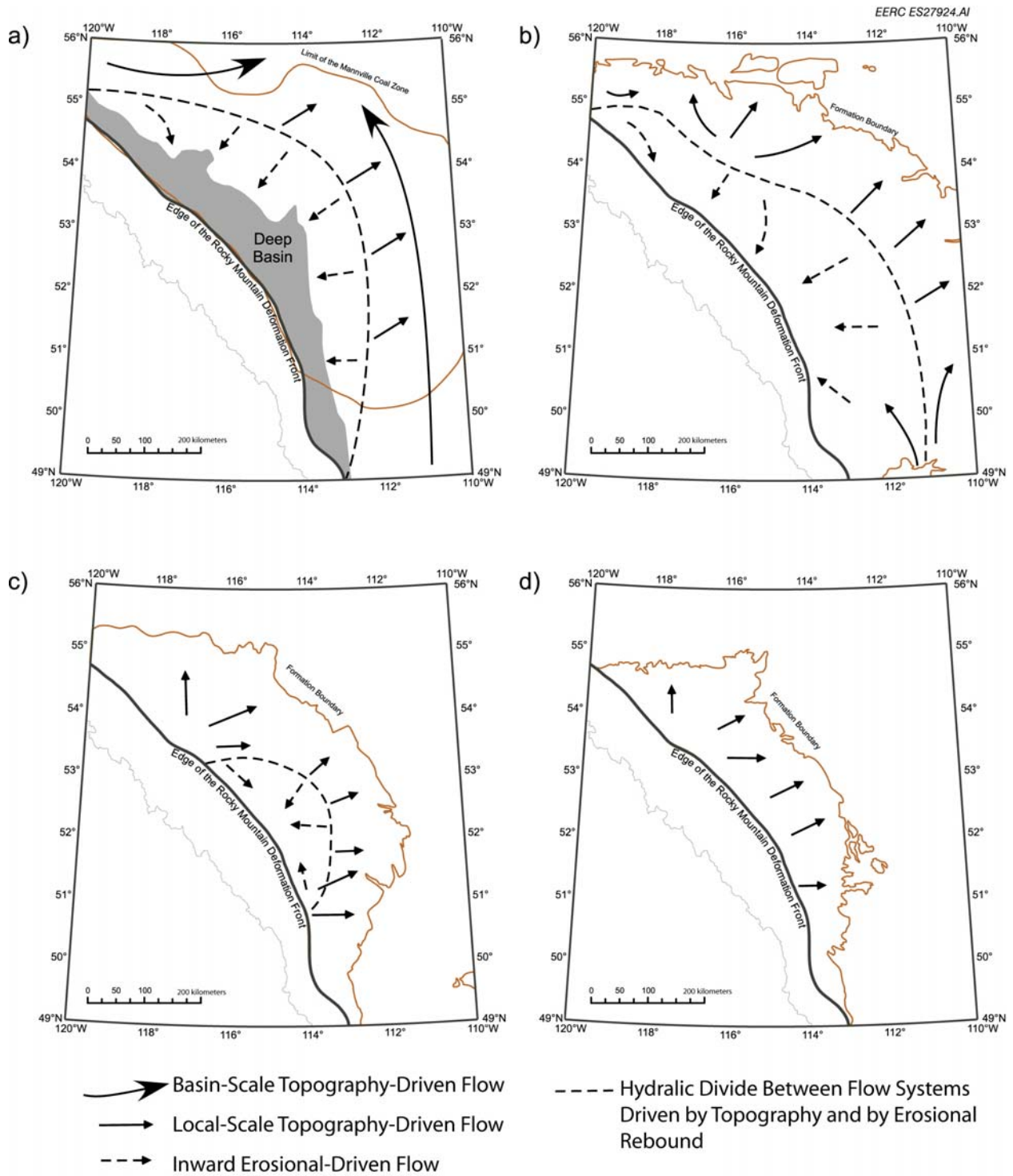
Figure 24. Diagrammatic representation of the flow systems in Cretaceous–Tertiary coal-bearing strata in the Alberta Basin: a. Upper Mannville Group; b. Belly River Group; c. Horseshoe Canyon Formation; and d. Scollard Formation.

Figure 25. Salinity of formation water in Creataceous–Tertiary coal-bearing strata in the Alberta Basin: a. Upper Mannville Group; b. Belly River Group; c. Horseshoe Canyon Formation; and d. Scollard Formation.
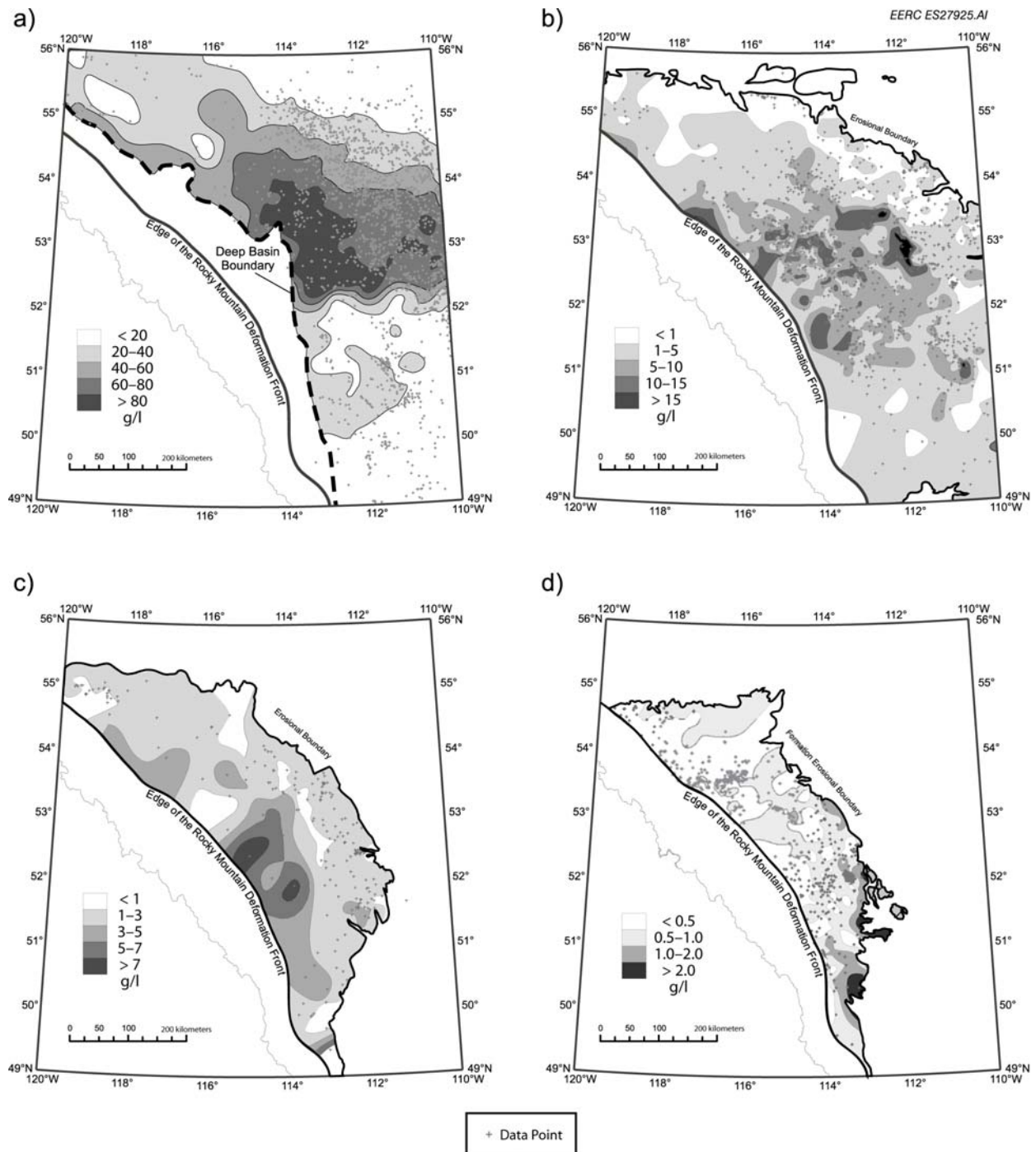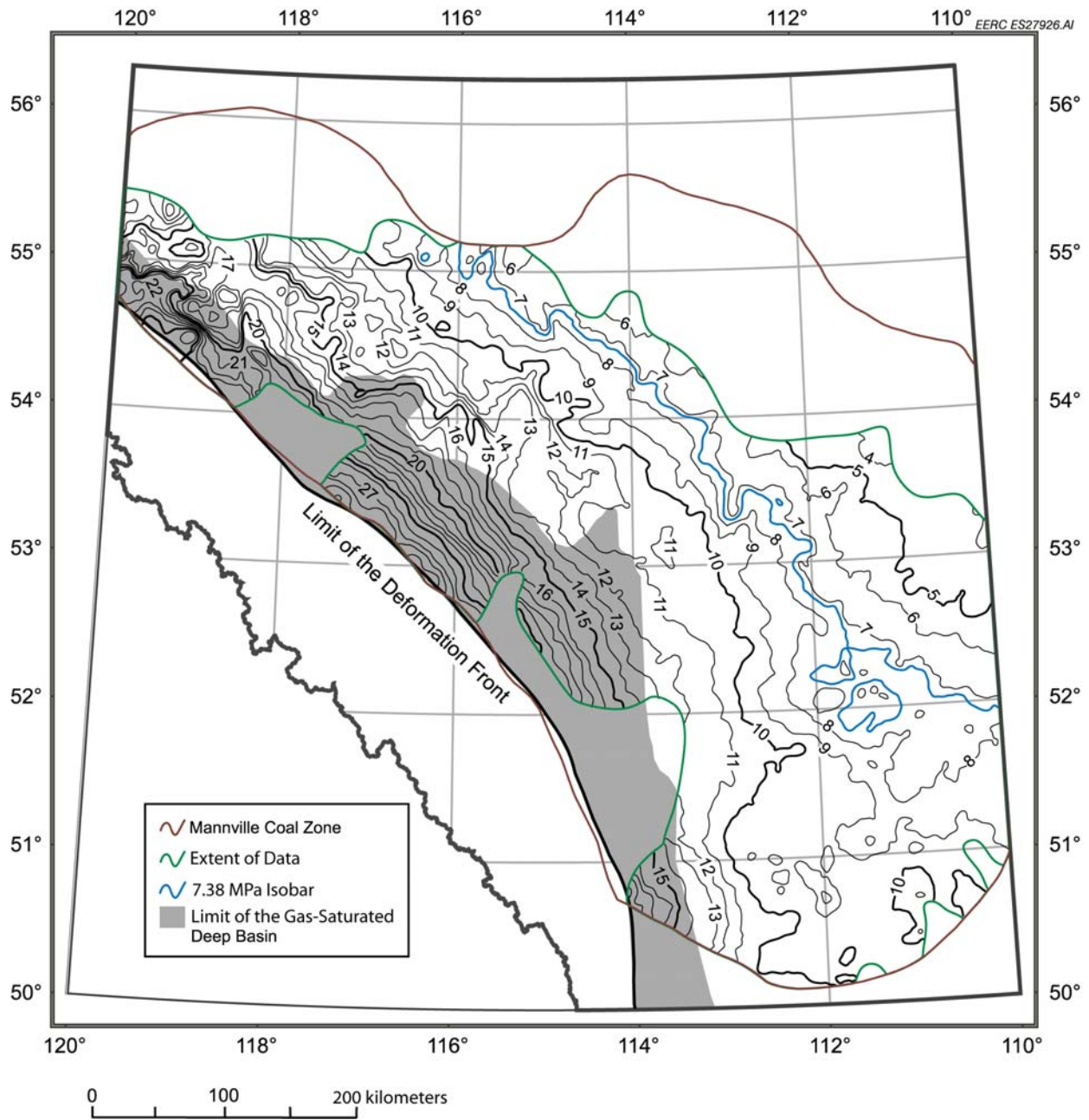
Figure 26. Pressure distribution at the base of the Upper Mannville Coal Zone.
Contour interval = 1 MPa.

did not penetrate the deep portion of these aquifers to dilute the original connate water, the salinity of formation waters in these aquifers in this area, although significantly less than the salinity in the Upper Mannville Aquifer, is relatively high (between 5000 and 18,000 mg/L) compared to outcrop areas where it is less than 2000 mg/L (Figures 25b and 25c, respectively). Thus formation water in the recharge and outcrop areas of these aquifers qualifies as potable, protected groundwater (salinity less than 4000 mg/L), while formation water in the deep central areas of these aquifers does not.

The normal decrease in pressure caused by uplift since maximum burial and since the retreat of the 2-km-thick ice sheet that covered the region most likely caused gas desorption from the coal beds and migration into adjacent sandstone reservoirs, where it has accumulated in stratigraphic traps. The additional loss of pressure (underpressuring) caused by erosional and postglacial rebound in the intervening shales enhanced the gas desorption and migration out of coal beds into the adjacent sandstone units, which explains the large number of gas pools in the Belly River and Edmonton Groups. Pressures at the base of the Drumheller Coal Zone vary from less than 500 kPa at the eastern edge of the coal zone to ~17,000 kPa near the Rocky Mountain deformation front (Figure 27). However, the increase in pressure is not uniform, such that most of the coals are found at pressures less than the CO_2 critical pressure (7380 kPa; Figure 27). To illustrate the severity of undepressuring in the Drumheller Coal Zone, Figure 28 shows the difference between the hydrostatic pressure corresponding to the elevation of the water table and the actual pressures. Underpressuring increases from zero at outcrop of the Horseshoe Canyon Formation to more than 6000 kPa in the west and up to 9000 kPa in the southwest. The underpressuring reduces gas content of the coal seams because less gas is adsorbed onto the coal at lower pressures; hence, lower-than-normal sequestration capacity should be expected in the Drumheller Coal Zone than for identical coals under hydrostatic conditions. As a result of underpressuring and permeability and capillarity barriers to recharge by meteoric water, the coals in the Drumheller Coal Zone are gas-saturated, such that no water is produced with CBM, obviating the need for water disposal. The coals are water wet and, actually, they form shallow aquifers only in the outcrop areas.

Scollard Formation. The flow systems in the aquifers that crop out at the top of the bedrock progressively from west to east (Scollard–Paskapoo, Edmonton–Upper Wapiti, and Belly River) are in equilibrium with and driven by the present-day topography from recharge areas at high elevation in the Swan Hills and near the thrust and fold belt to discharge areas in the east-northeast (Figures 23 and 24b–d) (Bachu and Michael, 2003). For the Belly River and Horseshoe Canyon Aquifers, this area corresponds to the easternmost water-saturated sandstones. The Scollard–Paskapoo Aquifer is basically unconfined. Given the meteoric origin of formation water, salinity in these areas is low, less than 2000 mg/L (Figures 25b–d). Water in these strata is defined as potable groundwater and, as such, is protected under Alberta Environment regulations. The coals are "wet," i.e., water-saturated, and low-salinity freshwater will be produced concurrently with CBM production and CO_2 sequestration. Given the low salinity of this water, it may be possible to dispose of it at the surface.
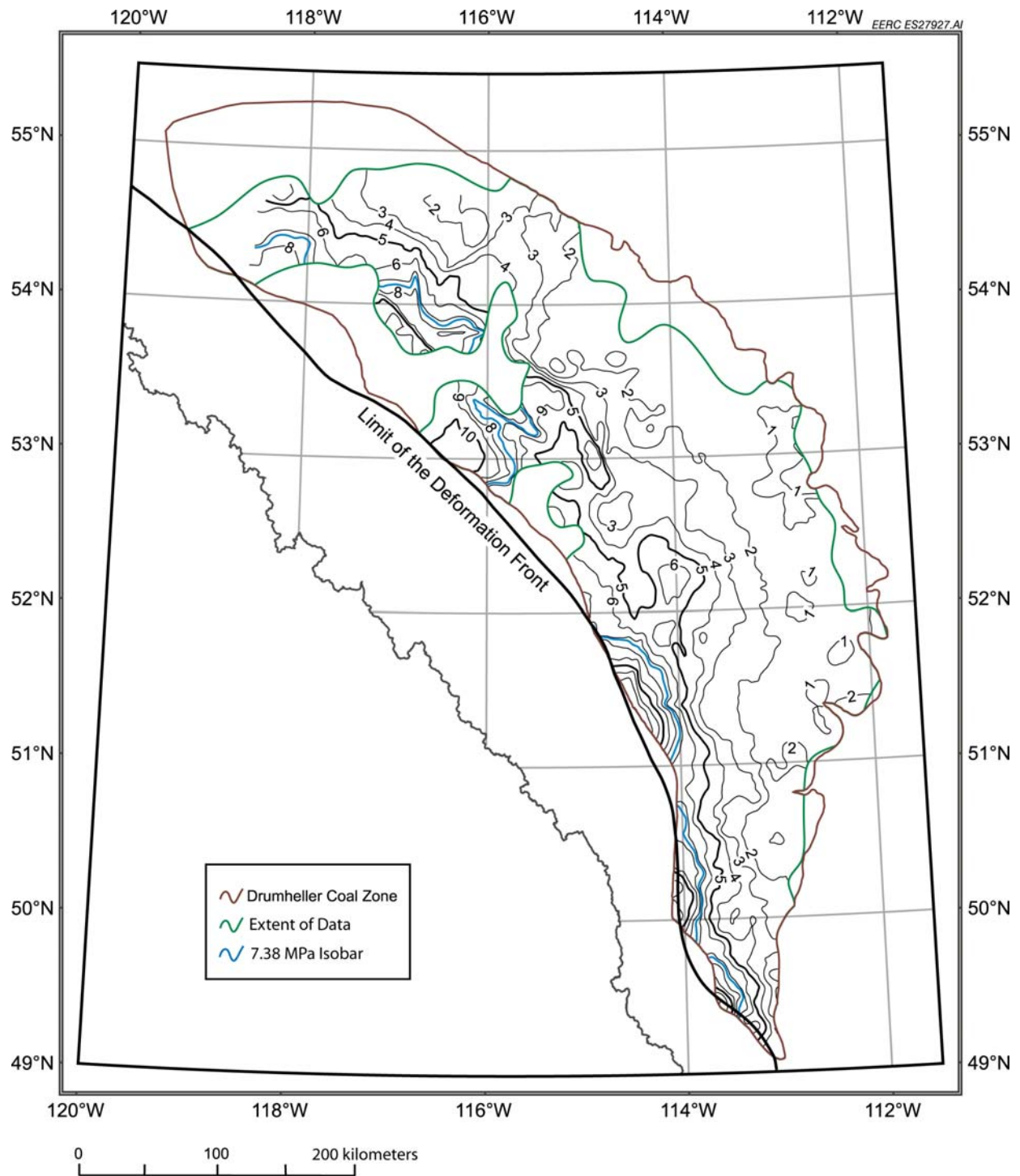
Figure 27. Pressure distribution at the base of the Drumheller Coal Zone. Contour interval = 1 MPa.
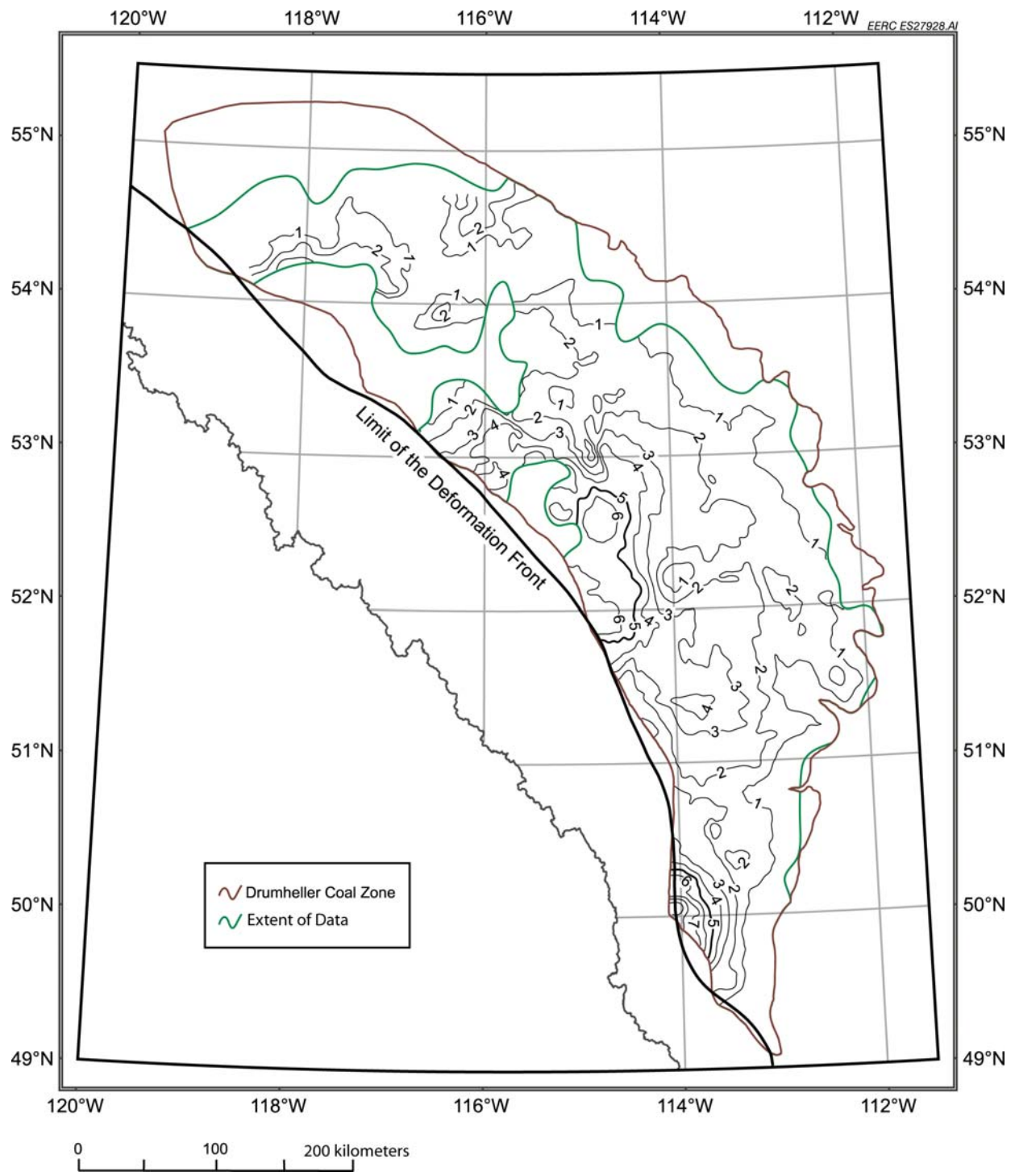
Figure 28. Pressure difference between hydrostatic and actual pressure at the base of the Drumheller Coal Zone. Contour interval = 1 MPa.

Pressures in the Ardley Coal Zone are generally hydrostatic, increasing linearly with depth from the water table (Figure 23), with a gradient of ~9.8 kPa/m. The distribution of pressures at the base of the Ardley coals (Figure 29) reflects the depth of the Ardley Coal Zone from the water table and its total thickness. Pressures reach more than 7380 kPa (CO_2 critical pressure) only in its deepest part close to the Rocky Mountain deformation front (Figure 29).

Coal Permeability and Stress Regime

Gas migration within coal, either natural or induced during CBM production and/or CO_2 injection, takes place by a combination of desorption/adsorption, diffusion, and free-phase flow and occurs as a direct result of changes in pressure. Because the permeability of the coal matrix is extremely low, fluid conductivity in coal depends upon fracture, i.e., cleat development and permeability (McKee et al., 1988; Montgomery, 1999). Production rates of CBM and, conversely, injection rates for CO_2 are extremely sensitive to reservoir properties, of which permeability is critical (Schraufnagel, 1993; Zuber et al., 1996). Increasing the confining pressure can cause the permeability to decrease by as much as 3 orders of magnitude, usually declining exponentially with stress (Puri and Seidle, 1992). Furthermore, coal porosity and permeability generally decrease as coal rank increases (White et al., 2005).

Low permeability is one of the leading reasons for the lack of CBM development in Rocky Mountain basins (Montgomery, 1999). Coal permeability depends largely on the fracture (cleat) density, width, and orientation. Cleats, which occur in two orthogonal systems (face and butt cleats) nearly perpendicular to bedding, are the result of a number of interdependent factors, including paleotectonic stress(Close, 1993). Regardless of the quantity of GIP, there is a permeability value below which the resource cannot be produced economically, estimated to be 10^{-15} m^2 (1 mD; Zuber et al., 1996). The general consensus is that CBM cannot be produced from coals deeper than 1500 m because of the lack of coal permeability.

Data from the Piceance, San Juan, and Black Warrior Basins in the United States and from the Sydney and Bowen Basins in Australia document a decrease in permeability with increasing burial depth and effective stress (McKee et al., 1988; Enever et al., 1994, 1999; Sparks et al., 1995; Bustin, 1997) and, in the absence of direct permeability measurements, this dependence can be used to infer coal permeability. The effective stress, σ_{ef}, is defined as:

$$\sigma_{ef} = \sigma - P \qquad (2)$$

where σ is the total stress and P is pore pressure. This relation can be written also as:

$$\sigma_{ef} = (G_\sigma - G_P) \times D \qquad (3)$$

where G_σ and G_P are the stress and pressure gradients, respectively.
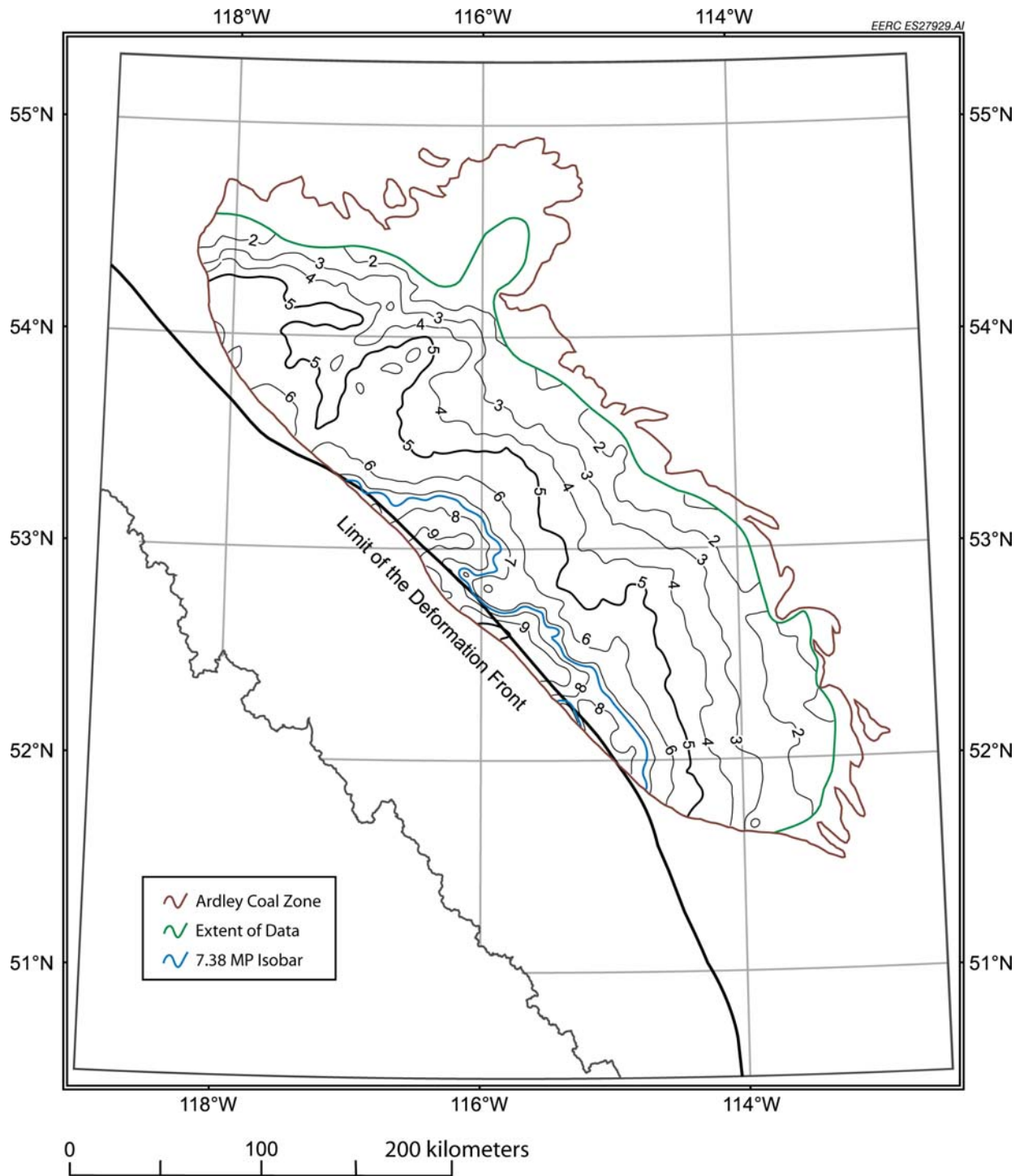
Figure 29. Pressure distribution at the base of the Ardley Coal Zone. Contour interval = 1 MPa.

McKee et al. (1988) suggest a relationship between coal permeability and effective stress of the form:

$$k = k_0 \frac{e^{-a\sigma_{ef}}}{1 - \phi_0(1 - e^{-a\sigma_{ef}})} \qquad (4)$$

where ϕ_0 and k_0 are porosity and permeability at the reference effective stress. Taking into account the range of porosity and depths, relation (4) becomes (McKee et al. 1988):

$$k \approx k_0 e^{-a\sigma_{ef}} \qquad (4')$$

If relation (3) is substituted into relation (4'), then relation (4') becomes:

$$k \approx k_0 e^{-A \times D} \qquad (5)$$

which shows the exponential decrease of coal permeability with depth.

Although coal permeability is one of the most critical parameters for CBM productibility, there is very little information regarding the permeability of the deeper coal beds in the Upper Cretaceous–Tertiary succession of the Alberta Basin, but the available data generally indicate low permeability (Dawson, 1995). Table 2 and Figure 30 show the magnitude and distribution of coal permeability data that are currently available in the public domain. Coal permeability is low, in the order of a few milidarcies (i.e., lower by 1 order of magnitude than coal permeability in the San Juan Basin).

The first three permeability values in Table 2 seem anomalously low. If these values are not considered, these very few measurements suggest that coal permeability decreases exponentially with depth according to the relation:

Table 2. Coal Permeability Measured on Samples from Cretaceous–Tertiary Coals in Alberta

| Sample No.	Location	Coal Zone	Depth	Permeability
1	11-01-56-19W5Mer	Ardley	592.0	0.46
2	09-34-38-28W4Mer	Ardley	287.0	0.22
3	08-16-45-07W5Mer	Ardley	412.8	1.20
4	15-06-47-07W5Mer	Ardley	420.0	7.00
5	11-06-56-19W5Mer	Ardley	825.0	5–10
6	08-10-47-04W5Mer	Ardley	250.0	<5.0
7	13-02-37-28W4Mer	Ardley	265.0	5.80
8	14-15-46-10W5Mer	Ardley	581.0	4–7
9	16-32-34-21W4Mer	Horseshoe Canyon	344.5	4.9
10	04-23-36-20W4Mer	Upper Mannville	1254.0	1.18
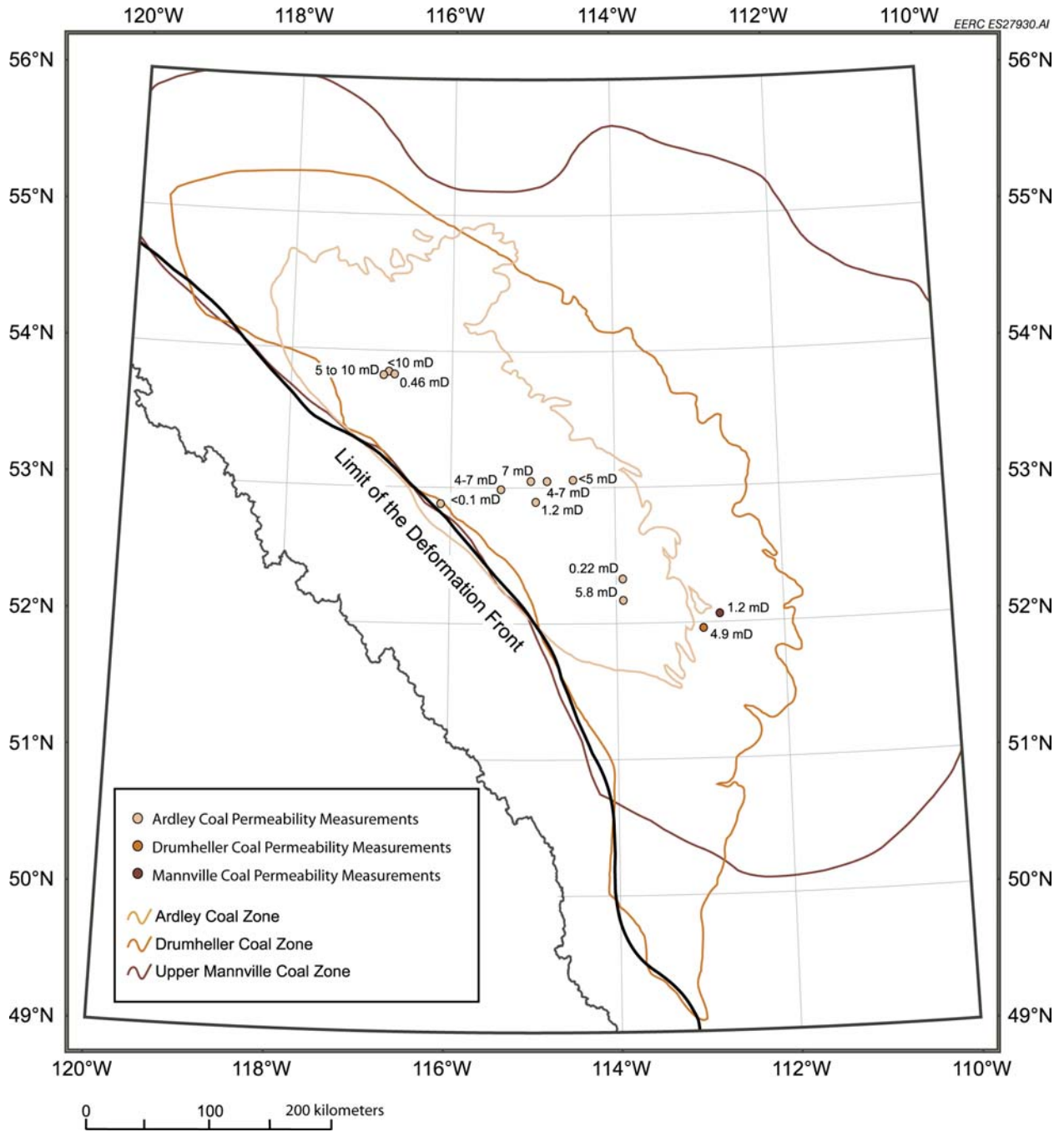
Figure 30. Permeability of coal seams in Alberta.

$$Ln(k) = -\frac{1322.1 - D}{528.12}; \; R^2 = 0.72 \qquad (6)$$

or

$$k = 9.05e^{-0.0014D} \qquad (6')$$

where k is permeability in millidarcies, and D is depth in meters. The above relationship would suggest coal permeability values of ~9 mD near the surface and 1 mD at ~1300 m depth. These data are too few to draw a definitive conclusion, and the surface permeability is too low for any realistic cases, but they tend to confirm previous conclusions about the exponential decrease of coal permeability with depth (Puri and Seidle, 1992). As exploration for CBM intensifies in the basin, more data are likely to become available and this relationship should improve.

During the 1970s, the Groundwater Department of the Alberta Research Council conducted a program of hydrogeological mapping of shallow aquifers used for potable water in Alberta. A series of shallow coal aquifers (less than 100 m deep) were tested and sampled as part of that program; unfortunately, the original data have been lost. Synthesis information survived at the Alberta Geological Survey as an unedited and unpublished draft of a 1979 Alberta Research Council Earth Sciences Bulletin by D. Chorley and R.I.J. Vogwill, entitled *Coal Aquifers in Alberta*, and this information is used in this report to infer the permeability of shallow coals. The data set consisted of 405 "apparent hydraulic tests," 45 long-term aquifer tests, and 120 chemical analyses of water sampled from shallow coal seams (less than 100 m depth), distributed in two arcuate bands from northwest of Edmonton to southeast of Calgary (Figure 31). Most of the tests (the eastern band) are from coals in the Edmonton and Wapiti Groups (i.e., equivalents), but some tests are from the region at the eastern limit of the Ardley Coal Zone. The aquifer tests were used for estimations of hydraulic conductivity, whose values are reported in m/d. Depending on the value considered for freshwater viscosity, the permeability k can be estimated from hydraulic conductivity K using the relation:

$$k \text{ (mD)} \approx 1200\text{–}1500 \; K \text{ (m/d)} \qquad (7)$$

The distribution of hydraulic conductivity data indicates two populations: less than 50 m depth and between 50 m and 100 m depth. The average hydraulic conductivity of the very shallow coal aquifers is 19 m/d (permeability of approx. 25–30 D) at 5–15 m depth and then gradually decreases. The average hydraulic conductivity of the slightly deeper coal aquifers (between 50 and 100 m depth) is fairly constant at 2 m/d (permeability of approximately 2.5–3 D). A frequency plot of the two populations (Figure 32) indicates that they are generally distributed log normally. The permeability data for both shallow and deeper coals indicate that coal permeability decreases rather rapidly and that coals that would normally be the target for CBM production and/or CO_2 sequestration have low permeability.

If the data from the hydraulic tests performed by the Alberta Research Council in the late 1970s are considered as two additional coal permeability values at ~10 and
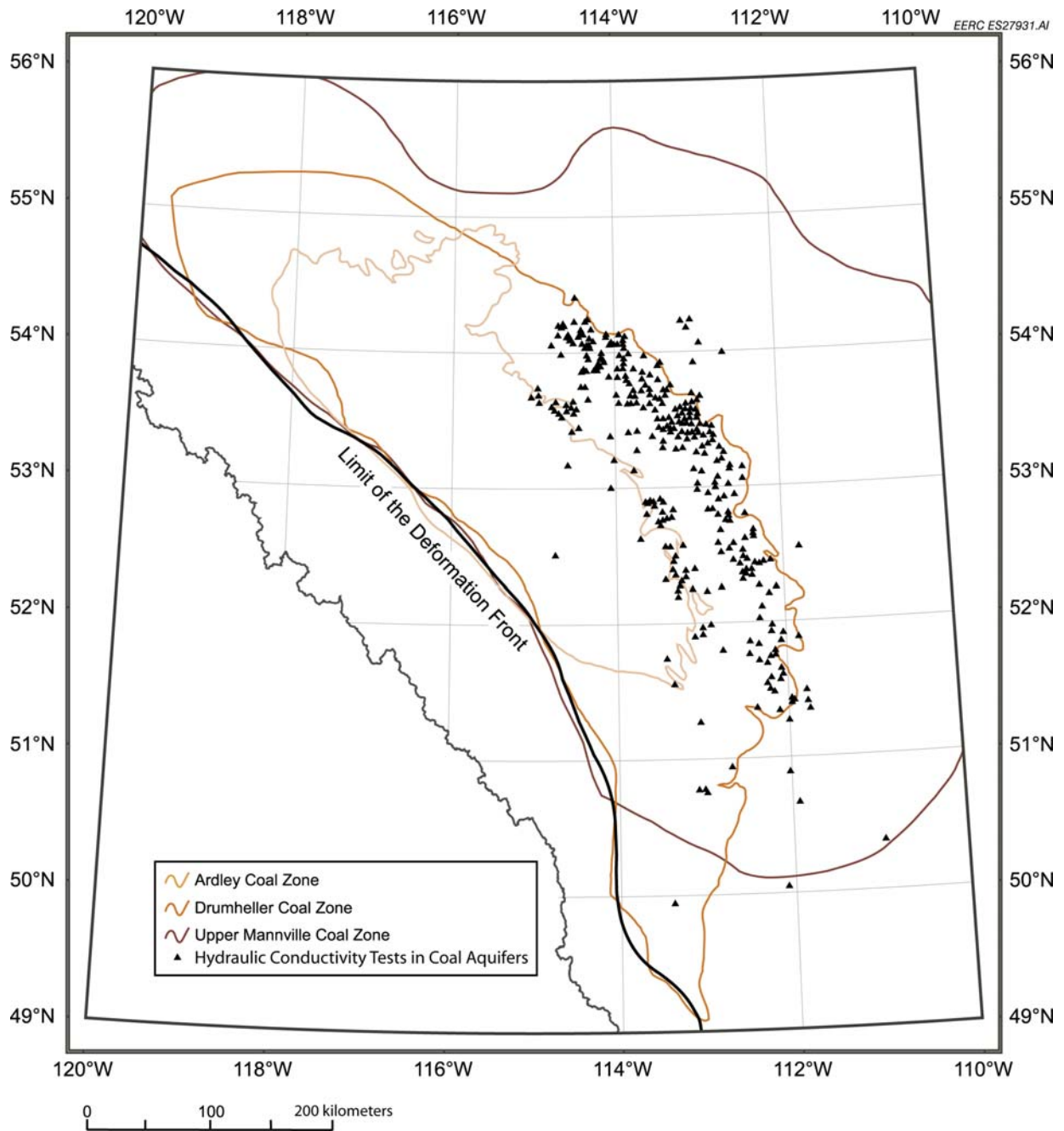
Figure 31. Distribution of coal aquifer tests performed by the Groundwater Department of the Alberta Research Council (from an unpublished report).
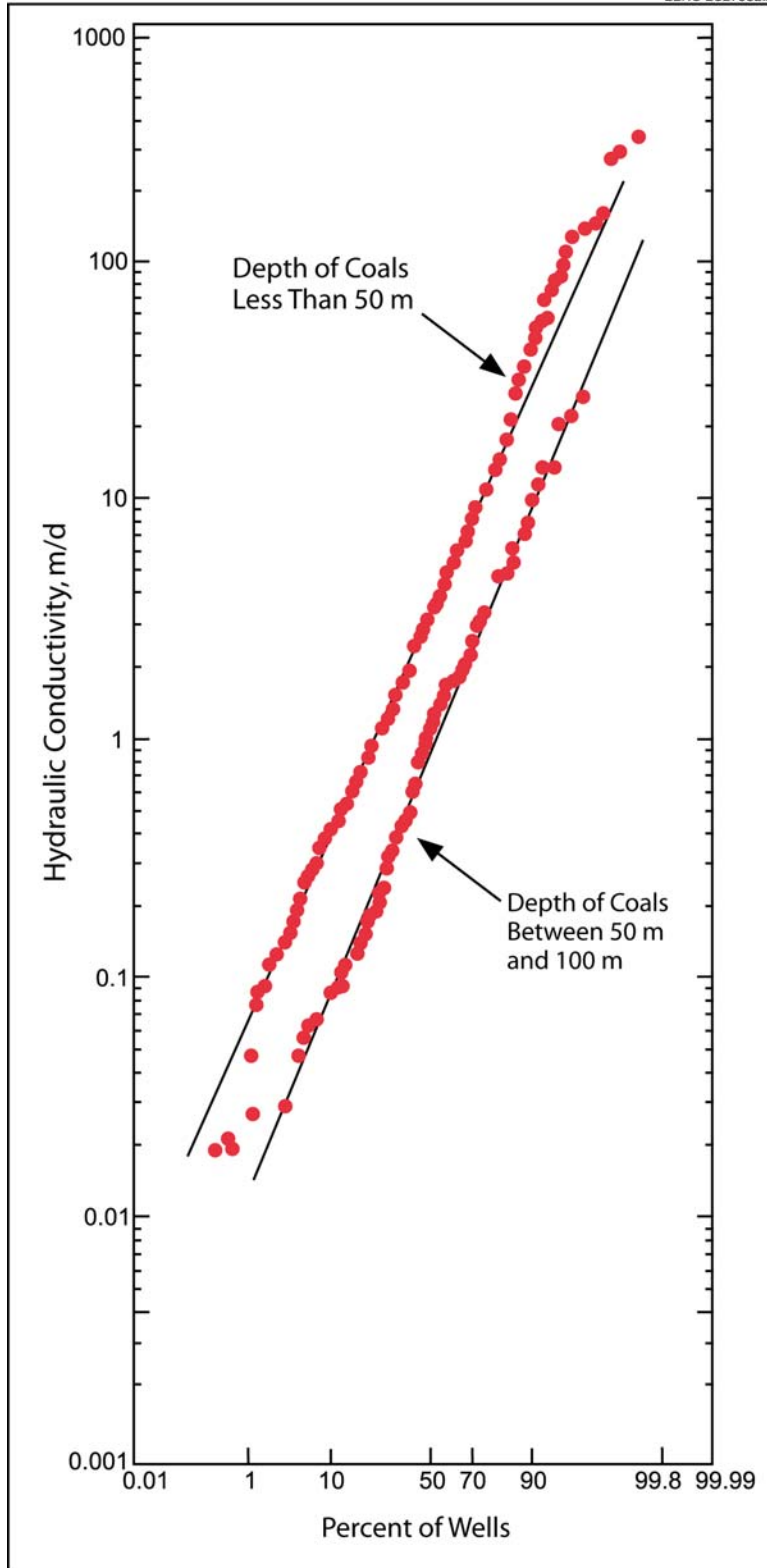
Figure 32. Frequency distribution of hydraulic conductivity for shallow coal aquifers in Alberta from tests performed by the Groundwater Department of the Alberta Research Council (from an unpublished report).

~80 m depth, then the following relationship would express better the variation of coal permeability with depth, as illustrated in Figure 33:

$$\ln(k) = 83.065 \times D^{-0.686} \tag{8}$$

The stress in the sedimentary rocks is taken by both the fluids saturating the pore space, where it is manifested as pressure, and by the rock matrix, including the coal. Given the stress tensorial nature, the minimum stress is the one that affects coal permeability by closing the cleats. Thus the stress and pressure regimes in the Upper Cretaceous–Tertiary coal-bearing strata in the Alberta Basin may indicate areas of enhanced coalbed permeability, or, vice-versa, areas of reduced permeability.

Gradients of vertical stress (weight of the overburden) vary from ~21 kPa/m in the northeast to ~24 kPa/m near the thrust and fold belt (Bell and Bachu, 2003), indicating increasing a westward compaction of the sedimentary column. Gradients of the minimum horizontal stress are mostly in the 16–18-kPa/m range (Bell and Bachu, 2003; Hawkes et al., 2005). Since the minimum horizontal stress increases with depth with a gradient of 16–18 kPa/m while hydrostatic pressure increases with a gradient of only ~10 kPa/m, it is obvious that, in strata that are hydrostatically pressured, the effective stress increases with depth with a gradient of 6–8 kPa/m (see Relation 4), thus closing coal cleats and decreasing permeability. If the stress increases with depth with a gradient pore space underpressured (see, for example, Figure 28) as a result of burial history and hydrodynamic regime, as is the case of both Horseshoe Canyon and Mannville strata, then the rocks take on, correspondingly, more (effective) stress, closing further coal fractures, and this could explain the rapid decrease in coal
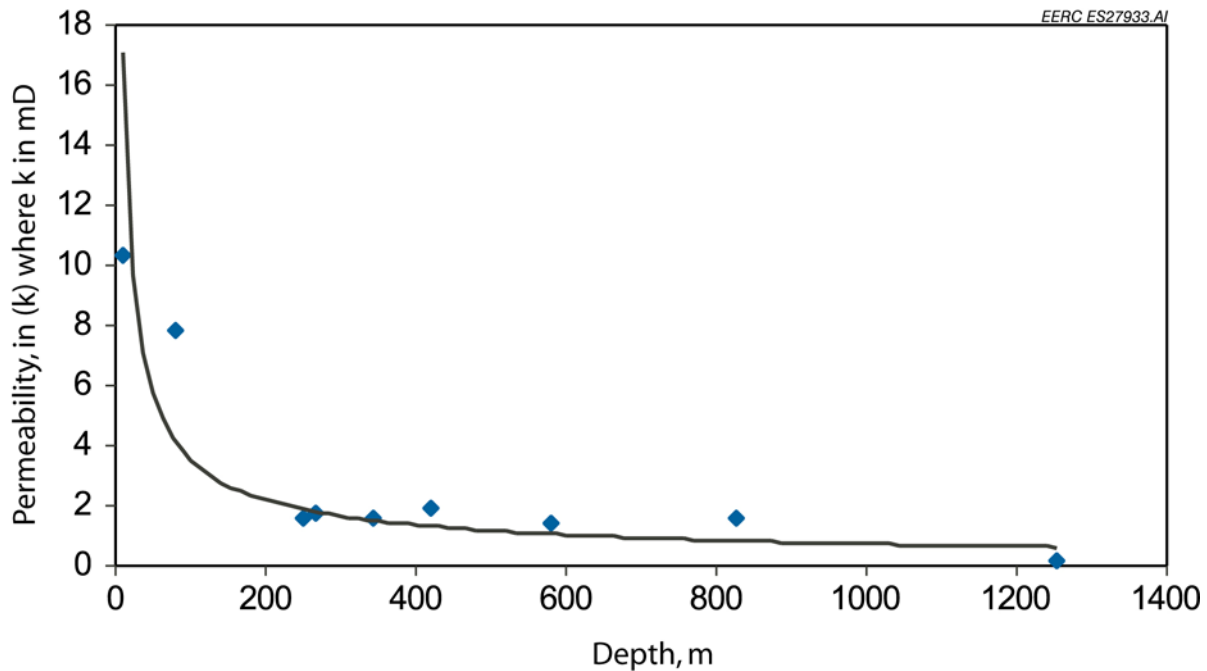

Figure 33. Estimated permeability variation with depth for coals in the Alberta plains.

permeability from shallow regions (less than 100 m deep) to deeper coals, as indicated by permeability data from these different populations. Thus low permeability is likely to be a problem with deep coal seams, because their permeability is generally less than that required for economical CBM production (Zuber et al., 1996) or CO_2 injection.

The maximum and minimum horizontal stress orientations have a direction generally perpendicular and parallel to the Rocky Mountain deformation front, respectively (Figure 34) (Bell and Bachu, 2003), as indicated also by the direction of face cleats identified in coal mines (Campbell, 1979). These cleats (fractures) will tend to be open and provide preferred flow paths for water and/or gas (methane or CO_2). The orientation of stress trajectories is an excellent indicator of the direction of coal cleat directions in a southwest–northeast direction and of similar permeability anisotropy in the coal bedding planes. As the vertical stresses are greater than the horizontal stresses, fractures, including those in coal seams, will generally be vertical and will propagate on a southwest–northeast axis along the direction of the maximum horizontal stress. At very shallow depths (<300 m), the vertical stress may be less than the minimum horizontal stress, in which case shallow fractures will be subhorizontal rather than vertical.

Geothermal Regime

Since CO_2 phase and adsorption onto the coal surface depend on temperature in addition to pressure, it is important to know the geothermal regime of the coals in order to estimate the CO_2 sequestration capacity of the Cretaceous–Tertiary coals in Alberta. The main basin-scale characteristic of the geothermal regime in Alberta is a northerly increase in average geothermal gradients from ~20°C/km in the south to >45°C/km in the north (Bachu and Burwash, 1991). Low geothermal gradients (<30°C/km) in the southern part of Alberta correspond to low radiogenic heat generation by old Archean rocks that underlie the sedimentary succession. A relatively small-scale heat anomaly southeast of Edmonton near the Alberta–Saskatchewan border correlates with a high-heat-generation anomaly (Bachu and Burwash, 1991).

Temperatures, *T*, at the base of the coal zones were determined on the basis of multiannual ground surface temperatures, distribution of average geothermal gradients in the area (Bachu and Burwash, 1991), and depth, according to the relation:

$$T = T_S + G \times D \tag{9}$$

where T_S is surface temperature, G is geothermal gradient, and D is depth.

Temperature distributions at the base of the coal zones of interest reflect primarily the depth of the coal zone, given the temperature increase with depth, but also areal variations in average geothermal gradients. This is most evident in the temperature distribution at the base of the Upper Mannville Coal Zone (Figure 35), where temperatures increase generally southwestward from ~16°C at the shallowest depth in the northeast to ~90°C in the southwest and ~125°C in the western deepest part near the Rocky Mountain deformation front. A geothermal anomaly in the
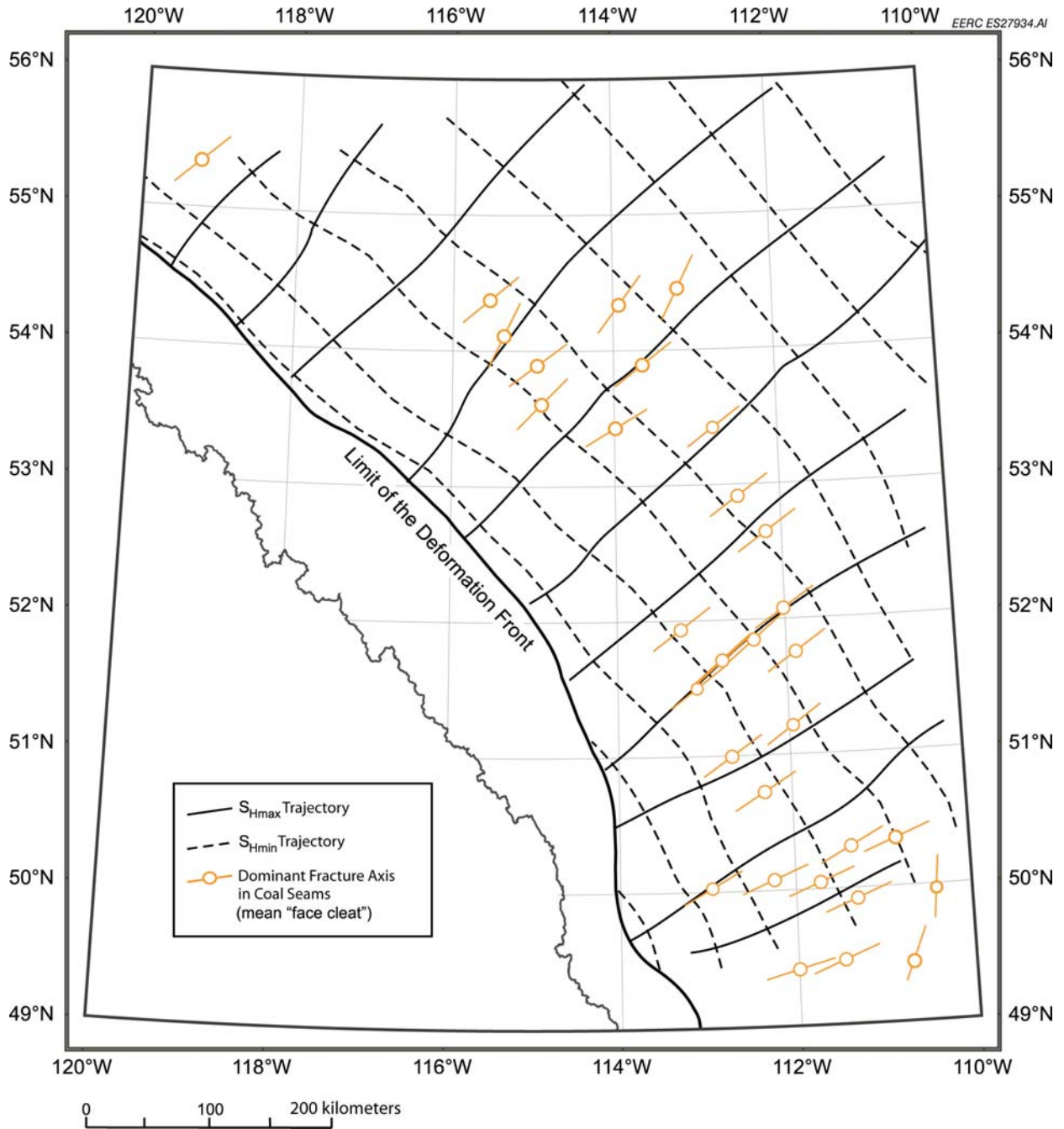
Figure 34. Stress trajectories in the coal-bearing Upper Cretaceous–Tertiary strata of the Alberta Basin.
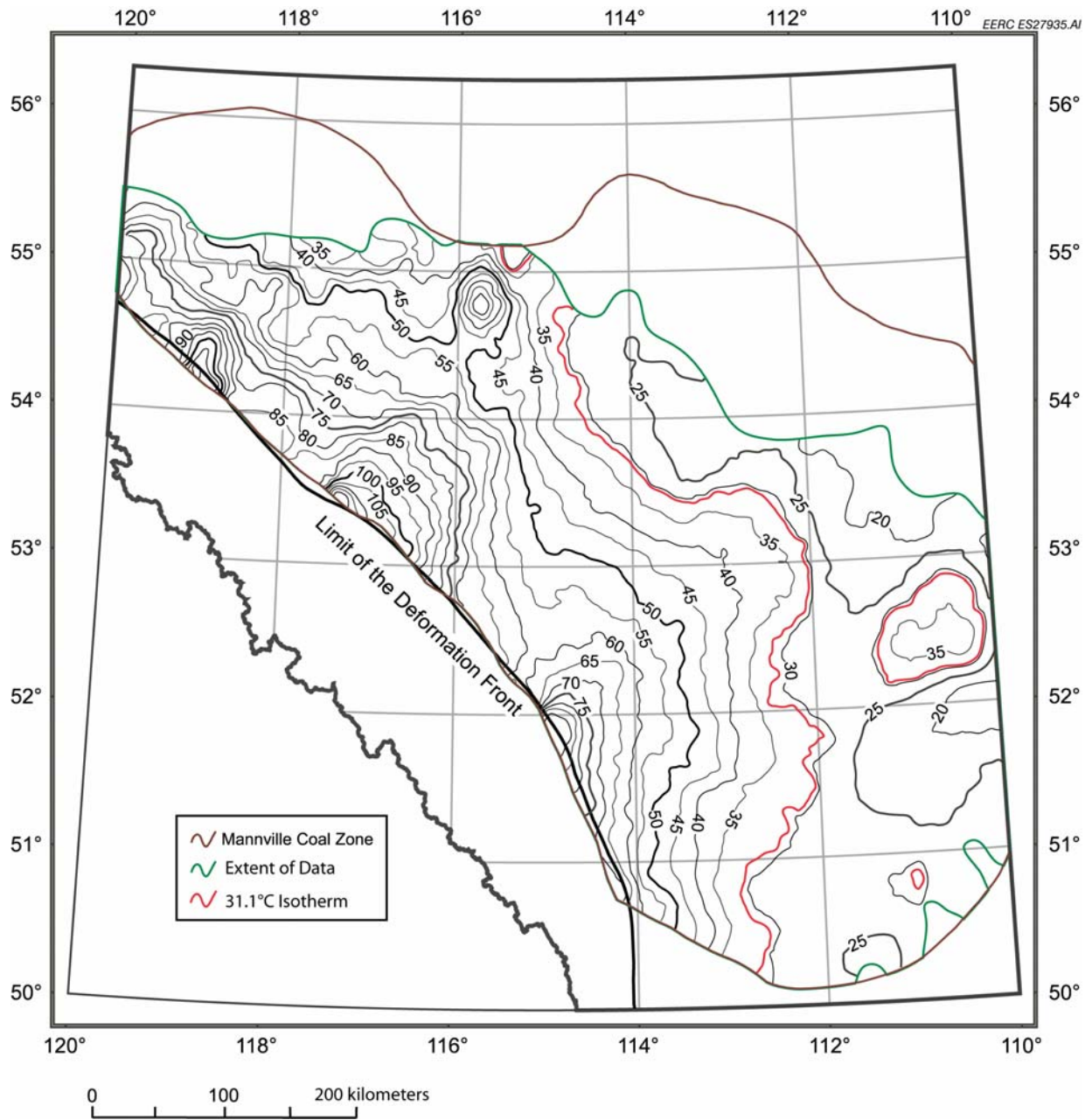
Figure 35. Temperature distribution at the base of the Upper Mannville Coal Zone.
Contour interval = 5°C.

east manifests itself with temperatures reaching >35°C (Figure 35). Temperatures are greater than 31.1°C (the CO_2 critical temperature) over most of the area of the Upper Mannville Coal Zone: more than the western half of the coal zone and in the area of the geothermal anomaly in the east.

Since the Drumheller and Ardley Coal Zones are present west of the geothermal anomaly near the Alberta–Saskatchewan border, the temperature distributions at the base of these coal zones reflect primarily only their depth. Temperatures at the base of the Drumheller Coal Zone vary from 8°C in the east at outcrop under Quaternary sediments to ~60°C in the west near the Rocky Mountain deformation front (Figure 36).

The thick coals in the Drumheller Coal Zone (Figure 18) are found at depths where temperatures are less than 31.1°C, the CO_2 critical temperature. Temperatures at the base of the Ardley Coal Zone barely reach 31.1°C in the west adjacent to the Rocky Mountain deformation front (Figure 37).

Temperatures and pressures are critical in establishing the in situ phase of the injected CO_2 and coal adsorption capacity, hence, CO_2 sequestration capacity, while coal permeability and stresses are essential for CO_2 injectivity and concurrent CBM producibility. The salinity of formation water is critical in establishing production and water disposal strategies, and it affects the economics of CO_2 sequestration and ECBMR operations.

CAPACITY FOR CO_2 SEQUESTRATION IN ALBERTA'S DEEP COALS

The first step in estimating the CO_2 sequestration capacity of the various coal zones in Alberta is the delineation of the respective region of potential interest for each coal zone.

CO_2 sequestration cannot be considered for shallow coals mainly for two reasons. These coal beds are water-saturated, have relatively high permeability, and constitute shallow groundwater aquifers, as shown by various hydraulic tests performed in the past (Figure 31); hence, they are a protected source of potable water. A search of the water wells in central and southern Alberta has shown that 98% of these wells are shallower than 300 m (Figure 38). Second, shallow coals in places in the Ardley and Drumheller Coal Zones now have an economic value, being mined at surface for power generation, or may have an economic value in the future, and the location of coalfields in the Alberta plains (Figure 7) attests to their present and/or future value. If CO_2 is sequestered in relatively shallow coals that may be mined in the future, it will be released back into the atmosphere at the time of mining and burning, thus annulling the effect of sequestration. Generally, coals at depths greater than 300 m are considered uneconomical, although underground coal mining is practiced in other parts of the globe, such as China, Ukraine, Germany, Poland, and South Africa; hence, deeper coals may be mined in Alberta at some time in the future if economic conditions warrant it. Since future economic conditions cannot be factored into current estimates of CO_2 sequestration potential, the 300-m depth was selected as the upper shallowest limit for CO_2 sequestration in coals in Alberta, i.e., any sequestration
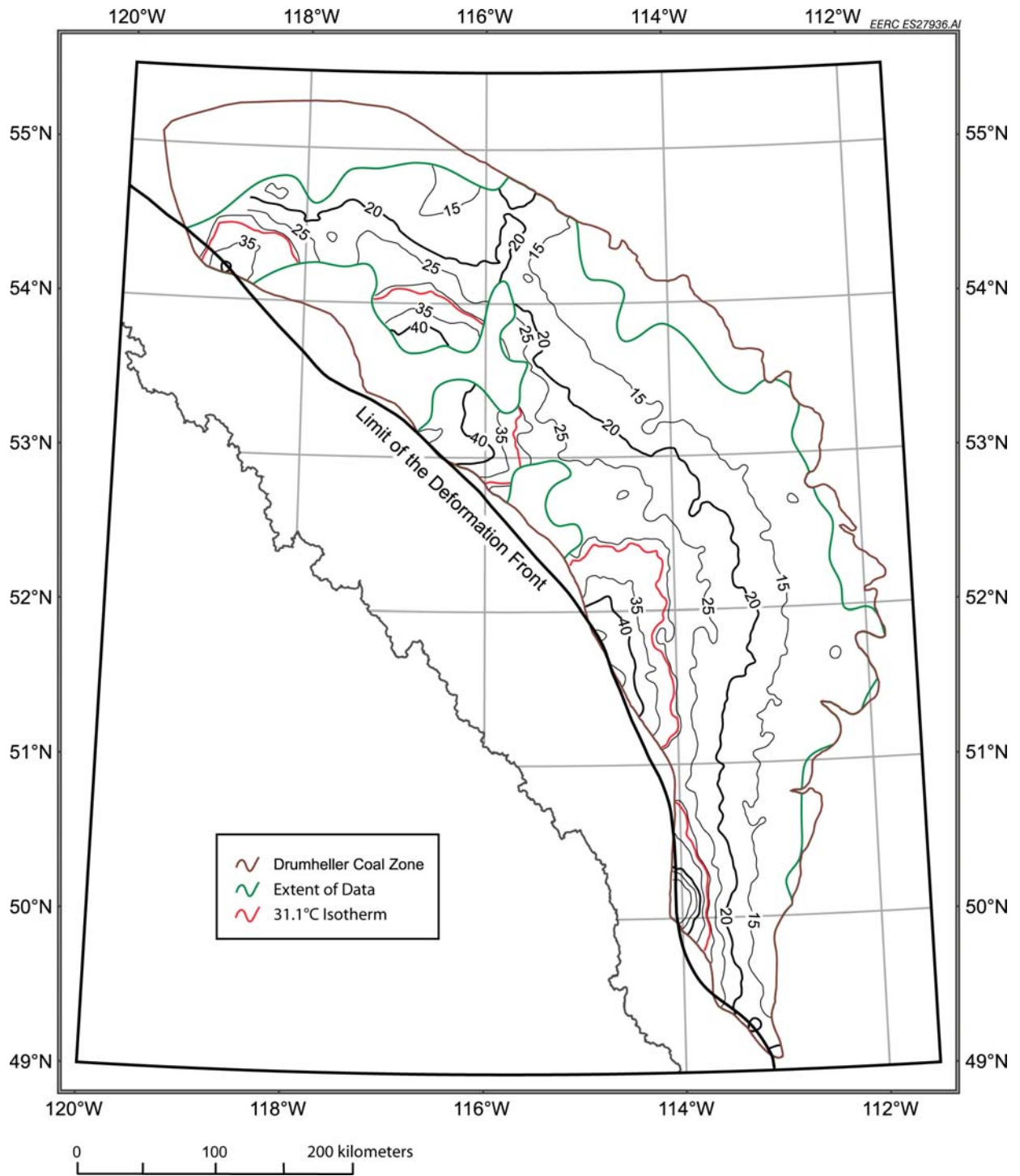
Figure 36. Temperature distribution at the base of the Drumheller Coal Zone. Contour interval = 5°C.
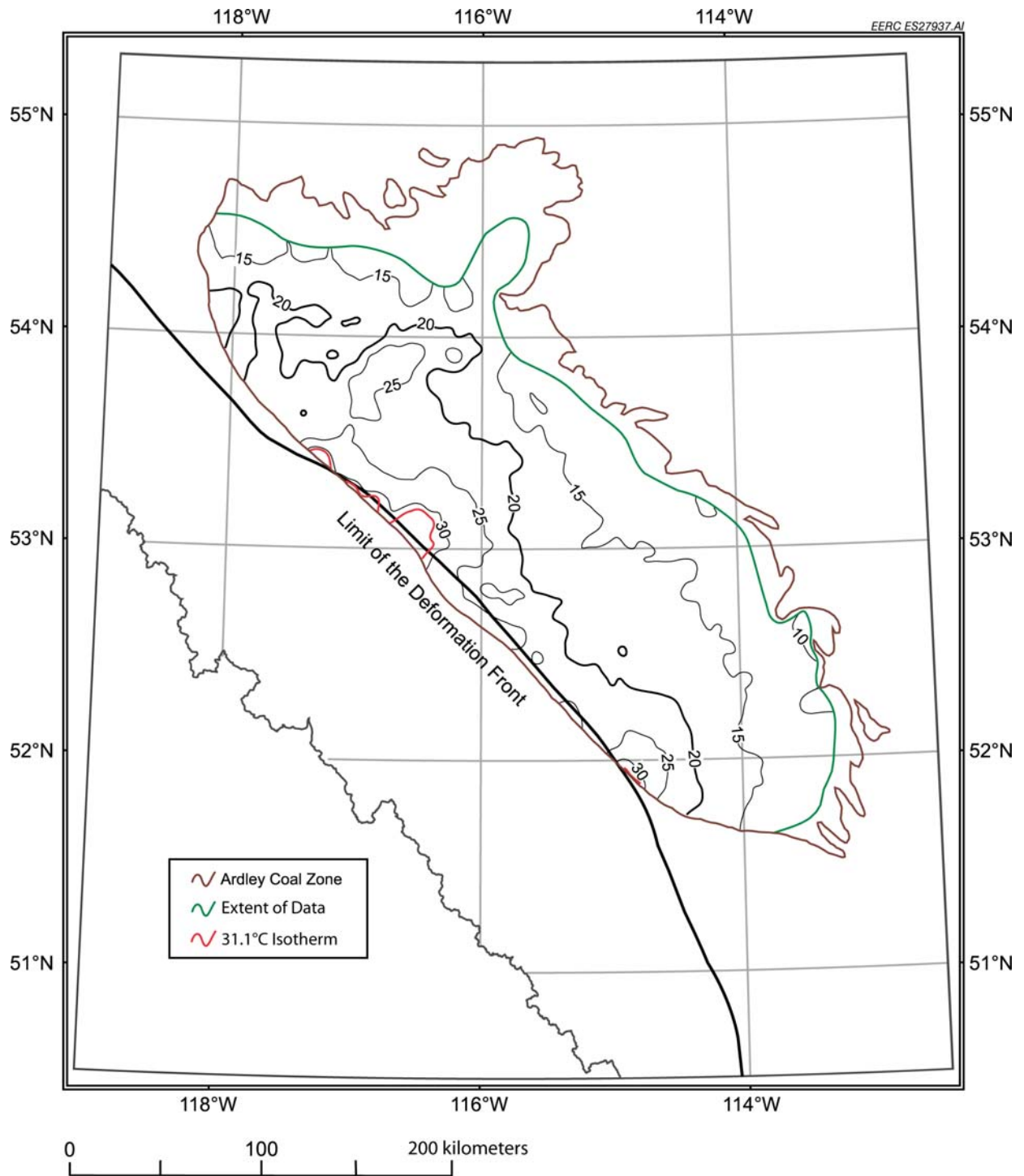
Figure 37. Temperature distribution at the base of the Ardley Coal Zone. Contour interval = 5°C.
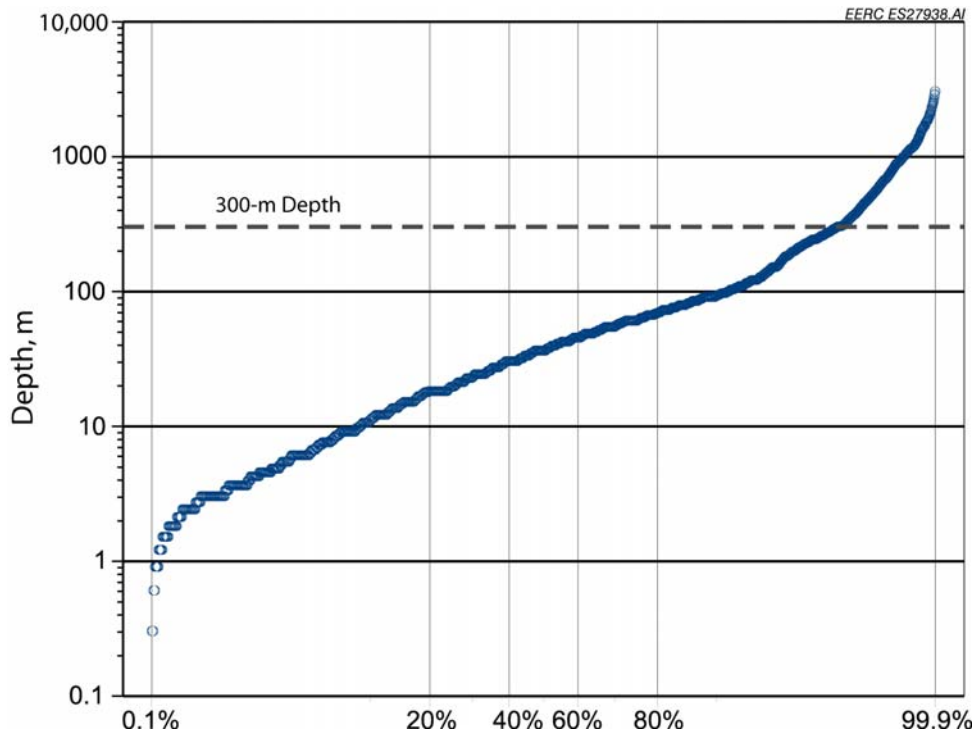
Figure 38. Frequency distribution of the depth of water wells in southern and central Alberta.

operation has to be at depths greater than 300 m to protect both groundwater resources and current and potential coal resources. Given the west-southwestward dip of the strata, including the coal beds, in the Alberta Basin, the 300-m depth limit represents the eastward boundary of the regions in the Drumheller and Ardley Coal Zones that should/could potentially be considered for CO_2 sequestration in these coal zones. These considerations do not apply to the Upper Mannville Coal Zone, which is found at depths greater than 300 m and is saturated with saline formation water (brackish to brine).

The deep, western limit of the region that could be considered for CO_2 sequestration in each coal zone has been determined on the basis of CO_2 phase at the respective in situ pressure and temperature conditions. As discussed previously, gaseous CO_2 is adsorbed onto the coal surface, but sequestration processes for liquid and supercritical CO_2 are not well understood, and it is possible that, under these conditions, coal is not a good sequestration medium for CO_2. The lack of technological success to date in sequestering CO_2 in coals also makes questionable consideration of coals deep enough such that CO_2 would be in either a liquid or supercritical phase. Thus the region deeper than 300 m where CO_2 will still be in the gas phase was considered in this study as the region with potential for CO_2 sequestration in coal zones in Alberta. The depth at which CO_2 would change phase to other than gas (i.e., liquid or supercritical) in the Upper Mannville, Drumheller, and Ardley Coal Zones was determined on the basis of pressure and temperature distributions and the CO_2 phase diagram (Figures 1, 26, 27, 29, 35–37, respectively). Given the general westward dip of the strata, including the coal beds, the location of this "CO_2 phase change" depth

represents the western, deep, limit of the region where CO_2 sequestration in respective coal zones would be possible with current knowledge and technology.

Although of the largest areal extent among the coal zones under consideration, the Upper Mannville Coal Zone has the smallest area potentially suitable for CO_2 sequestration, located in the northeast (Figure 39). Because of the depth of these coals, in situ conditions rapidly reach the temperature and pressure at which CO_2 changes phase to liquid or supercritical, such that only in the shallowest region CO_2 remains in the gaseous phase. Coal seams in this region have relatively low thickness (~5 m and less, Figure 14) and lowest coal rank and maturation for Upper Mannville coals. Furthermore, as depth, hence effective stress, and coal rank increase, the permeability of the deeper Mannville coals is expected to decrease significantly, such that the limitations on CO_2 storage in Mannville coals is due not only to the CO_2 phase but also to injectivity limitations.

As a result of the severe underpressuring in the Drumheller Coal Zone, the region suitable for CO_2 sequestration in these coals extends almost to their western limit at the Rocky Mountain deformation front, following an arcuate band approximately 50 to 80 km wide close to the Foothills (Figure 40). Unfortunately, the coal thickness in most of this region is low, mostly less than 5 m, while the thickest coals are located in the east (Figure 18), at depths around the 300-m limit. The region suitable for CO_2 sequestration in the Ardley Coal Zone forms a band approximately 40–50 km wide located at the center of the coal zone (Figure 41), widening to the northwest to ~100 km and where it reaches the coal zone western limit.

Two parameters are determinant in evaluating a CBM prospect or a CO_2 storage prospect: the total GIP (capacity) and reservoir deliverability (White et al., 2005). Thus, once the region of interest has been established for each coal zone, the next step is to estimate the CO_2 sequestration capacity in the respective region. In the case of a gas already adsorbed by the coal, like CBM, the initial gas in place (IGIP) is usually calculated with the relation (e.g., van Bergen et al., 2001; White et al., 2005):

$$IGIP = A \times h \times \tilde{n}_C \times G_C \times (1 - f_a - f_m) \tag{10}$$

where A and h are the area and effective thickness of the coal zone, respectively, $\tilde{n}_C$ is the bulk coal density, G_C is the coal gas content, and f_a and f_m are the ash and moisture weight fraction of the coal, respectively. The gas adsorption capacity of coal generally depends on pressure, temperature, and coal characteristics (Bustin and Clarkson, 1998), and their specific effect is currently a matter of debate. For a given temperature, the relation between pressure, P, and gas content, G_C, is generally assumed to follow a pressure-dependent Langmuir isotherm of the form:

$$G_C = V_L \times \frac{P}{P + P_L} \tag{11}$$

where V_L and P_L are Langmuir volume and pressure, respectively. The Langmuir volume, V_L, represents the maximum gas adsorption capacity of a particular coal at the given temperature. In the case of CO_2 sequestration in coal beds, the basic
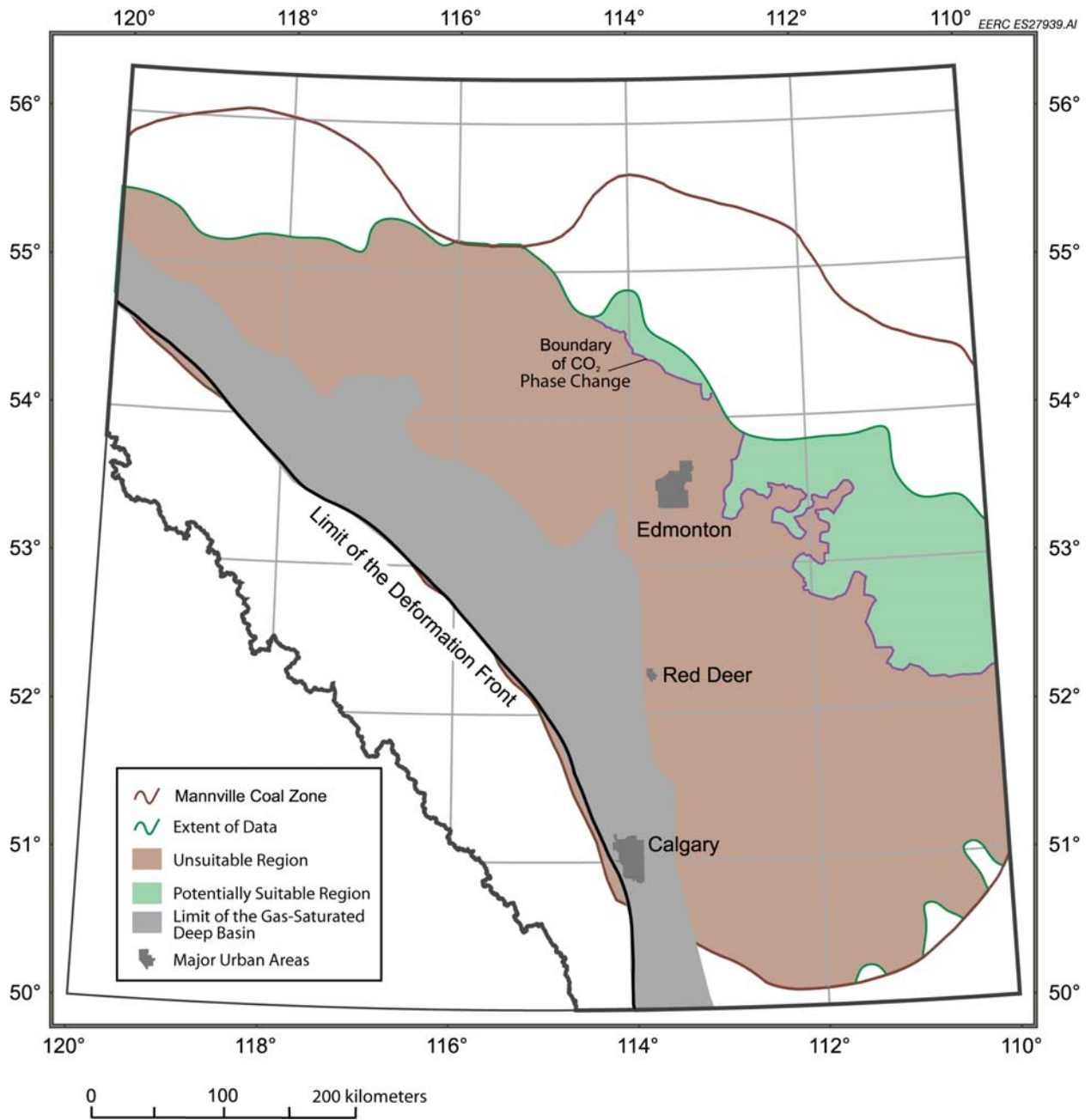
Figure 39. Region potentially suitable for CO_2 sequestration in coals of the Upper Mannville Coal Zone.
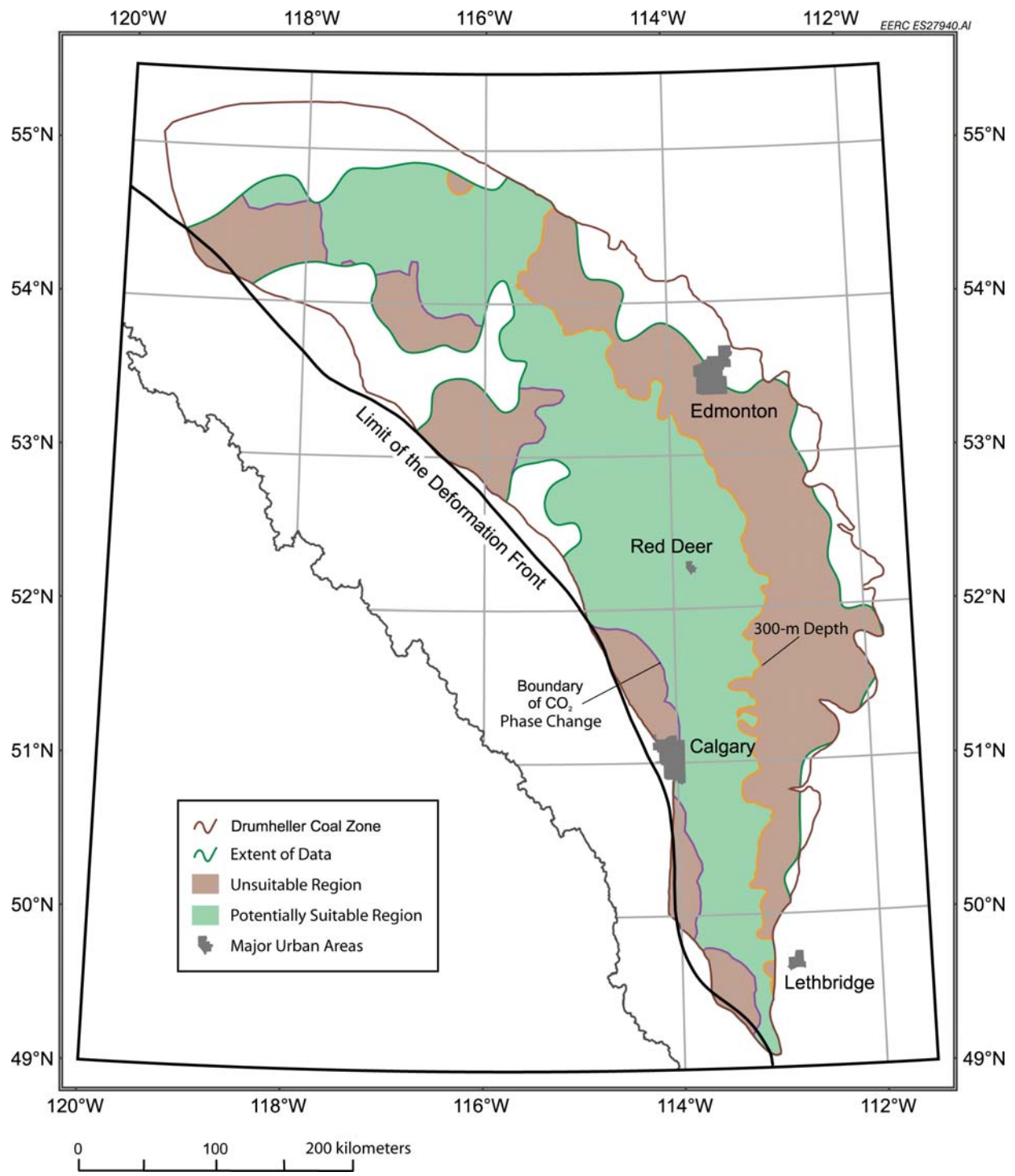
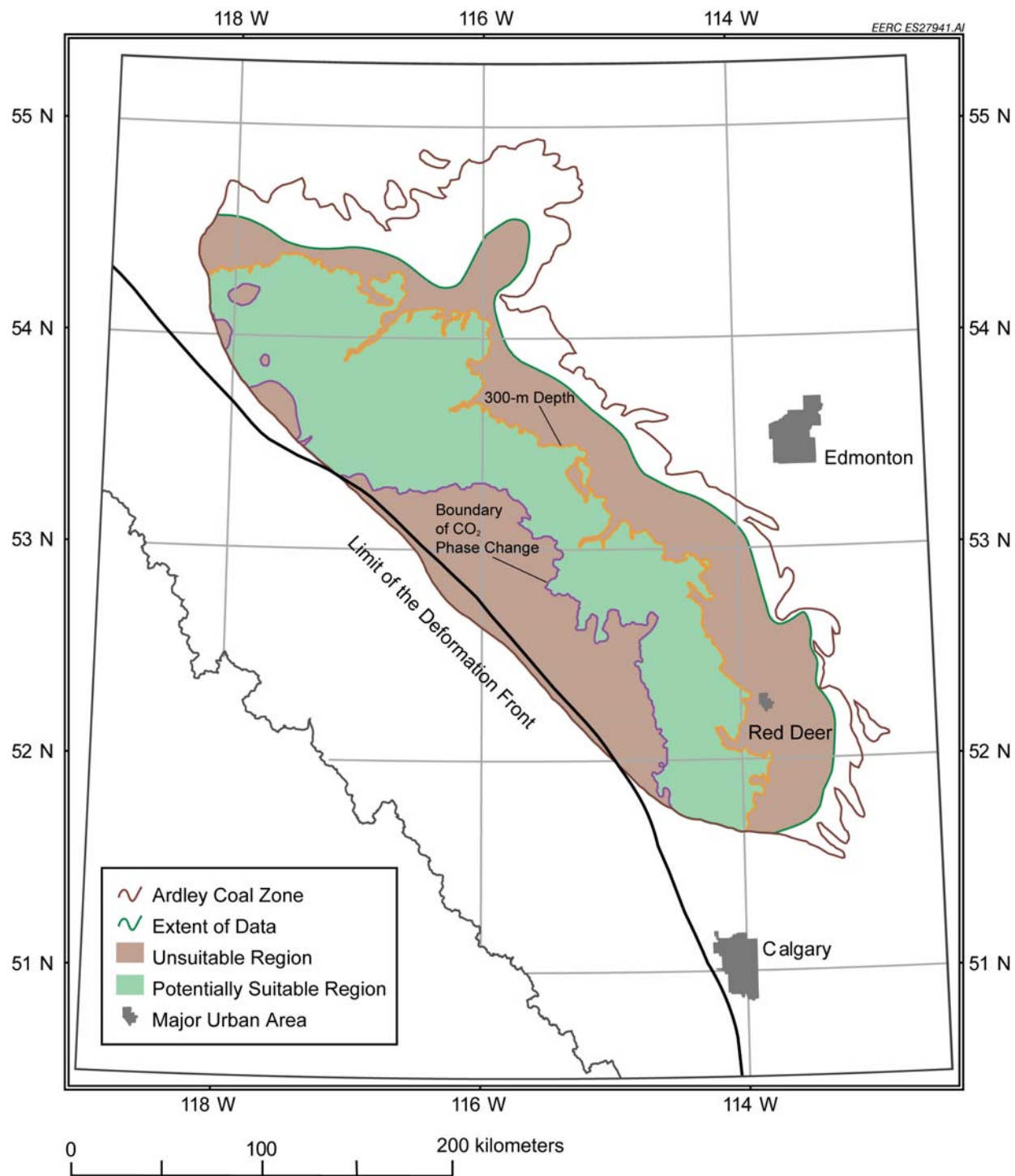Figure 40. Region potentially suitable for CO_2 sequestration in the coals of the Drumheller Coal Zone.

Figure 41. Region potentially suitable for CO_2 sequestration in coals of the Ardley Coal Zone.

assumption is that CO_2 will replace methane and other hydrocarbon gases present in the coal as a result of coal's higher affinity for CO_2 than for these gases (see Figure 2). Thus Relation 10 can be used in a reverse mode to estimate the maximum theoretical capacity for CO_2 sequestration of a coal bed if CO_2 Langmuir isotherms are known.

The Langmuir isotherm expressed by Equation 11 displays an increase in adsorption capacity with increasing pressure as the gas content, G_C, tends asymptotically towards V_L with increasing pressure, P (e.g., Figure 2). This behavior reflects monolayer adsorption on a surface, where the maximum represents the state of a completely covered surface that cannot adsorb anymore gas molecules. On the other hand, the gas adsorption capacity decreases with increasing temperature (Bustin and Clarkson, 1998) and, since both pressure and temperature increase with depth, after a certain depth the gas adsorption capacity decreases. Coal composition, rank, ash content, and moisture content affect the coal adsorption capacity in a complex way that has not been quantified to date. Generally, CO_2 adsorption capacity has a weak correlation with rank, increasing at high rank, but data suggest that adsorption is higher for low- (lignite and subbituminous) and high-rank coals than for medium-rank (bituminous) coals (Ryan and Richardson, 2004). The presence of nonorganic material (ash) and water in the coal reduces its adsorption capacity (White et al., 2005), as can be seen in Table 3 in the case of CO_2 adsorption isotherms for coal samples from the Ardley, Drumheller, and Upper Mannville Coal Zones (compare "as received" values with "dry, ash-free" values). Figure 42 shows the location of these coal samples, and Figure 43 shows representative adsorption isotherms for CO_2 for coal samples from these three coal zones.

The theoretical, ultimate potential for CO_2 sequestration in the Upper Mannville, Drumheller, and Ardley coals inside the respective region of applicability was calculated using Relations 10 and 11 and the adsorption capacity data for dry, ash-free coal samples from wells inside this region (Table 3), considering a coal density value of $\tilde{n}_C$ =1.4 t/m³ and an average moisture and ash content according to the measurements in Table 3. To express the CO_2 sequestration capacity in mass rather than volume of CO_2, the results have to be multiplied by CO_2 density at standard conditions of 1.873 kg/m³.

The theoretical CO_2 sequestration capacity in the Upper Mannville Coal Zone varies between 21 ktCO$_2$/km² and 440 ktCO$_2$/km² (Figure 44) if the adsorption isotherm with higher Langmuir volume is used (Test 14 in Table 3). If the lower isotherm is used in calculations (Test 13 in Table 3), then the range drops slightly to 20 ktCO$_2$/km² and 417 ktCO$_2$/km². Although the difference in Langmuir volume between the two samples is quite large (Table 3), one should remember that this is the value that is reached asymptotically at very high pressure. The differences are much reduced in the range of "relatively low" pressures characteristic of the region suitable for CO_2 sequestration in Mannville coal beds. The theoretical CO_2 sequestration capacity in the Drumheller Coal Zone varies between 7 ktCO$_2$/km² and 860 ktCO$_2$/km² (Figure 45), the wider range of variability than for the Upper Mannville Coal Zone being due to a corresponding wider range of variability in coal thickness. However, the greatest CO_2 sequestration potential is found for Ardley coals, where the storage capacity varies from 21 ktCO$_2$/km² in the areas of thin coals to 1260 ktCO$_2$/km² in the areas of thick coals with high adsorption capacity (Figure 46).

Table 3. Location and CO_2 Langmuir Isotherm Characteristics of Coal Samples from Coal Zones in Alberta: Ardley (Samples 1–8), Drumheller (Samples 9–11) and Upper Mannville (Samples 12–14) (Langmuir volume units are in cc/g, or m^3/t)

Sample No.	Well Location	Depth, m	Temp., °C	Ash, wt%	Moisture, wt%	Langmuir Pressure, MPa	Langmuir Volume, as received	Langmuir Volume, dry, ash free
1	8-16-45-7 W5Mer	412.8	26.0	10.0	11.01	3.05	36.20	45.82
2	8-16-45-7 W5Mer	411.6	37.0	21.0	8.65	3.55	32.84	46.69
3	8-16-45-7 W5Mer	405.8	27.0	18.6	9.40	3.66	35.71	49.61
4	6-23-52-5 W5Mer	91.2	10.0	9.9	19.00	2.13	24.84	34.92
5	13-2-37-28W4Mer	262.0	15.0	42.7	15.64	2.14	18.00	43.18
6	9-34-38-28 W4Mer	287.0	20.0	7.4	13.46	3.59	36.81	46.53
7	11-1-56-19W5Mer	592.5	19.6	5.6	13.94	2.12	30.55	37.97
8	6-9-36-25 W4Mer	236.0	12.0	6.7	14.59	2.83	37.20	47.26
9	8-22-47-26W4Mer	390.0	n.a.	16.0	10.26	3.41	39.52	54.24
10	16-32-34-21W4Mer	334.5	17.5	7.6	18.36	2.80	34.02	49.95
11	9-10-36-19W4Mer	232.0	18.5	11.24	20.88	3.84	32.20	47.50
12	4-23-36-20W4Mer	1252.0	n.a	n.a	n.a	1.90	n.a	31.02
13	9-1-36-19W4Mer	1290.0	35.5	19.72	7.83	2.95	27.20	37.60
14	6-14-44-15W4Mer	902.0	36.1	4.46	13.96	4.94	40.02	52.55

The distributions of theoretical CO_2 sequestration capacity in these coal zones mimic the respective coal distributions(Figures 14, 18, and 21), which is an entirely expected result. The total theoretical CO_2 sequestration capacity in these coals is on the order of 20 $GtCO_2$, with 45% of this capacity in Ardley coals. These values represent the ultimate sequestration capacity limit that would be attained if all the coals will be accessed by CO_2 and will adsorb CO_2 to 100% saturation. It is obvious that, in reality, these conditions will not be met, hence, the need to reduce the theoretical sequestration potential to more realistic estimates. This would be similar to the reduction of IGIP to producible gas in place (PGIP) in the case of gas production from coals.
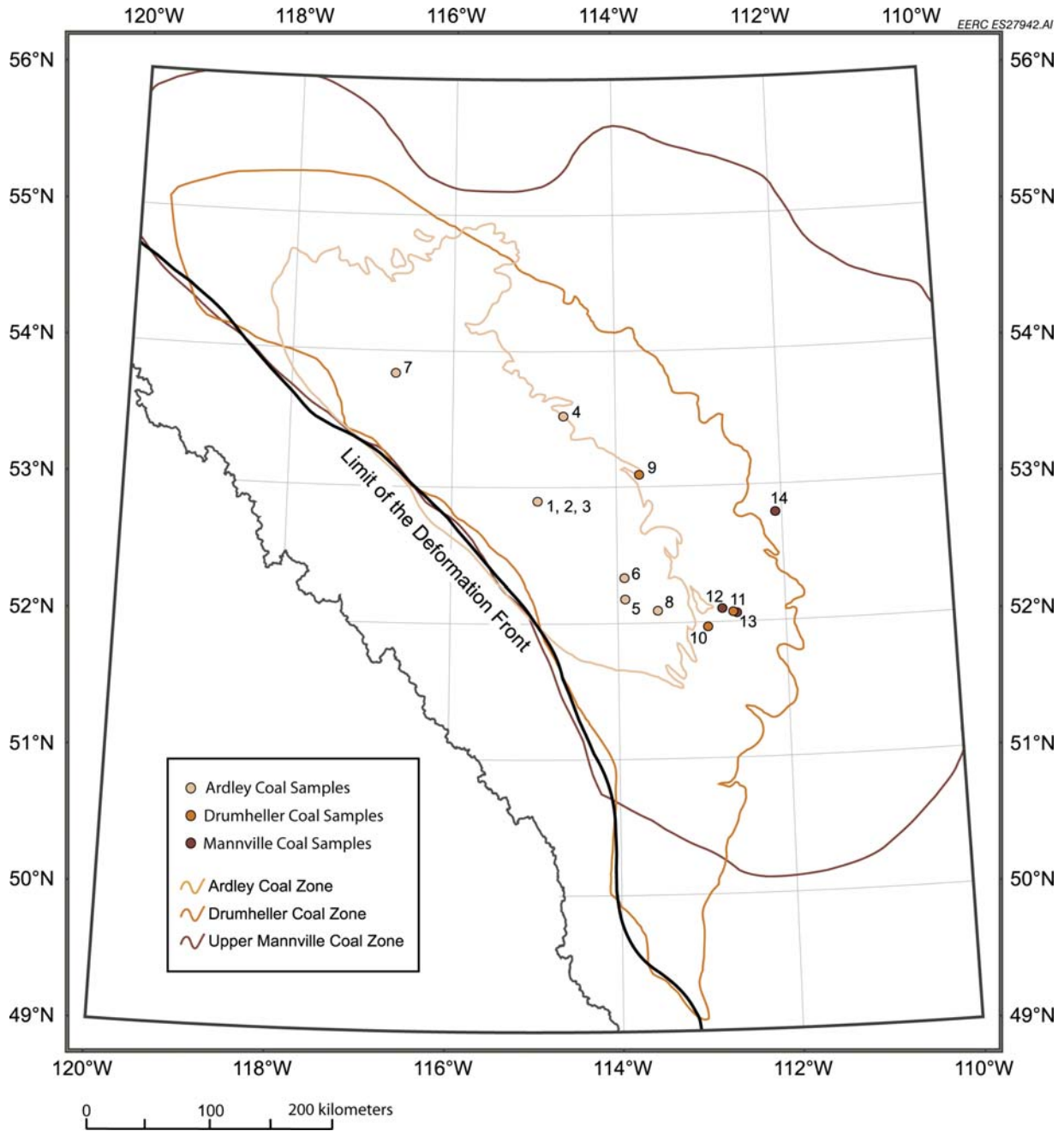
Figure 42. Location of coal samples for which Langmuir adsorption isotherms have been measured for both methane and CO_2.
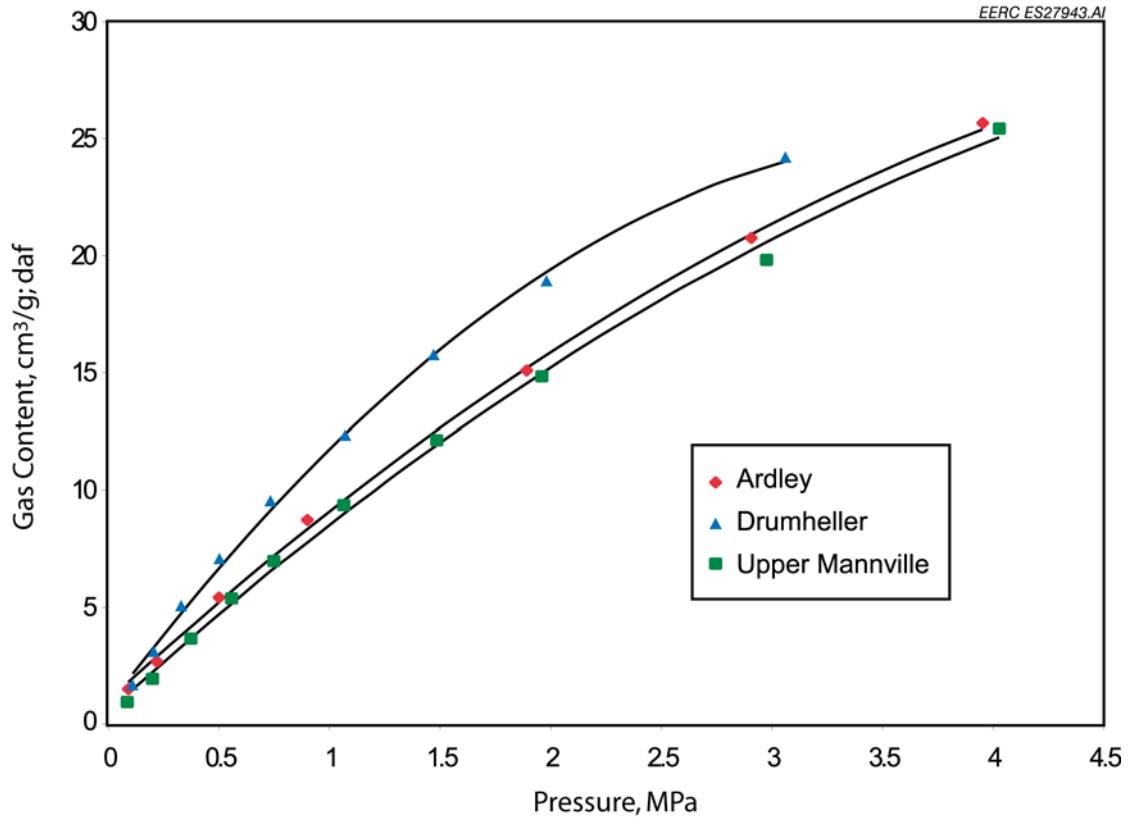
Figure 43. Typical adsorption isotherm for methane and CO_2 for coals from Upper Mannville, Drumheller, and Ardley Coal Zones.

PGIP represents only a fraction of the IGIP and can be estimated according to (van Bergen et al., 2001):

$$PGIP = R_f \times C \times IGIP \tag{12}$$

where R_f is the recovery factor and C is the completion factor and together they express the reservoir gas deliverability. The completion factor C represents an estimate of that part of the net cumulative coal thickness within the drilled coal zone that will contribute to gas production, it strongly depends on the individual thickness of the separate coal seams and on the distance between them, and is lower for thin coal seams than for thick ones. The recovery factor, R_f, represents the fraction of gas that can be produced from the coal seams. In conventional CBM production, R_f strongly depends on the pressure drop that can be realized by pumping out large volumes of water (coal dewatering) and ranges between 20% and 60% (van Bergen et al., 2001). Given the higher coal affinity for CO_2 than for methane, it is assumed that the recovery factor will increase significantly in CO_2 ECBMR operations, theoretically approaching 100%. Finally, the coal adsorption capacity for any given gas, in this case CO_2, is affected by the presence of other gases, usually being reduced. Although the normal assumption is that methane and other hydrocarbon gases present in the coal will be replaced by CO_2, a reduction in the adsorption capacity is nevertheless to be expected.

Figure 44. Areal distribution of theoretical capacity for CO_2 sequestration in coals of the Upper Mannville Coal Zone. Contour interval = 100 $ktCO_2/km^2$.
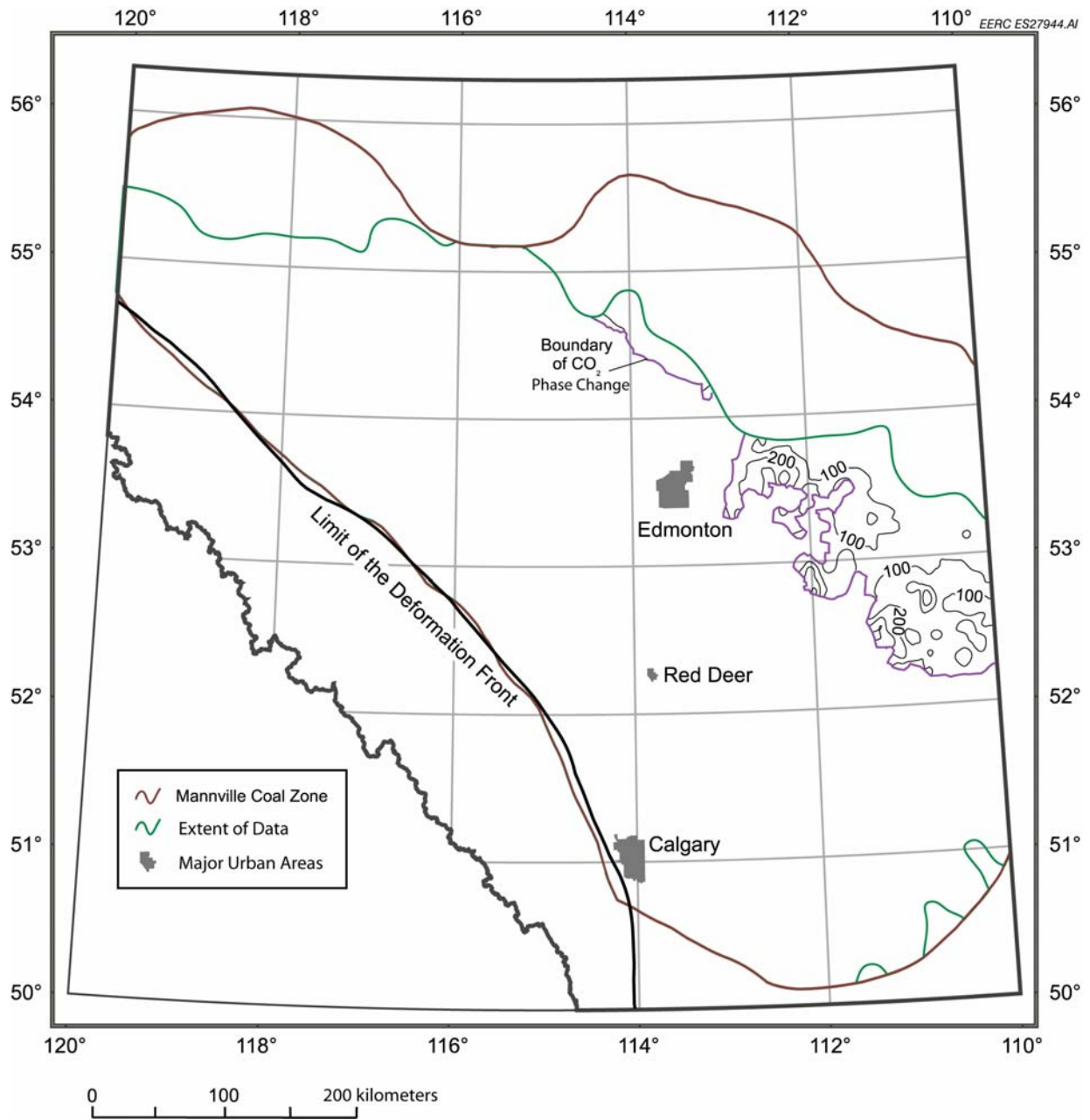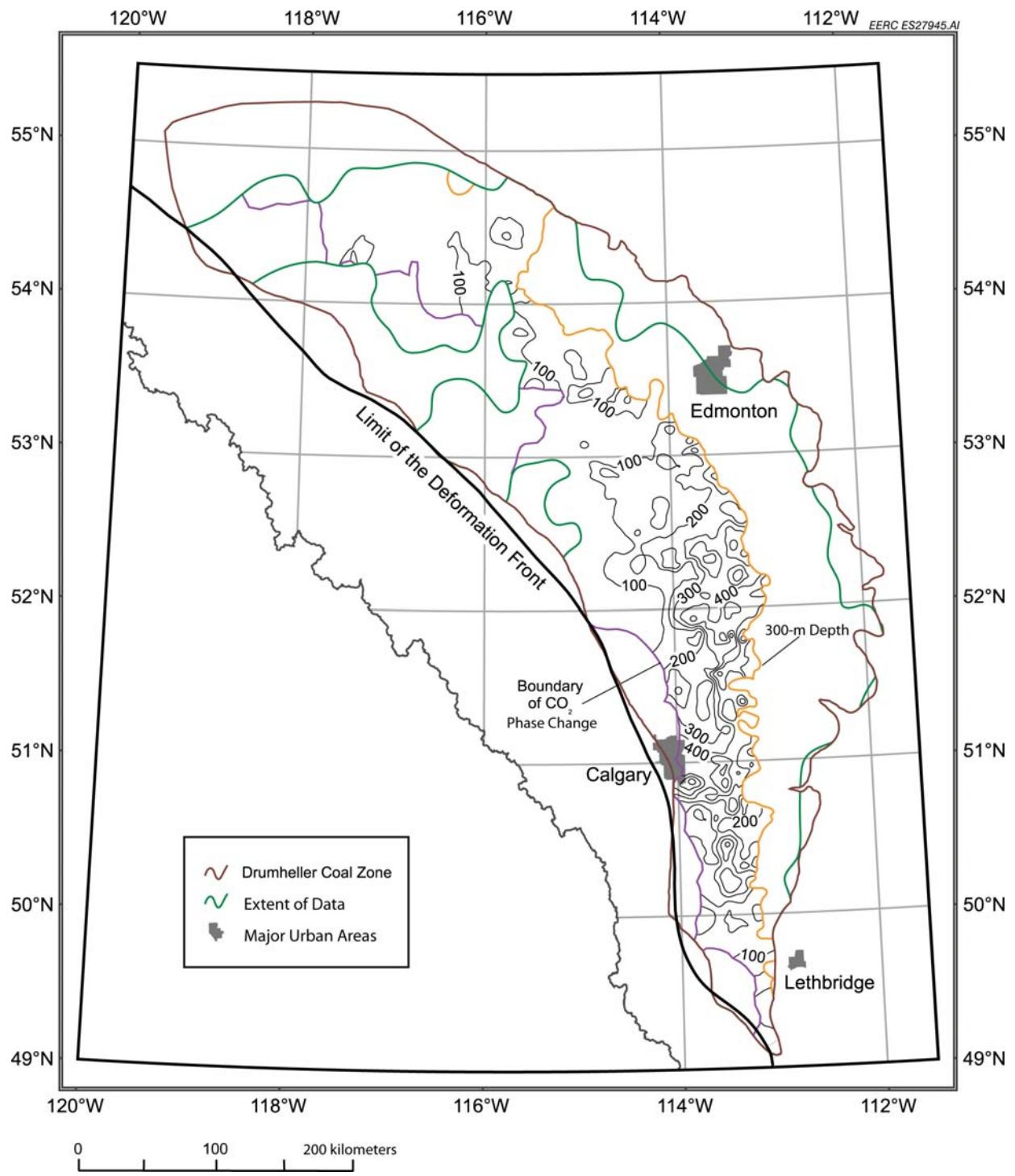
Figure 45. Areal distribution of theoretical capacity for CO_2 sequestration in coals of the Drumheller Coal Zone. Contour interval = 100 $ktCO_2/km^2$.
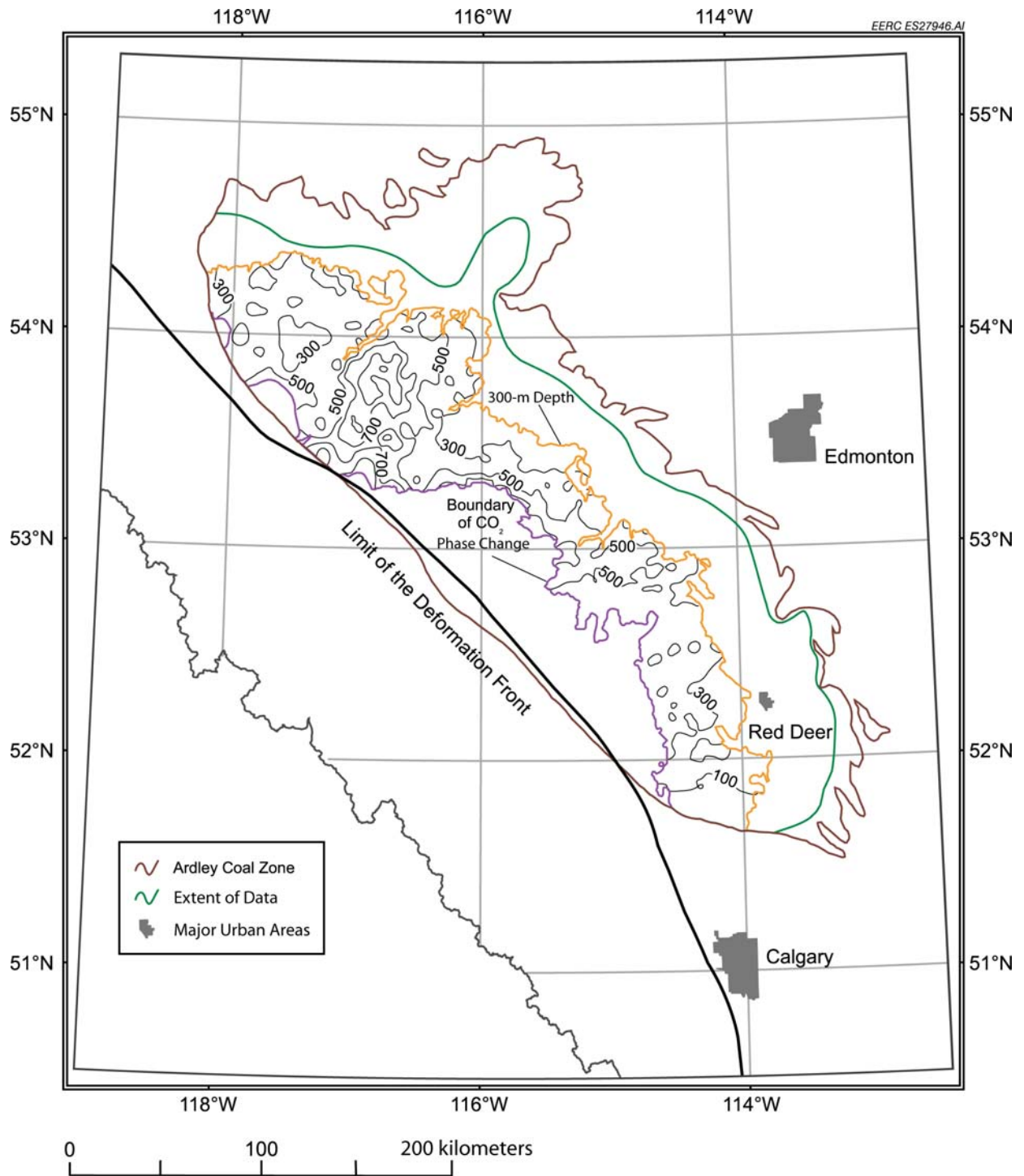
Figure 46. Areal distribution of theoretical capacity for CO_2 sequestration in coals of the Ardley Coal Zone. Contour interval = 200 $ktCO_2/km^2$.

In the current calculations, a completion factor of 40% and a recovery factor of 80% are assumed (i.e., only 40% of the coal mass will be reached by CO_2, both vertically and areally, and the presence of other, not produced gases reduces the CO_2 sequestration capacity by another 20%). These numbers, while realistic, are somewhat arbitrary. As experience is gained with these operations, these numbers can be easily modified and applied anew to improve the capacity estimates and identify the regions with the highest potential. Applying these factors leads to a reduction in the theoretical CO_2 sequestration capacity by close to 70% to an effective total capacity of 6.4 $GtCO_2$ for the three coal zones in the respective areas of applicability. The CO_2 sequestration capacity varies between 6.8 $ktCO_2/km^2$ and ~141 $ktCO_2/km^2$ for the Upper Mannville Coal Zone (Figure 47), 2.3 $ktCO_2/km^2$ and 275 $ktCO_2/km^2$ for the Drumheller Coal Zone (Figure 48), and 6.8 $ktCO_2/km^2$ and ~400 $ktCO_2/km^2$ for the Ardley Coal Zone (Figure 49).

The effective CO_2 sequestration capacity in these coal zones in Alberta is comparatively much smaller than the CBM potential identified to date. This is due to two factors. First, the CBM potential in the Alberta Basin (Table 1; McLeod et al., 2000; Beaton et al., 2002; Beaton, 2003) was estimated for each coal zone over the entire area where that respective coal zone is present. In contrast, the CO_2 sequestration capacity was calculated for each coal zone in a correspondingly smaller area, sometimes quite significantly, delineated by depths greater than 300 m and shallower than the depth where CO_2 would change phase from gaseous to liquid or supercritical as a result of increased pressures and temperatures. Second, unlike the CO_2 sequestration capacity, the CBM potential was estimated using only Relations 10 and 11, without consideration for recovery and completion (Relation 12).

It is highly unlikely that all the effective CO_2 sequestration capacity in Alberta's coal zones will be utilized because it will be uneconomical to build the necessary infrastructure (pipelines, compressors, and a high density of injection wells) for areas with low sequestration capacity per unit surface. Considering that it is economical to develop the necessary infrastructure only for areas with CO_2 sequestration capacity greater than 200 $ktCO_2/km^2$, then the CO_2 sequestration capacity in coal beds in Alberta is greatly reduced further to a practical capacity of only ~1 $GtCO_2$. This sequestration capacity is distributed mainly in the Whitecourt and Pembina areas of west-central Alberta and scattered in small areas to the northwest and east-southeast of Calgary in the Three Hills and Carseland regions (Figure 50).

It appears that there are no suitable target areas with high CO_2 sequestration capacity in the Mannville Coal Zone and, generally, the Mannville Coal Zone is not a good candidate for CO_2 sequestration for the following reasons:

- By and large, the Mannville coals are too deep and likely have very low permeability, requiring fracturing for CO_2 injection.

- The formation water that saturates the Mannville coals is very saline, thus requiring treatment when produced with methane, and/or deep injection for disposal.

Figure 47. Areal distribution of effective capacity for CO_2 sequestration in coals of the Upper Mannville Coal Zone. Contour interval = 50 $ktCO_2/km^2$.

Figure 48. Areal distribution of effective capacity for CO_2 sequestration in coals of the Drumheller Coal Zone. Contour interval = 50 ktCO_2/km^2.

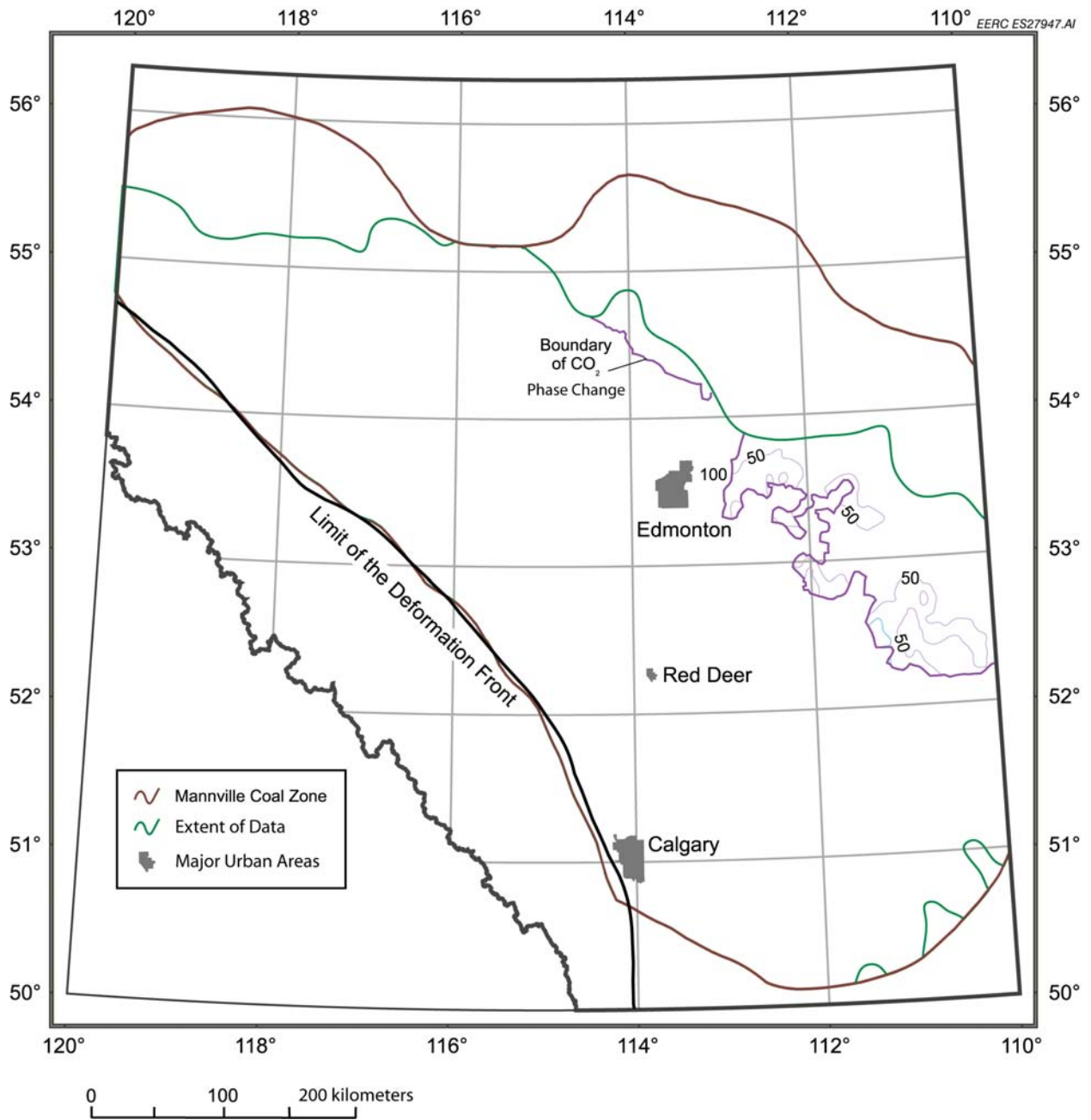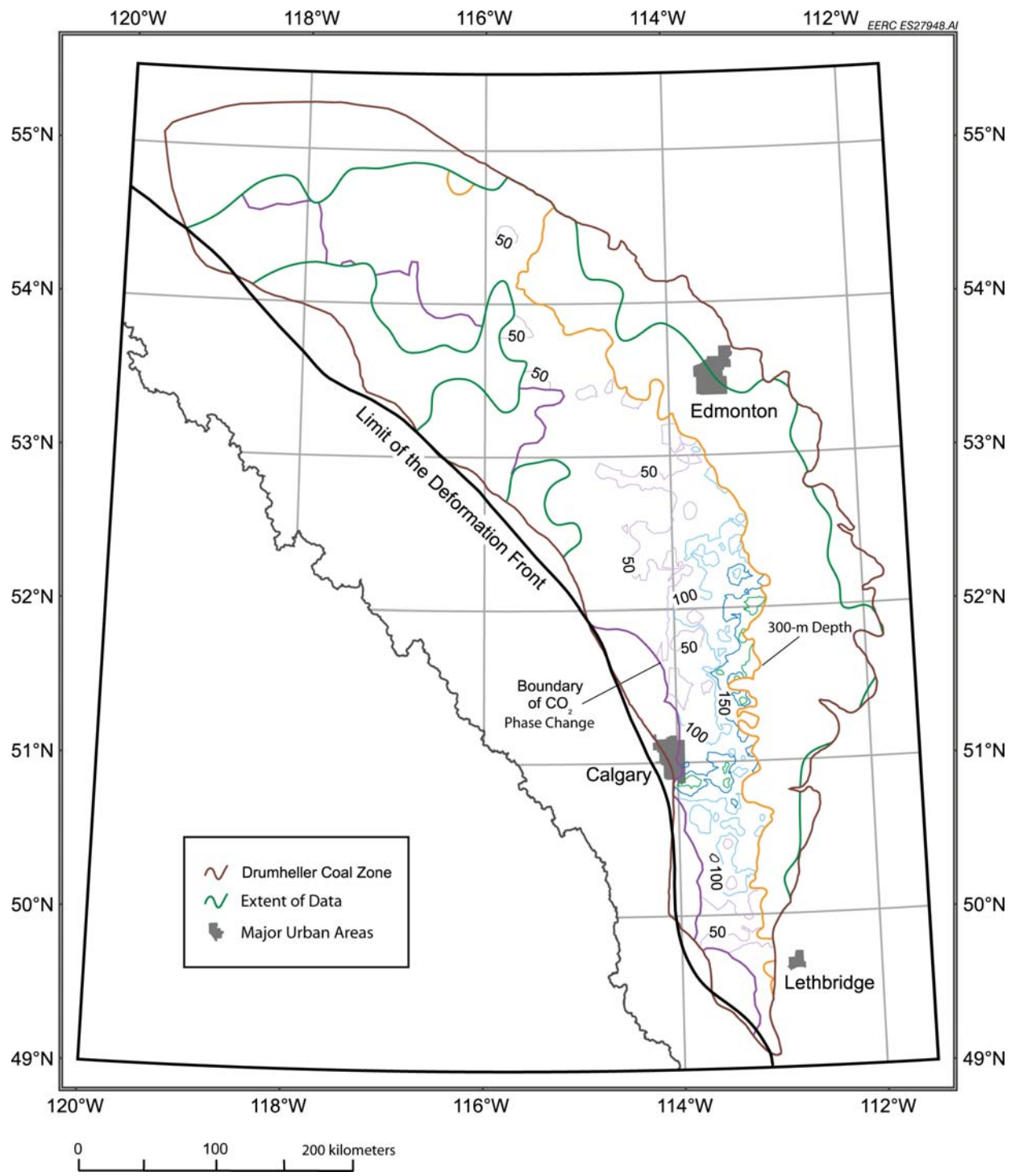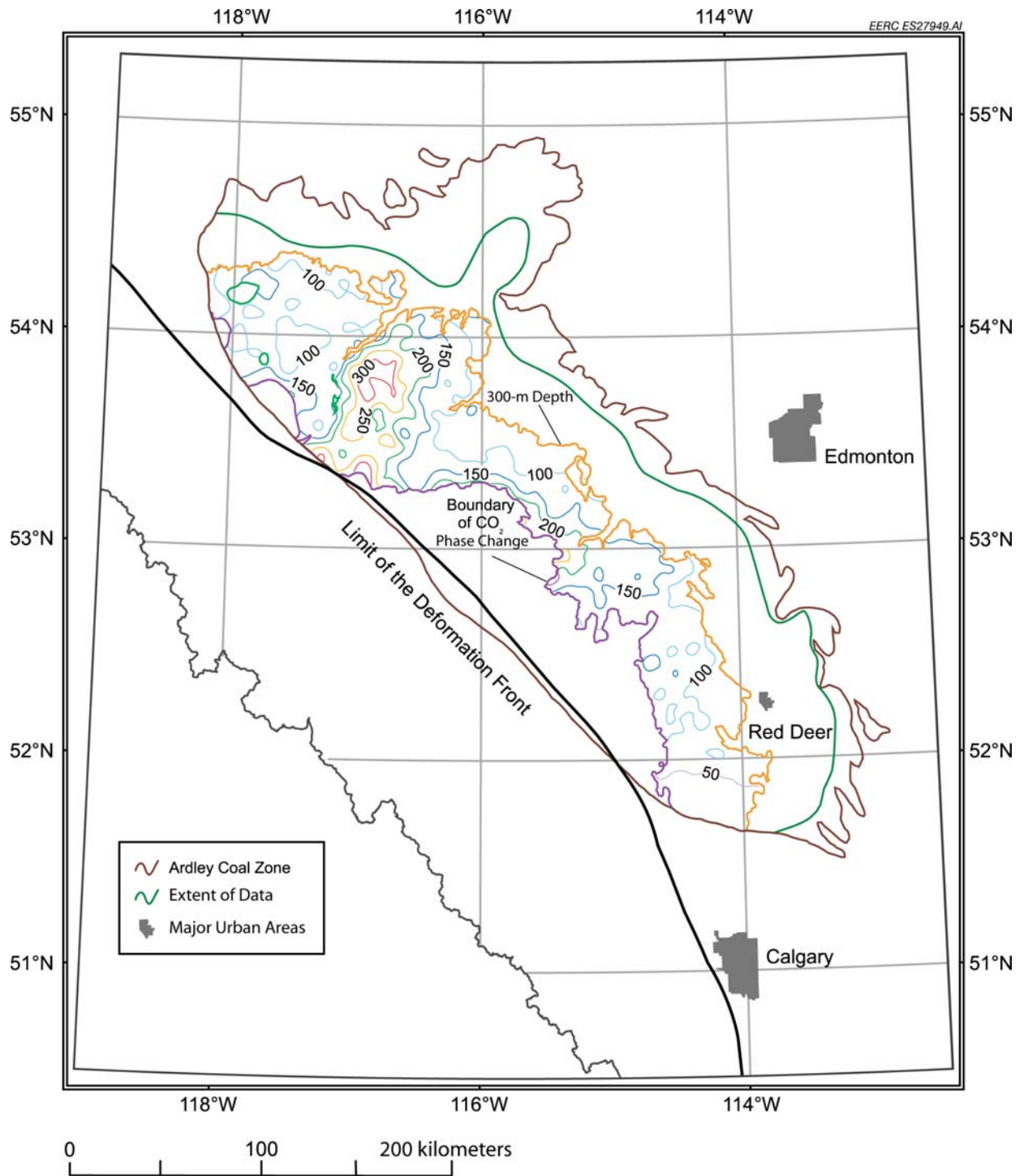Figure 49. Areal distribution of effective capacity for CO_2 sequestration in coals of the Ardley Coal Zone. Contour interval = 50 ktCO_2/km^2.
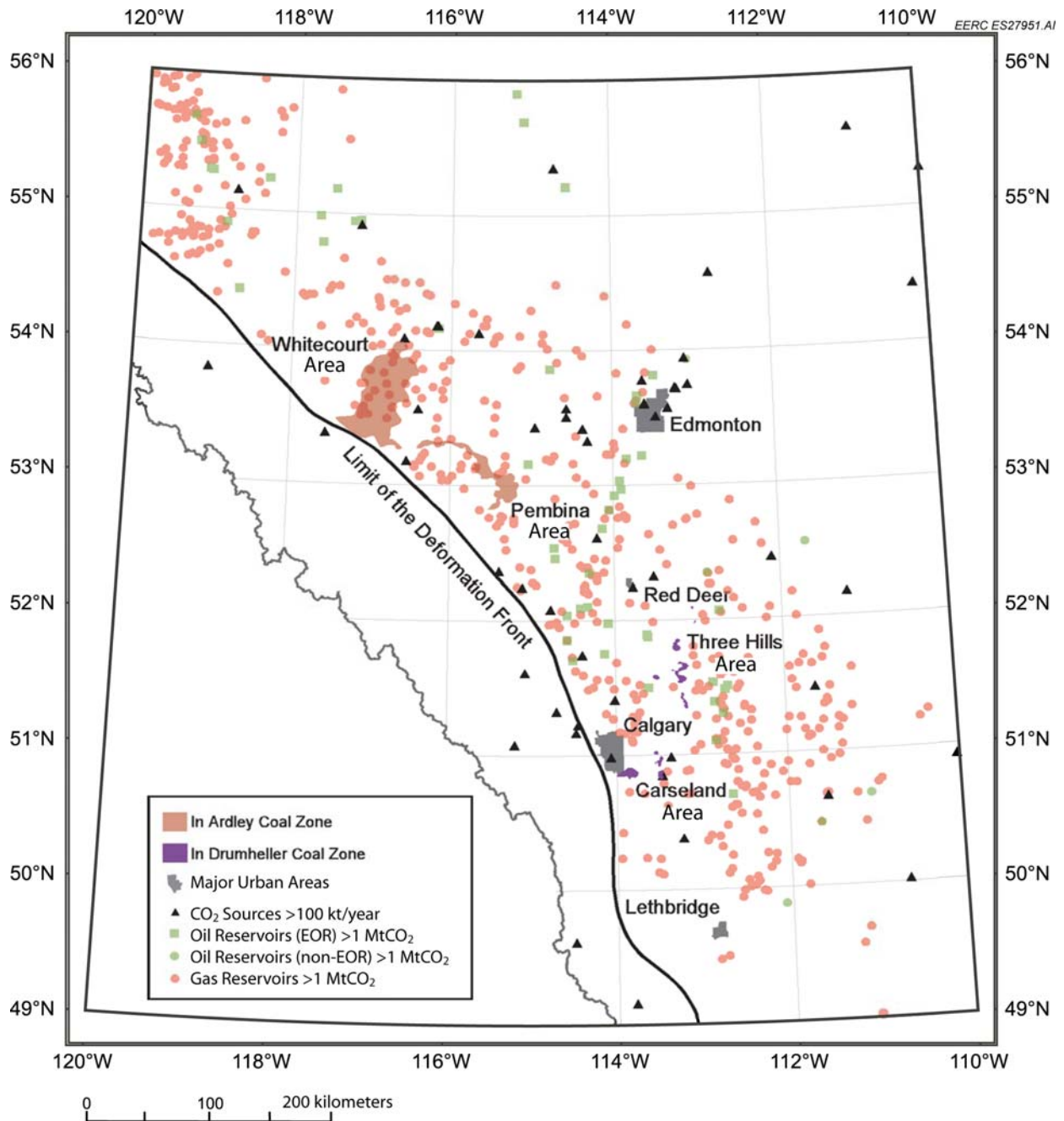
Figure 50. Location of the regions with high potential for CO_2 sequestration in coal beds in Alberta in relation to CO_2 sources and potential CO_2 sinks in oil and gas reservoirs.

- The Mannville Group is a major oil- and gas-producing stratigraphic interval in Alberta, and CO_2 injected into Mannville coals may leak and locally contaminate these resources.

- The coals are generally thin and of low cumulative thickness, particularly in the region east-northeast of Edmonton northeast where in situ pressure and temperature are below the critical point for CO_2 and which, consequently, would be a primary   region of interest for CO_2 storage.

- There are no major CO_2 sources in the region where the Mannville coals would be suitable, albeit at low capacity, for CO_2 sequestration, although, on the other hand, this region is closer than any other one to the oil sands and heavy oil operations in northeastern Alberta (Figure 50).

- There are no major potential CO_2 sinks in oil and gas reservoirs in this region (Figure 50) (Bachu and Shaw, 2004). Thus building the necessary infrastructure for delivering CO_2 in the northeast would be extremely uneconomical if other potential sinks are not available.

- This region is generally not suitable for CO_2 sequestration (Bachu and Stewart, 2002)

The Drumheller Coal Zone of the Horseshoe Canyon Formation has a practical sequestration capacity of only 55 MtCO_2 distributed in a few very small areas with high capacity in the Three Hills and Carseland areas northwest and east-southeast of Calgary, respectively (Figure 50). These areas are located in the agricultural heartland of Alberta, and CO_2 sequestration with concurrent CBM production may raise conflicts with other land use. The disadvantage of the Drumheller coals in terms of CO_2 sequestration is that the thick coals that would be good candidates for CO_2 storage are comparatively shallow and concentrated in a relatively narrow band around 300 m depth, i.e., close to shallow groundwater and to coals that may be mined in the future. Thus CO_2 storage in these coals is less recommended in order to protect groundwater resources and avoid sterilizing a potential future economical energy resource. Deeper Drumheller coals have no potential for CO_2 storage because they are very thin and of low capacity. There are many oil and gas reservoirs in the Three Hills and Carseland areas that may be used for CO_2 storage (Figure 50). Thus, while the coal beds in the Drumheller Coal Zone in these areas may not justify by themselves building the necessary infrastructure for delivering CO_2, they can be used for CO_2 storage as a matter of opportunity once infrastructure is in place to deliver CO_2 to oil and gas reservoirs in their vicinity.

In contrast to the Mannville and Drumheller Coal Zones, the Ardley Coal Zone has a much larger practical capacity for CO_2 sequestration, on the order of ~800 MtCO_2 in an area of ~3330 km^2 that comprises a large area in the Whitecourt region south of the Athabasca River and a narrow zone in the Pembina area (Figure 50). Both regions are located in forested lands which are less likely to become the object of land use conflicts. Because of low salinity and meteoric origin, water that would be produced with methane in CO_2 storage operations will not have to be treated, and it may even be possible to discharge it at surface. There are no oil or gas

resources in the Scollard and Paskapoo Formations that host and, respectively, overly the Ardley Coal Zone. On the other hand, there are many large potential CO_2 sinks in deep oil and gas reservoirs in the area (Figure 50) (Bachu and Shaw, 2004), and these areas in western Alberta are located within the most suitable region for CO_2 sequestration in western Canada (Bachu and Stewart, 2002). Furthermore, a significant number of major CO_2 sources are located in close proximity to or at acceptable distance (200–300 km) from the Whitecourt and Pembina areas (Figure 50). Thus an infrastructure pipeline that would bring CO_2 from large sources located to the east in the Edmonton–Lake Wabamun region would be used for a long period of time considering the large potential for CO_2 storage in oil and gas reservoirs and coal seams in these areas. Given the high CBM potential of the Ardley coals, CO_2 could be used in ECBM oil and gas recovery operations, thus producing additional oil and gas that would significantly increase the economics of CO_2 storage operations.

The analysis indicates that the Ardley Coal Zone in the Whitecourt and Pembina areas of west-central Alberta should be the primary target for CO_2 storage in uneconomical coal beds in Alberta.

CONCLUSIONS

Circumstantial evidence and increasing scientific consensus suggest that the world is currently witnessing a global-warming trend caused by increasing concentrations of GHG in the atmosphere as a result of burning fossil fuels for energy production. The Kyoto Protocol, which recently entered into force, binds developed countries to reduce by 2012 their atmospheric CO_2 emissions to set limits below 1990 levels. Canada committed to reduce its emissions to 6% below the 1990 level; however, current emissions are at more than 20% above. Currently, Alberta is the province with the largest CO_2 emissions in Canada at more than 230 $MtCO_2$/year, with most of the emissions originating in large stationary sources such as power plants, oil sand plants, refineries, upgraders, and cement plants. Alberta has committed to reduce by 2020 the GHG emission intensity to half of the 1990 level. CO_2 capture and geological sequestration is a means for reducing anthropogenic CO_2 emissions into the atmosphere that is immediately available and technologically feasible and that is particularly suited for Alberta as a result of its geology. Sequestration of CO_2 in coal seams, concurrent with methane production, is one of the possible means of CO_2 geological sequestration, together with sequestration in depleted oil and gas reservoirs and in deep saline aquifers. Cretaceous–Tertiary strata in Alberta contain eight coal zones, some of them with potential for CBM production and CO_2 sequestration. Based on their thickness and potential for CBM, three coal zones, Mannville in the Lower in Cretaceous Mannville Group, Drumheller the Upper Cretaceous Horseshoe Canyon Formation, and Ardley in the Upper Cretaceous–Tertiary Scollard Formation, have been identified for assessing their capacity for CO_2 sequestration.

The Mannville coals are found at depths that range from ~500 m in the northeast to more than 3000 m in the southwest at the Rocky Mountain deformation front and vary in thickness between less than 1 m and 16 m. Pressures vary from 3.2 MPa and ~30 MPa, while temperatures vary from ~16°C in the northeast to ~125°C at the deepest coal. Water salinity is high, varying from more than 2500 mg/L in the shallowest northeast to more than 130,000 mg/L in central Alberta. The Drumheller

coals of the Horseshoe Canyon Formation are found at depths that vary from ~40 m at outcrop beneath Quaternary sediments to ~1900 m in the west at the Rocky Mountain deformation front. Coal thickness varies between ~1 m over most of the area where these coals are present and 35 m in the east at shallow depth near outcrop. These coals are severely undepressured as a result of erosional and postglacial rebound, with pressures reaching only ~17 MPa at the Rocky Mountain deformation front. Pressures are up to 6 MPa less than hydrostatic, and these low pressures affect the adsorption capacity of these coals. Temperatures vary between 8°C at the shallowest coal and more than 60°C at the deepest coal. Water salinity is low, less than 2000 mg/L, in recharge areas near outcrop and reaches more than 15,000 mg/L in areas of severe undepressuring in the center of the coal zone. The Ardley Coal Zone dips southwestward, with depth varying between a few meters under the Quaternary drift at outcrop at the top of the bedrock in the east to 1160 m in the west at the eastern limit of the thrust and fold belt. The cumulative coal thickness varies between less than 1 m and 25 m. Pressures in the Ardley Coal Zone are generally hydrostatic, increasing with depth, similarly with temperatures that reach close to 30°C at the deepest coals. The water in the Ardley coals is of meteoric origin and has low salinity, generally less than 1000 mg/L, which qualifies it as potable water. Very few data exist about coal permeability, which decreases significantly with the effective stress exerted on these coals. Since the latter increases with depth, coal permeability displays a decrease with depth from several darcies in very shallow coals (less than 100 m deep) to a few milidarcies and less for coals several hundred meters deep. The direction of coal cleats is aligned with that of minimum horizontal stress in the basin and is generally perpendicular to the Rocky Mountain deformation front. Numerous coalfields exist along the outcrop of the Ardley and Horseshoe Canyon Coal Zones.

Regions suitable for CO_2 sequestration in these three coal zones have been defined on the basis of depth. Coals shallower than 300 m have been considered not suitable for CO_2 sequestration either because they may serve as aquifers or be in contact with aquifers used for potable groundwater resources, or because they may be mined at some time in the future and they should not be sterilized. On the other hand, coals deep enough such that the injected CO_2 would be in either liquid or supercritical phase were also deemed as unsuitable for CO_2 sequestration because of the permeability-losing behavior of coal in the presence of CO_2 in a phase other than gaseous. In addition, deep coals have low permeability and, furthermore, the presence of CO_2 further decreases coal permeability as a result of swelling. Low or loss of permeability affects CO_2 injectivity and CBM producibility. Thus, for each coal zone, a region of intermediate depth greater than 300 m but less than 800–900 m has been identified that, theoretically, is suitable for CO_2 sequestration.

The theoretical CO_2 sequestration capacity in the respective suitable region of each coal zone was estimated on the basis of CO_2 adsorption isotherms measured on coal samples, taking into account the moisture and ash content of these coals. The CO_2 theoretical sequestration capacity varies from ~20 ktCO_2/km^2 in the areas of thin coals to 1260 ktCO_2/km^2 in the areas of thick coals with high adsorption capacity, for a total of approximately 20 GtCO_2. This represents the ultimate sequestration capacity limit that would be attained if there would be no other gases present or they would be 100% replaced by CO_2 and if all the coals in the suitable regions will be accessed by CO_2. A recovery factor of less than 100% and a completion factor of less than 50% reduce the theoretical sequestration capacity to an effective sequestration capacity of

only 6.4 $GtCO_2$ for the three coal zones. The suitable regions will not be used for CO_2 sequestration in their entirety; however, because it will be uneconomical to build the necessary infrastructure (pipes, compressors, and a high density of wells) for areas with low sequestration capacity per unit surface. Considering that it is economical to build the necessary infrastructure for CO_2 sequestration only in areas with effective CO_2 sequestration capacity greater than 200 $ktCO_2/km^2$, then the CO_2 sequestration capacity in coal beds in Alberta is greatly reduced further to a practical capacity of only ~850 $MtCO_2$.

There are no suitable target areas with high CO_2 sequestration capacity in the Mannville Coal Zone. In addition, the Mannville coals would make poor candidates for CO_2 storage because of their depth, low permeability, elevated salinity of formation water that would be produced, the presence of oil and gas reservoirs in this stratigraphic interval that could be contaminated by leaked CO_2, and the absence of major CO_2 sources and potential CO_2 sinks within close distance, which would lower significantly the cost of CO_2 storage operations as a result of scale. In regard to the Drumheller Coal Zone of the Horseshoe Canyon Formation, there are a few very small areas with high capacity in the Three Hills and Carseland areas northwest and east-southeast of Calgary, respectively. The practical CO_2 sequestration capacity in these two areas is 55 $MtCO_2$. These areas are located in the agricultural heartland of Alberta, and CO_2 sequestration with CBM production may raise conflicts with land use. The Drumheller coals in these regions are relatively shallow (close to 300 m depth). CO_2 stored in these coals will likely sterilize shallow coal resources that may become economical for mining at some time in the future, and any leaked CO_2 from these coals will likely contaminate groundwater resources in these agricultural regions. In contrast to the Mannville and Drumheller Coal Zones, the Ardley Coal Zone has a much larger practical capacity for CO_2 sequestration of ~800 $MtCO_2$ in an area of ~3330 km^2 that comprises a large area in the Whitecourt region south of the Athabasca River and a narrow zone in the Pembina area. Both regions are located in forested lands which are less likely to become the object of landuse conflicts. Besides the fact that this region is located in a forested area, the low salinity of water in the Ardley coals adds the advantage that produced water does not have to be treated and it is possible that it could even be discharged at surface if Alberta Environment regulations are being met. There are no oil or gas reservoirs in the stratigraphic vicinity of Ardley coals, but there are many large potential CO_2 sinks in deeper oil and gas reservoirs in these areas. Large stationary CO_2 emitters are located within close distance of these areas. Infrastructure built to bring CO_2 from large CO_2 sources in the Edmonton–Lake Wabamun region located to the east will be economical given the large number of potential CO_2 sinks in western Alberta, comprising the Whitecourt and Pembina areas, and the large storage capacity of these sinks. Given the high CBM potential of the Ardley coals, CO_2 could be used in ECBM oil and gas recovery operations, thus producing additional oil and gas that would significantly increase the economics of CO_2 storage operations. Thus the Ardley Coal Zone in the Whitecourt and Pembina areas of western Alberta should be the primary target for CO_2 storage in coals in Alberta.

Having identified on a regional scale the best areas and coal beds for CO_2 storage in Alberta's coals, the next step should be the screening and identification of specific sites for implementation on the basis of detailed geological characterization and testing of the coals. Site selection should be based on coal structure, thickness,

permeability and gas content, coal geometry and confinement, and infrastructure and economics associated with CO_2 storage and CBM production.

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