Unconventional Gas

The environmental challenges of coalbed methane development in Alberta

June 2003

REPORT

Mary Griffiths and Chris Severson-Baker

the PEMBINA institute
Sustainable Energy Solutions

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About this Report

As supplies of conventional natural gas decline and prices rise, the extraction of gas from coal seams will increase. Many companies are exploring or developing coalbed methane (CBM) in central and southern Alberta, where the estimated resources are the largest in Canada.

This report shows the distinctively different character of much CBM development compared to conventional oil and gas exploration. It describes how the density of CBM wells and the large land base that may be affected raise concerns about cumulative impacts and land fragmentation by wells, pipelines and roads.

The report demonstrates that, while there are differences between CBM production from coal seams containing non-saline water, saline water or no water, impacts may include air emissions from venting and flaring, gas migration, noise from compressors, and the dewatering of non-saline water aquifers when CBM is extracted from shallow coal seams.

This report offers recommendations for improved regulations and shows how some impacts may be reduced through the use of best practices. The list of key questions at the end serves as a "citizens' guide," enabling landowners and other stakeholders to understand the critical issues and ask the right questions about projects on their land or in their area.

Acknowledgements and Disclaimer

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About the Authors

Mary Griffiths is the primary author of this report. She joined the Pembina Institute as an Environmental Policy Analyst in May 2000 to work with the Energy Watch program. She was co-author of the book *When the Oilpatch Comes to Your Backyard: A Citizens' Guide to Protecting Your Rights*, published by the Pembina Institute in 2001. Mary was also the lead author of *Oil and Troubled Waters: Reducing the Impact of the Oil and Gas Industry on Alberta's Water Resources,* posted on the Pembina Institute Web site in April 2003. Mary works on air quality issues as a member of the Board of Directors of the West Central Airshed Society and with subcommittees of the Clean Air Strategic Alliance. She has helped evaluate the environmental impact of energy projects, including oilsands developments and coal-fired power plants. Mary is currently reviewing the environmental impacts of new developments in Alberta, such as the extraction of coalbed methane and the underground storage of carbon dioxide. She has long been an advocate for the protection of the environment, both in her previous employment and in her volunteer activities. Mary holds a PhD (Medical Geography), University of Exeter, UK and a BA (Geography), University of Exeter, UK.

Chris Severson-Baker graduated from the University of Alberta with a BSc in Environmental and Conservation Science in 1996, the same year he joined the Pembina Institute. He has worked to reduce the impacts of the oil and gas industry on the environment, by lobbying government for more stringent regulations and encouraging industry to adopt better practices. Chris has been the environmental non-governmental (ENGO) representative on several project teams with the Clean Air Strategic Alliance and is currently the co-chair of the Flaring and Venting Project Team. He has also served as the ENGO representative on the Upstream Oil and Gas Industry Sub-group of the National Pollutant Release Inventory. Chris has been active with the Alberta Environmental Network and was its co-chair from 1999 to 2002. At present Chris is the lead writer of a series of primers about oil and gas development and best practices for Arctic Canada, and has organized workshops for persons from aboriginal communities, regulatory agencies and environmental groups from the Yukon and Northwest Territories. In 2003 he became the Deputy Director of the Pembina Institute Energy Watch program.

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Executive Summary

The term "unconventional gas" applies to natural gas from coal seams, tight gas sands, gas shales and gas hydrates. The most significant source of unconventional gas in Alberta is natural gas from coal seams and is most commonly referred to as coalbed methane (CBM). As demand for natural gas continues to grow and the supply of conventional natural gas declines, attention has turned to CBM. By 2002, the US obtained 9% of its gas supply from CBM, and development has recently begun in Alberta and BC. It has been estimated that over 60% of Canada's CBM resource is in Alberta. The coal seams that lie under most of central and southern Alberta contain very large amounts of CBM. It is not known how much of this resource can be extracted, but Canada's CBM reserves are estimated to be about 60 trillion cubic feet (Tcf), with over 20 Tcf in Alberta, excluding the Foothills region. For comparison, the total production of conventional natural gas in Alberta to date is over 100 Tcf and the remaining conventional natural gas reserves are slightly over 40 Tcf.

Coal beds between 150 and 1600 metres deep are currently being explored in Alberta. In addition to exploratory wells there are extensive pilot projects underway and two companies started commercial production in 2002. In some formations, the coal is dry and CBM can be extracted in the same way as conventional natural gas from shallow formations. More commonly, it will be necessary to dewater the coal to reduce the pressure and allow the gas to be extracted.

The extraction of CBM differs from conventional natural gas production in several respects, especially where the coals need to be dewatered. Key environmental issues can include land disturbance from the high density of wells; surface water and groundwater impacts associated with the dewatering of coal seams; venting and prolonged flaring of non-economic gas; and noise pollution from compressors and pumps required to produce CBM (see the table below). Experience with CBM development in the US has demonstrated that these issues can have significant impacts. While the geological conditions in Alberta differ somewhat from those in the US, it is important to learn from the US experience and avoid or reduce potential impacts in Canada with pro-active, effective regulation and the adoption of best practices by industry.

The Alberta Energy and Utilities Board currently regulates CBM in the same way as conventional natural gas. However, if the coal seams contain non-saline water, a company must also apply to Alberta Environment to dewater the coals. Alberta Energy has initiated a review and cross-government consultation process to determine how existing rules should be modified for CBM development. They plan an external consultation phase, to involve industry, landowners, environmental organizations and other stakeholders. This report by the Pembina Institute provides ideas for public input on decisions relating to CBM, both with respect to the regulatory process and for individual projects.

The report makes a number of recommendations on ways in which regulations should be improved to reduce the risk of harmful impacts. One recommendation is that for large-scale CDM projects (that is, extensive pilot projects and commercial projects) environmental impact assessments (EIAs) should be conducted. This would enable the examination of the cumulative environmental and social impacts of CBM development and the establishment of plans to minimize these impacts if development proceeds. Currently, even though the surface area affected may be as great as for heavy oilsands projects (for example, the steam-assisted gravity drainage process) for which an EIA is required, conventional oil and gas projects are exempt from the EIA process. Setback distances, as well as the regulatory process for the protection of groundwater, also need to be reviewed.

Some potential impacts of CBM well development

Issue	Description	Potential impact
High density of wells	An average of two to eight wells per section to access the gas compared to the basic standard of one well per section for conventional natural gas.	Disturbance of land surface by well pads, pipelines and roads. Land disturbance and fragmentation results in loss of wildlife habitat and affects animal behavioural patterns; it also has an impact on native vegetation and farming operations.
Dewatering of coal	While some coal seams are dry, many will require significant amounts of dewatering to relieve pressure before gas can be extracted. Conventional gas wells generally produce no water at the start of development, although water may be pumped from a well as it ages.	Dewatering of non-saline aquifers where coal seams are shallow, which could impact fresh groundwater supplies needed for human use and to recharge surface water bodies.
Venting and flaring of CBM gas	During dewatering, CBM may be vented or flared until gas volumes are sufficiently economic to pipeline. The duration will likely be for much longer periods than that experienced with conventional gas wells.	Local air pollution and an increase in greenhouse gas emissions are key human health and environmental issues of concern.
Noise	Where coal seams need dewatering, the lower gas pressure and higher density of CBM wells compared to conventional gas wells will result in increased intensity of pumps and compressors used to dewater the coal seams and pressurize the gas.	Elevated noise levels created by this equipment can contribute to degradation of rural lifestyle aesthetics and disturb wildlife patterns.

Recommendations for industry best practices that can reduce impacts include a proposal for multiple wells to be drilled directionally from a central pad wherever technically feasible. This would allow wells to be concentrated along road and pipeline corridors, limiting land fragmentation and impacts on both agricultural land and natural habitat.

The report concludes with a list of questions that landowners or others potentially impacted by CBM development can ask a company or regulators before the start of operations, so they can better understand the potential impacts of developments in their area.

1. Setting the Scene

1.1 Why coalbed methane?

Demand for natural gas continues to increase in North America, but reserves of conventional natural gas are declining. The increasing price of natural gas and, in some cases, government policies have encouraged the exploration and development of gas from unconventional sources. The term "unconventional gas" applies to natural gas from coal seams, tight gas sands, gas shales and gas hydrates.[1] This report examines the challenges associated with the development of natural gas from coal seams, or coalbed methane (CBM) as it is often called, since this is the focus of much of the current unconventional gas development in Western Canada. The extraction of CBM has the potential to spur a major new wave of development by the upstream oil and gas industry in Alberta and BC. This new round of drilling, production and pipelining will affect many people and lands that have experienced oil and gas development in the past, while some development may occur in new areas that have no history of gas extraction. In some areas of BC, for example Vancouver Island, CBM may be the first experience that people have with the environmental impacts associated with gas extraction.

The American demand for gas is such that the US now takes over 57% of Canadian production and exports have grown in each of the last 16 years.[2] At the same time, natural gas production from conventional gas wells in the Western Canadian Foothills and Prairie region has been levelling off because the initial productivity of new wells is lower than in the past.[3] Thus, even though there is an increase in the number of new wells drilled each year, the National Energy Board forecasts that the daily delivery of natural gas from the region will decline. This decline in conventional natural gas resources is spurring interest in developing frontier regions in the far North (such as the Mackenzie Delta) as well as in exploiting unconventional sources such as CBM. Many companies that have developed conventional gas resources, as well as some new players, are currently exploring for CBM in Alberta and BC. In the fall of 2002, two companies started commercial production of natural gas from coal seams in Alberta.[4]

CBM wells and associated facilities are clearly seen on the landscape. In addition to generating noise, they will likely impact air and water quality. The effect on the landscape will be greatest

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[1] See Canadian Society for Unconventional Gas Web site for more details on these gases: http://www.csug.ca
[2] Enviroline. 2002. Volume 13, No.19–20, *Energy Issues*, p. 8.
[3] National Energy Board. 2002. *Short-term Natural Gas Deliverability from the Western Canada Sedimentary Basin 2002–2004,* p. v.; http://www.neb.gc.ca/energy/ema_stngd_wcsb-2002_2004_e.pdf. The Western Sedimentary Basin includes the gas-producing regions in the Foothill zone in BC, east of the Rockies, Alberta and Western Saskatchewan. Total production of conventional natural gas in this region is expected to decline from 470 million cubic metres per day (m^3/d) (16.6 billion cubic feet per day (Bcf/d)) in 2001 to 450 million m^3/d (15.9 Bcf/d) by the end of 2004.
[4] EnCana Corporation. 2002. *EnCana Cash Flow Tops $1 Billion in Third Quarter*. News release, November 5; http://www.encana.com/news_and_views/4_0_20021105_1.shtml; Canada NewsWire. 2002. *Quicksilver Resources Announces Commercial Coal Bed Methane Development*. News release. October 17. Quicksilver Resources Inc. is the parent company of MGV Energy Inc., operating in Alberta; http://www.newswire.ca/releases/October2002/17/c2034.html

in wilderness areas and areas that do not already have an existing network of roads and pipelines. Yet, even in areas where oil and gas developments have already imprinted on the land, the additional effects of CBM operations may be dramatic due to the large number of well sites that may be needed.[5]

This report is intended for the layperson and provides an overview of the basic mechanics of how CBM is extracted, summarizes activities to date in Alberta, outlines the key environmental issues and makes recommendations for the management of CBM development. It also contains questions that landowners may wish to ask about proposed developments on their land. While the focus is on the situation in Alberta, reference is also made to developments in the US and in BC.[6] Although the coal formations in the Prairie provinces differ from those in the US Rockies, and the regulatory regime is different in Alberta, it is important that we learn from the US experience and avoid problems that have been encountered in, for example, the Powder River Basin in Wyoming and Montana.[7] Some information about the potential environmental impacts of CBM development in Alberta will be relevant to other areas in Canada, but differences in geology and provincial regulations must also be considered. The solutions for best practices and other recommendations may not always be applicable in other regions.[8]

1.2 What is coalbed methane?

CBM is the natural gas found in coal seams. It is also referred to as "natural gas from coal."[9] Historically CBM has been viewed as a danger for coal miners, due to the risk that it would explode, rather than as a source of energy.

Millions of years ago deeply buried plant materials were converted to coal due to the effects of high pressure and heat. The process also led to the formation of methane gas and water. Much of the methane gas is adsorbed on the internal surfaces of the coal at a molecular level and held in place by the pressure of the overlying rocks and by water in the coal seams. Methane is also stored in tiny cracks, called cleats, in the coal seams. CBM thus differs from conventional natural gas found in pore spaces in, for example, sandstone or limestone formations. CBM is typically a sweet gas, usually consisting of more than 90% pure methane with small amounts of

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[5] The number of wells required will vary. While more wells are very likely, in some of the dry coal areas, the new wells may be on the same pads as existing conventional wells, since existing wells are converted.

[6] West Coast Environmental Law has reviewed the potential impacts of CBM development in BC: West Coast Environmental Law. 2003. *Coalbed Methane: What Is It? What Could it Mean for BC?;* http://www.wcel.org/wcelpub/2003/13928.pdf; and *Coalbed Methane: A Citizen's Guide;* http://www.wcel.org/wcelpub/2003/14027.pdf

[7] mHeath & Associates. September 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta.* Prepared for Alberta Energy, "Table 1: CBM Basin Characteristics," p. 27; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf This table compares the main characteristics of four US CBM basins with three in Alberta.

[8] For example, the disposal of water pumped up from CBM wells will vary, not only with different government requirements, but also with the geological conditions.

[9] This term is used by the Alberta Department of Energy and the Canadian Society for Unconventional Gas.

other substances such as carbon dioxide (CO_2) and nitrogen.[10] Conventional natural gas, by comparison, usually contains 70–90% methane with varying amounts of other gases.[11]

1.3 Where is coalbed methane found?

CBM is found wherever there is coal. The main CBM resources in North America are shown in Figure 1.

While there is some coal in the Maritimes, Canada's most important coal seams are in the extensive areas of sedimentary rocks, which lie between the Canadian Precambrian Shield in the east and the Rocky Mountains in the west. Although coal seams are found in southern Saskatchewan, the most extensive formations for CBM are in Alberta and in the Peace River coalfield in BC, which is part of the same geological region. The Yukon also has extensive coal seams but it is not known if they will be suitable for the economic extraction of CBM.[12] Developments in the Peace River area of BC will likely be similar to those in Alberta. In the interior valleys of BC the geological situation of the coal seams may be more comparable to conditions found in the Rocky Mountain area of the US, while on Vancouver Island it will be different again.

The actual amounts of methane gas vary from one coal seam to another, even within the same geological formation. In general, in Western Canada more CBM gas is found in high-ranking coal, such as bituminous coals found at greater depths and towards the Rockies, than in the lower-ranking sub-bituminous coals and lignite found as one moves to the east (Figure 2).[13] The amount of gas recovered from CBM wells also varies but may be as high as or higher than in a conventional gas well.[14, 15]

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[10] Canadian Society for Unconventional Gas. 2003. *Natural Gas from Coal: Overview Presentation,* slide 3; http://www.csug.ca/cbm/dl/NGCoverview.pdf CBM does not usually contain any hydrogen sulphide (H_2S), which typifies sour gas. A little biogenic H_2S (that is, gas produced by living organisms) has been found in surface mining of coal seams in the Aztec region of the San Juan Basin in New Mexico, but only in shallow regions where there is access to surface water. This is extremely rare. S. Hayden, New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division, District 3, personal communication, June 2003.

[11] In addition to methane (CH_4), conventional natural gas may contain up to 20% of ethane (C_2H_6), propane (C_3H_8) and butane (C_4H_{10}), as well as some nitrogen, helium, CO_2 and hydrogen sulphide.

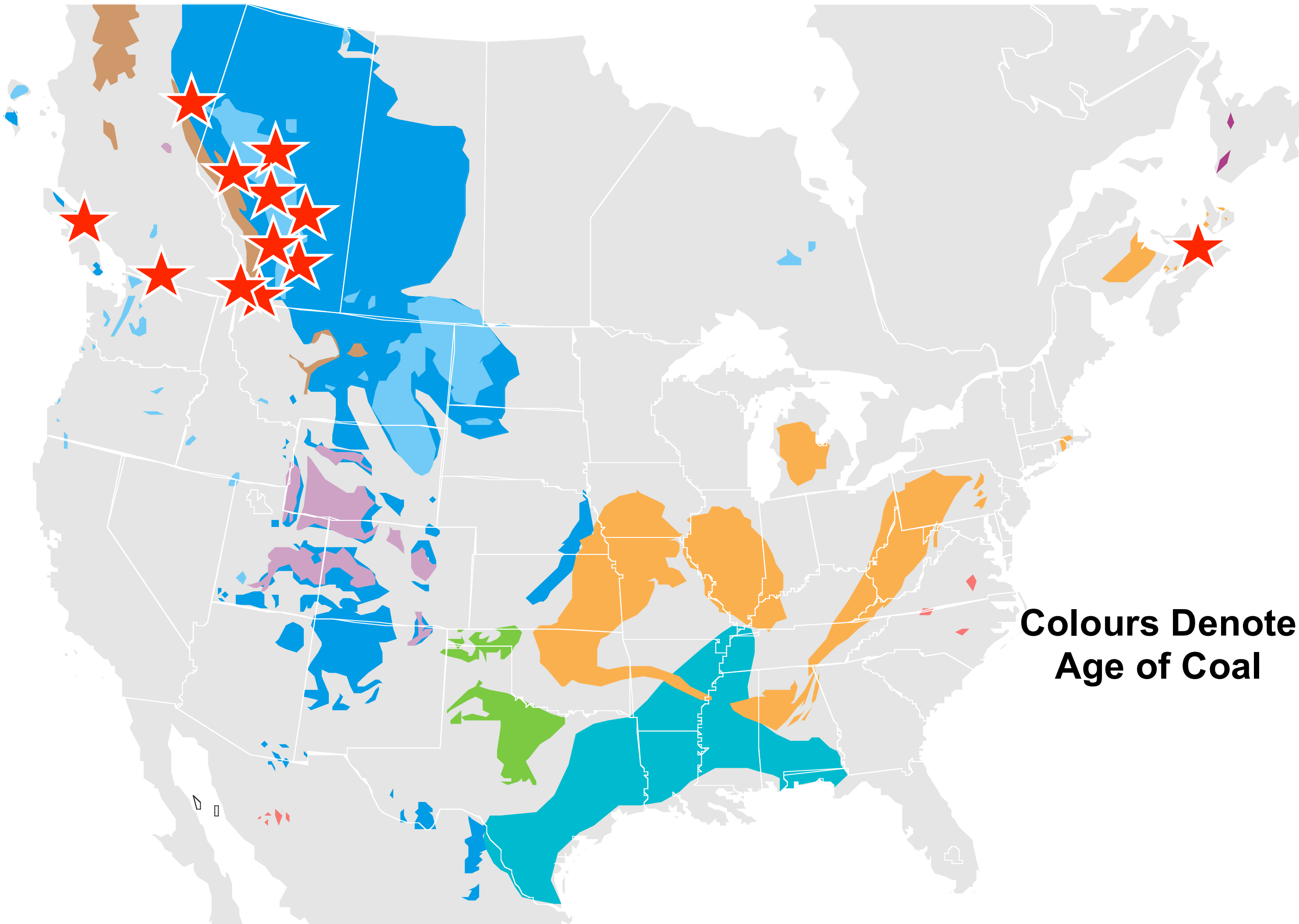
[12] Government of Yukon, Department of Energy, Mines and Resources, *Alternative Energy, Coalbed Methane*; http://www.emr.gov.yk.ca/Energy/Alternative_Energy_Resources.htm#Coal%20Bed%20Methane

[13] The rank of coal depends on its thermal maturity, and thermal maturity usually increases with depth. The ranking of coal from lowest to highest is lignite, sub-bituminous, bituminous, anthracite. Chemical changes occur in the coal as the thermal maturity increases (that is, as the rank increases) that result in more gas cleaving off from the coal. A. Beaton, Alberta Geological Survey, Alberta Energy and Utilities Board, personal communication, May 2003.

[14] Spirit Energy Corp. *About Coalbed Methane*; http://www.spiritenergy.ca/about.html

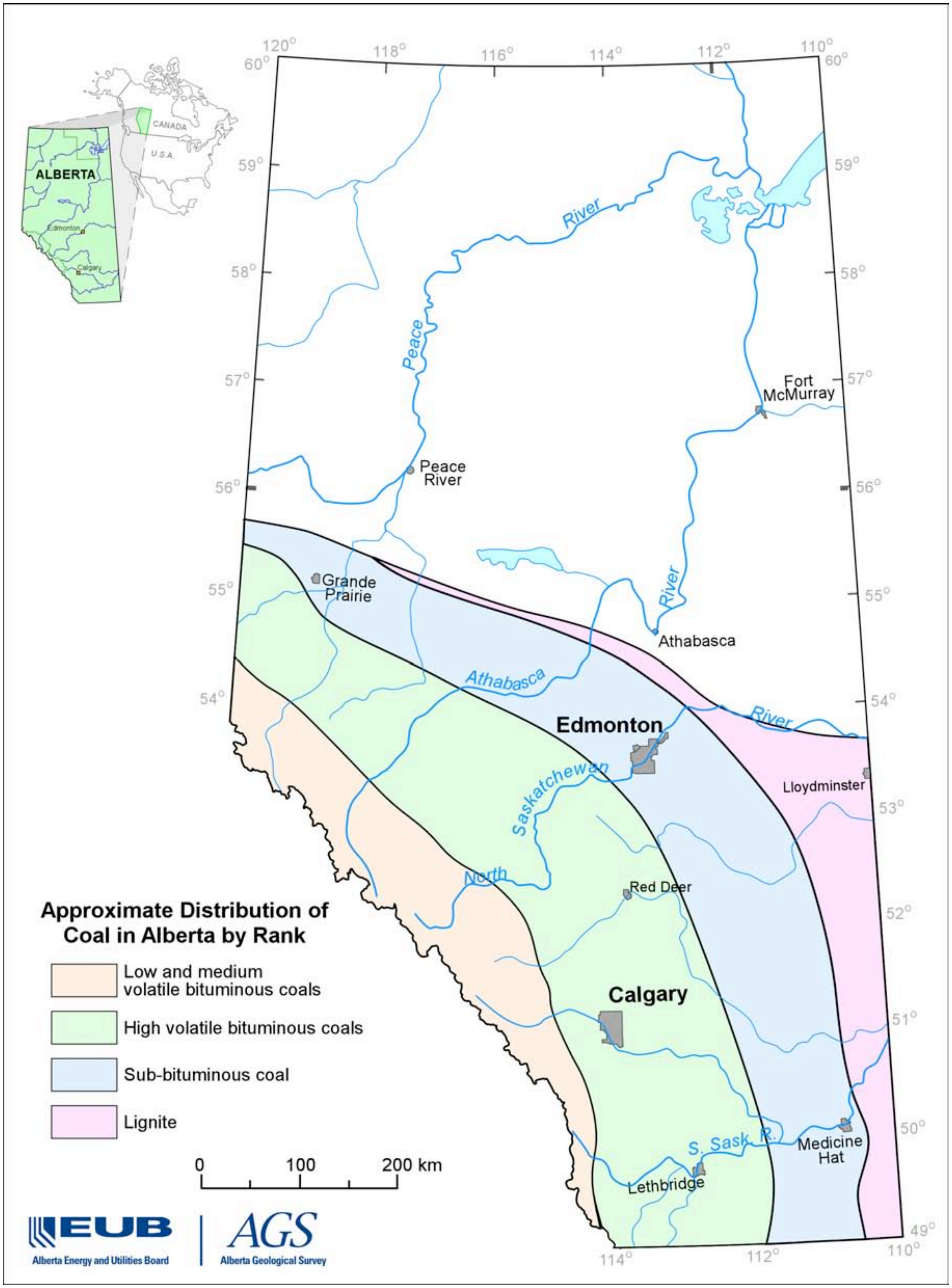
[15] Typical CBM recovery efficiencies range from 60–80%, although in the US they reach as high as 98% in part of the San Juan Basin, but are as low as 20–40% in very wet parts of the Powder River Basin. For comparison, in conventional dry natural gas reservoirs it is possible to get 80–95% recovery, although in tight gas reserves (that is, where the permeability is very low) the recovery rate is 20–40%. In water-driven gas reservoirs (where water encroaches and traps natural gas), the recovery rate is approximately 40–60%. D. Cox, Trident Exploration Corp., personal communication, May 2003.

Figure 1: Natural Gas from Coal in Canada — Areas of Exploration



With permission from Canadian Society for Unconventional Gas

Figure 2: Approximate Distribution of Coal in Alberta by Rank



With permission from the Alberta Geological Survey, Alberta Energy and Utilities Board.

The first CBM wells in the US were drilled about twenty years ago in the Black Warrior Basin in Alabama and in the San Juan Basin, which lies astride the Colorado/New Mexico border. The development was encouraged by government incentives. By the year 2000 there were over 10,000 CBM wells[16] throughout the US, and in 2002 CBM supplied 9% of the country's natural gas production.[17] CBM is now extracted from coal seams across the US from the Appalachians to the Rockies, including rapidly expanding development in the Powder River Basin in Wyoming and areas of Montana.[18, 19]

The estimates of Canada's CBM resources are changing as new information becomes available, but the Canadian Society for Unconventional Gas estimates the total CBM resource in Canada to be between 182 and 553 trillion cubic feet (Tcf), with approximately 60% of the resource being in Alberta.[20, 21] By May 2003, work by the Alberta Geological Survey indicated that the total maximum resource-in-place in Alberta is approximately 500 Tcf.[22] The other main CBM resources are in British Columbia.[23, 24] It is important to distinguish between the total resource-in-place and the reserves. The CBM reserve, that is the volume that can be recovered, depends

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16 Holditch, S., Schlumberger. 2002. *The Increasing Role of Unconventional Reservoirs in the Future of the Oil and Gas Business,* Presentation to the Fourth Annual Unconventional Gas and Coalbed Methane Conference, October 23–25, 2002. Calgary, Alberta, Petroleum Technology Alliance Canada and Canadian Society for Unconventional Gas.

17 Pinkser, L. 2002. Coalbed methane: The future of U.S. natural gas? *Geotimes,* November; http://www.agiweb.org/geotimes/nov02/resources.html See also: United States Geological Survey. 2000. *Coal-Bed Methane: Potential and Concerns*, USGS Fact Sheet FS–123–00; http://pubs.usgs.gov/fs/fs123-00/fs123-00.pdf The in-place CBM resources in the US are estimated to be more than 700 Tcf, of which 100 Tcf might be economically recoverable with current technology. This is equivalent to a five-year gas supply at the current rate of use in the US. United States Geological Survey Energy Resource Surveys Program, 1997. *Coalbed Methane — An Untapped Energy Resource and an Environmental Concern*, USGS Fact Sheet FS–019–97; http://energy.usgs.gov/factsheets/Coalbed/coalmeth.html

18 Holditch, S., Schlumberger. 2002. *The Increasing Role of Unconventional Reservoirs in the Future of the Oil and Gas Business,* Presentation to the Fourth Annual Unconventional Gas and Coalbed Methane Conference, October 23–25, 2002. Calgary, Alberta, Petroleum Technology Alliance Canada and Canadian Society for Unconventional Gas.

19 Western Governors' Association. 2002. *Coal Bed Methane Development in the West.* Environmental Summit on the West II: Breakout Session I, April 18, 2002; http://www.westgov.org/wga/initiatives/enlibra/methane_summit_II.htm

20 Canadian Society for Unconventional Gas. 2003. *Natural Gas from Coal, Overview Presentation;* slide 13. Total resource for Canada is 182 to 553 Tcf (equivalent to 5,200 to 15,700 billion m^3); http://www.csug.ca/cbm/dl/NGCoverview.pdf. Slide 14 shows the minimum estimates of natural gas from coal in place (that is, coalbed methane) are 40 Tcf BC (maximum 119 Tcf); 20 Tcf in the Alberta Foothills (maximum 60 Tcf) and 115 Tcf in the Alberta Plains (maximum 353 Tcf). In this Pembina Institute document all figures are given in the Imperial measure of cubic feet, which is also the measure used by Alberta Energy. In the footnotes, some figures are converted to metric, which is the unit used by the Alberta Energy and Utilities Board. One trillion cubic feet (1 Tcf) is approximately equivalent to 28 billion m^3. A trillion is 1,000 billion. A billion is 1,000 million.

21 The Canadian Association of Petroleum Producers has a figure of 190 Tcf for Canada's CBM resource, which is nearly 5,400 billion m^3. Canadian Association of Petroleum Producers, *Towards Responsible Coalbed Methane Development in Canada; http://www.capp.ca/default.asp?V_DOC_ID=843*

22 A. Beaton, Alberta Geological Survey, personal communication, June 2003. The amount that can actually be recovered will be less than this and has yet to be determined.

23 Woronuk, R.H. *Canadian Natural Gas Resources*. Canadian Gas Potential Committee. p. 10; http://www.canadiangaspotential.com/papers_presentations/opipaper2001.pdf

24 Ministry of Energy and Mines, British Columbia. 2001. *Coalbed Methane in British Columbia;* http://www.em.gov.bc.ca/Mining/Geolsurv/coal/Coalmeth/CBMbrochure.htm

on what is technically and economically feasible. The recoverable reserves of CBM in Canada have been estimated to be 60 Tcf[25] and the reserves in the Alberta Plains are estimated at over 20 Tcf.[26] For comparison, the cumulative production of marketable natural gas in Alberta until 2001 was 106 Tcf and remaining established reserves of conventional natural gas are approximately 41Tcf.[27]

The BC government has evaluated the province's CBM potential resource as being 90 to 250 Tcf with a potential for recovery between 18 and 50 Tcf.[28] Several experimental schemes are underway.[29] Two-thirds of BC's CBM resources are in the Peace River coalfield, which, as noted above, is an extension of the coal in the Prairie provinces.[30] The BC government is encouraging development of CBM through the implementation of a new royalty regime.[31]

Future scenarios prepared by the National Energy Board show that CBM development in Canada is expected to increase gradually from 300 wells in 2002 to 3,000 wells annually by about 2025[32] when CBM might provide approximately 15% of Canada's gas supply.

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[25] This figure is derived from National Energy Board estimates in *Canada's Energy Future: Scenarios for Supply and Demand to 2025. Draft for Public Consultation,* January 2003, p. 53; http://www.neb.gc.ca/energy/sd0203/publicconsultation_e.pdf The NEB estimated 75 Tcf recoverable unconventional gas in Canada, primarily from Alberta and BC. This includes not only CBM but tight gas, gas shales, etc. The Canadian Society for Unconventional Gas estimates that 15 Tcf of this total could come from gas shales, etc., with the remaining 60 Tcf coming from CBM. These estimates were made prior to the May 2003 results of the Alberta Geological Survey work.

[26] It is estimated that the CBM reserves in the Alberta Plains are 22 Tcf. M. Gatens, MGV Energy Inc., personal communication, May 2003. These estimates were made prior to the latest survey results of the resource in place by the Alberta Geological Survey.

[27] Alberta Energy and Utilities Board. 2002. *Alberta's Reserves 2001 and Supply/Demand Outlook 2002–2011,* Chapter 4, Natural Gas and Liquids, p.4-1; http://www.eub.gov.ab.ca/bbs/products/STs/ST98-2002.pdf Total production until 2001 was 106 Tcf (3,000 billion m^3) and remaining reserves are approximately 41Tcf (approximately 1,140 billion m^3).

[28] Ministry of Energy and Mines, British Columbia. 2001. *Coalbed Methane in British Columbia*, p. 1.; http://www.em.gov.bc.ca/Mining/Geolsurv/coal/Coalmeth/CBMbrochure.htm. For more detail, see BC Ministry of Energy and Mines. 2000. *Coalbed Methane Potential in British Columbia*, Geofile 2000–7; http://www.em.gov.bc.ca/DL/GSBPubs/GeoFile/Gf2000-7/GF2000-7.pdf

[29] BC Oil and Gas Commission. 2002. Coalbed methane drilling update. *Commissioner's Update* 1, no. 2:2. The first CBM well site was drilled on Vancouver Island in 2002; http://www.ogc.gov.bc.ca/documents/commissupdate/Commissup_may2002.pdf

[30] BC Ministry of Energy and Mines. 2000. *Coalbed Methane Potential in British Columbia*, Geofile 2000-7, p.1; http://www.em.gov.bc.ca/DL/GSBPubs/GeoFile/Gf2000-7/GF2000-7.pdf

[31] BC Ministry of Energy and Mines. 2002. *Changes Extend Base 9 Royalty and Create New Coalbed Methane Royalty*. Information Bulletin. March 14, 2002; http://www.em.gov.bc.ca/subwebs/InfoletRR/OilandGas/2002/newsrelib-01.htm The new royalty regime for CBM provides a $50,000 royalty credit for wells drilled within two years of the announcement and several other provisions that recognize the specific development and production costs associated with CBM.

[32] National Energy Board. 2003. *Canada's Energy Future: Scenarios for Supply and Demand to 2025.* Draft for Public Consultation; http://www.neb.gc.ca/energy/sd0203/publicconsultation_e.pdf The estimate in the above text, that approximately 15% of gas production in 2025 will come from CBM, is derived from the graphs on p. 54. This document provides two different scenarios for future gas production, but in both scenarios the development of CBM is similar. Each CBM well is expected to commence production at a rate of 100 Mcf/d and to recover 0.375 Bcf.

2. What is the Potential for Coalbed Methane Development in Alberta?

In the early 1990s, the Alberta Geological Survey conducted a study with an industry consortium to evaluate the CBM resource in Alberta. The Coalbed Methane Task Group was set up in 1991, with representatives from government, industry and the public to review the potential in Alberta.[33, 34] There was, however, little commercial interest in CBM development at that time, due to the abundance of cheap, accessible natural gas. More recently, with the increasing demand for natural gas and its rising price, attention has again focused on the province's CBM resources. Alberta Energy commissioned a study in 2001 to examine the potential for CBM development in this province and the implications of such development.[35] While their report provides useful information, since the time it was completed understanding of Alberta's coal seam geology and production information has increased, due to work conducted by the Alberta Geological Survey and publicly available industry data.[36]

The Alberta Geological Survey is conducting a three-year study to more carefully delineate the CBM resource and identify areas with high gas content,[37] which will be completed during 2003.[38] As indicated above, by May 2003 it was estimated that the total maximum resources (in place) in the province is approximately 500 Tcf. The amount that can be actually recovered will be less than this and has yet to be determined.[39] The shallow to moderately deep Ardley, Horseshoe Canyon and Belly River strata offer good prospects for CBM exploration,[40] and

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[33] The Coalbed Methane Task Group. 1993. *Coalbed Methane in Alberta.*
[34] Byrnes, T.L. and K.F. Schuldhaus. 1995. Coalbed methane in Alberta. *The Journal of Canadian Petroleum Technology,* 34, no. 3:57–62.
[35] Alberta Energy. 2002. *Alberta Examines the Potential for Coalbed Methane Development*. News release, October 22; http://www.gov.ab.ca/acn/200210/13392.html See also mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta*. Prepared for Alberta Energy; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf This study involved a cross-section of regulatory agencies (including the Alberta Energy and Utilities Board, Alberta Environment, National Energy Board, US Bureau of Land Management and various US state oil and gas conservation commissions) and research organizations (including the Alberta Research Council, Alberta Geological Survey and the Geological Survey of Canada). It also included input from a US landowner with extensive CBM experience, since there was no CBM development in Alberta at that time. The Executive Summary of the report can be found at http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Summary.pdf. Note that the page numbers in the Executive Summary do not correspond with those as printed in the main document, which are the ones cited in this report.
[36] S. Rauschning, Alberta Energy, personal communication, June 2003.
[37] Alberta Energy. 2002. *Alberta Examines the Potential for Coalbed Methane Development*. News release and Backgrounder, October 22; http://www.gov.ab.ca/acn/200210/13392.html
[38] Alberta Geological Survey. 2002. Alberta Foothills coalbed methane potential. *Rock Chips,* Fall/Winter:2; http://www.ags.gov.ab.ca/publications/ROCKCHIPS/fallwinter02.pdf
[39] A. Beaton, Alberta Geological Survey, personal communication, June 2003.
[40] Bachu, S. 2002. *Flow of Formation Water and Coal Permeability: Indicators of Exploration Target Areas for CBM in Alberta's Upper Cretaceous-Tertiary Strata*. Alberta Geological Survey. Fourth Annual Unconventional Gas and Coalbed Methane Conference, October 23–25, 2002. Calgary, Alberta, Petroleum Technology Alliance Canada and Canadian Society for Unconventional Gas.

companies are also drilling the deeper Mannville formations.[41] Although the formations are often named after one specific location, these strata are extensive across central Alberta. The location of coal seams with CBM potential in Alberta is shown in Figure 3, while Figure 4 illustrates a cross-section of the geological structure in central Alberta.

Following a pilot study, EnCana Corporation and their partner MGV Energy Inc. announced in fall 2002 that they had started Canada's first commercial CBM project.[42] The companies are drilling on their lands east of Calgary and also evaluating the CBM potential at other locations. In 2002, the nearly 30 companies exploring in Alberta drilled between 150 and 200 CBM wells; by early 2003 there were approximately 400 CBM wells in the province.[43] This compares with approximately 8000 conventional natural gas wells drilled in 2002,[44] and a total of approximately 65,000 producing gas wells in the province.[45] The future rate of development of new CBM wells is likely to be more rapid. MGV Energy Inc., for example, plans to drill up to 200 CBM wells in 2003.[46]

Coal beds between 150 and 1600 metres deep are currently being explored. Since CBM is licensed in the same way as natural gas, it is not possible to easily identify the locations where development is occurring, unless a company chooses to make its activities public. The approximate location of CBM applications being handled by the Alberta Energy and Utilities Board (EUB) in early spring 2003 is shown in Figure 5.[47] Nexen Inc. is active in CBM

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[41] Approximately one-third (8 of 21) of the applications for development of CBM in March 2003 refer to the Mannville formation. Not all applications specified the coal seams. Information based on application numbers supplied to Sharon Caswell, Rimbey and District Clean Air People by the Alberta Energy and Utilities Board.

[42] EnCana Corporation. 2002. *EnCana's Cash Flow Tops $1 Billion in Third Quarter*. News release, November 5. http://www.encana.com/news_and_views/4_0_20021105_1.shtml See also Canada NewsWire. 2002. *Quicksilver Resources Announces Commercial Coal Bed Methane Development*. News release. October 17; http://www.newswire.ca/releases/October2002/17/c2034.html Quicksilver Resources Inc. is the parent company of MGV Energy Inc. operating in Alberta. In January 2003 EnCana Corporation and MGV Energy Inc. ended their partnership. MGV Energy Inc. plans to produce 15 million cubic feet of gas a day by the end of 2003. Congressional Information Service, Inc. 2003. *Enviroline* 14, no. 4:15.

[43] Companies exploring for CBM include Burlington Resources Canada Ltd. and various smaller companies such as Calver Resources Inc. <http://www.arcfinancial.com/financial/venture/news_releases/22102002.html>; Spirit Energy Corp. <http://www.spiritenergy.ca>; Promax Energy Inc.; and Thunder Energy Inc. Small companies may work with undisclosed larger partners. See Kent Ploegman. 2002. The race is on for coalbed methane. *Edmonton Journal,* November 28:G7. Other companies include Apache, Centrica Canada, Devon Canada, Elk Point Resources, Enerplus Resources, Marathon, North Rock, PennWest, Talisman, Trident Exploration Corp. Some of these names are derived from a list of CBM applications supplied by the Alberta Energy and Utilities Board to Sharon Caswell, Rimbey and District Clean Air People, March 2003.

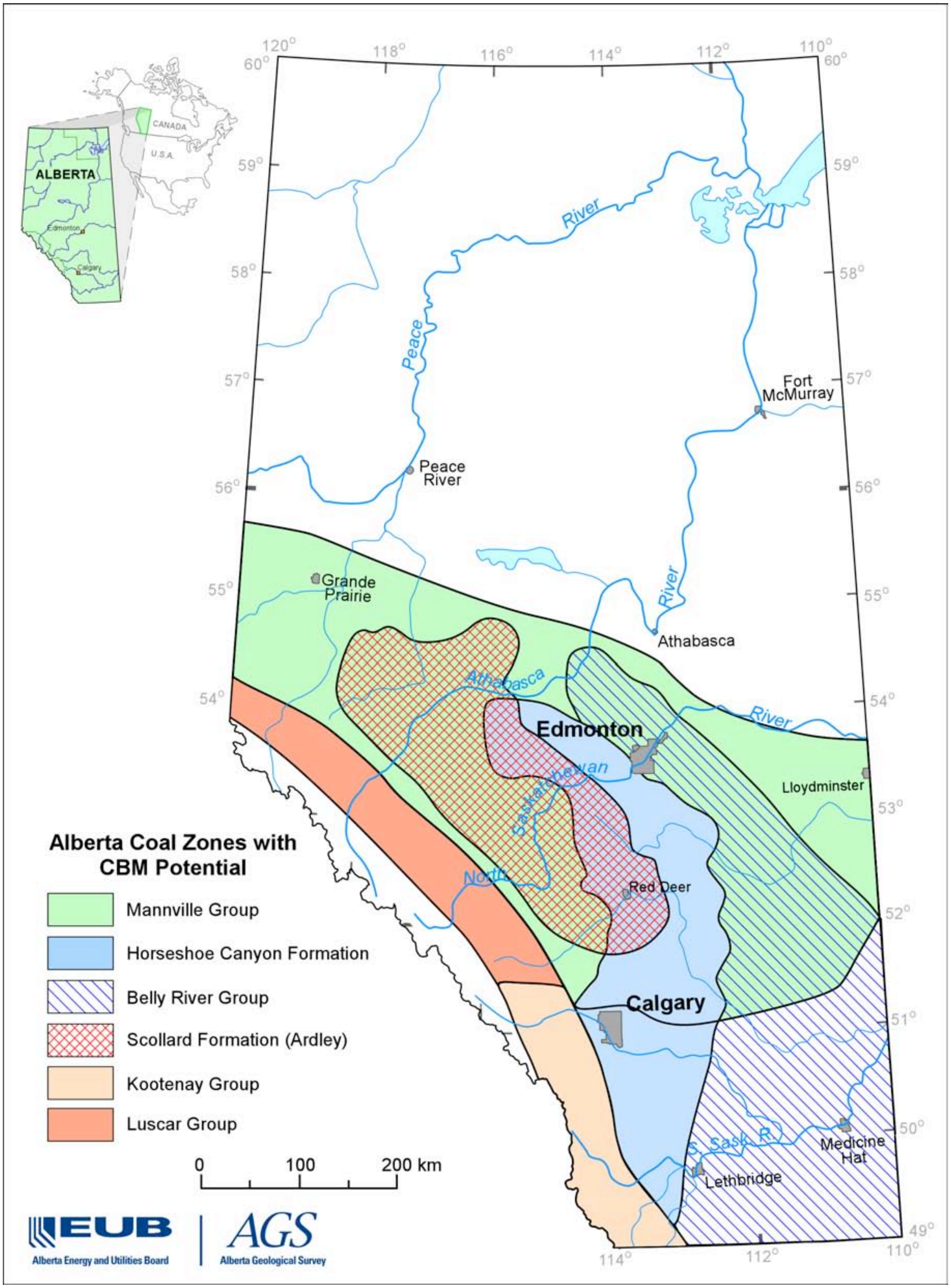
[44] Alberta Energy and Utilities Board. 2003. *Alberta Drilling Activity Monthly Statistics, December, 2002,* Statistical Series 59; http://www.eub.gov.ab.ca/bbs/products/STs/st59/st59-2002.pdf . Over 2000 exploratory natural gas wells and nearly 6,000 development natural gas wells were drilled in 2002.

[45] Alberta Energy and Utilities Board. 2002. *Field Surveillance Provincial Summary 2001/2002*, Statistical Series 57, p. 31; http://www.eub.gov.ab.ca/bbs/products/STs/st57-2002.pdf At the end of the reporting period (March 2002) there were 64,818 producing gas wells in Alberta (that is, conventional natural gas).

[46] Lowey, M. 2003. Coalbed methane issue ignites hope, concerns. *Business Edge*, April 17–23:10. MGV Energy Inc. drilled more than 200 CBM wells in the last two years and plans to drill another 200 this year.

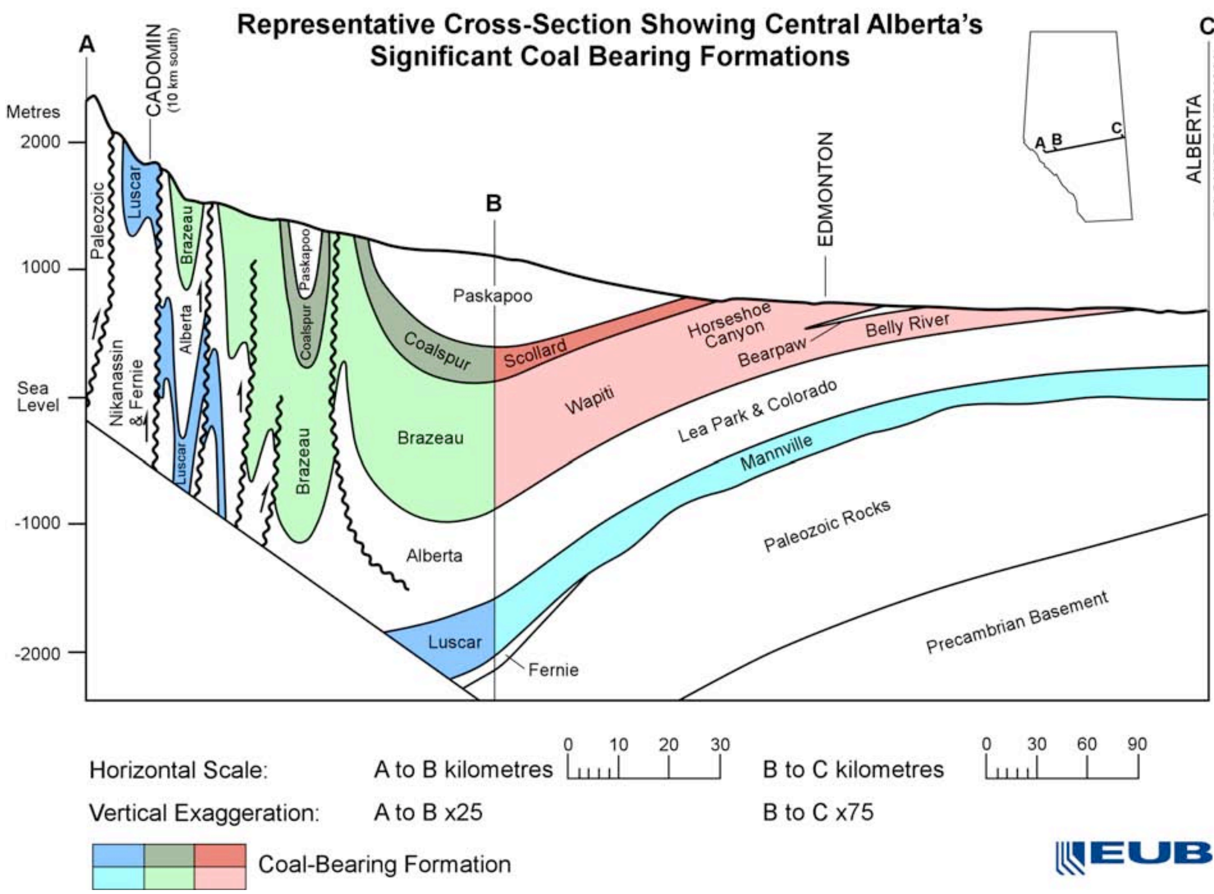
[47] The Alberta Energy and Utilities Board provided most of the application numbers for the CBM wells plotted on this map to Sharon Caswell, Rimbey and District Clean Air People at the end of March 2003. The location of the MGV applications was provided by M. Gatens, MGV Energy Inc. in early May. The base map is provided by the Alberta Energy and Utilities Board, but the wells are plotted by the Pembina Institute to give a general impression of the location of CBM activity in Alberta in spring 2003.

Figure 3: Alberta Coal Zones with CBM Potential



With permission from the Alberta Geological Survey, Alberta Energy and Utilities Board.

Figure 4: Representative Cross-Section Showing Central Alberta's Significant Coal Bearing Formations



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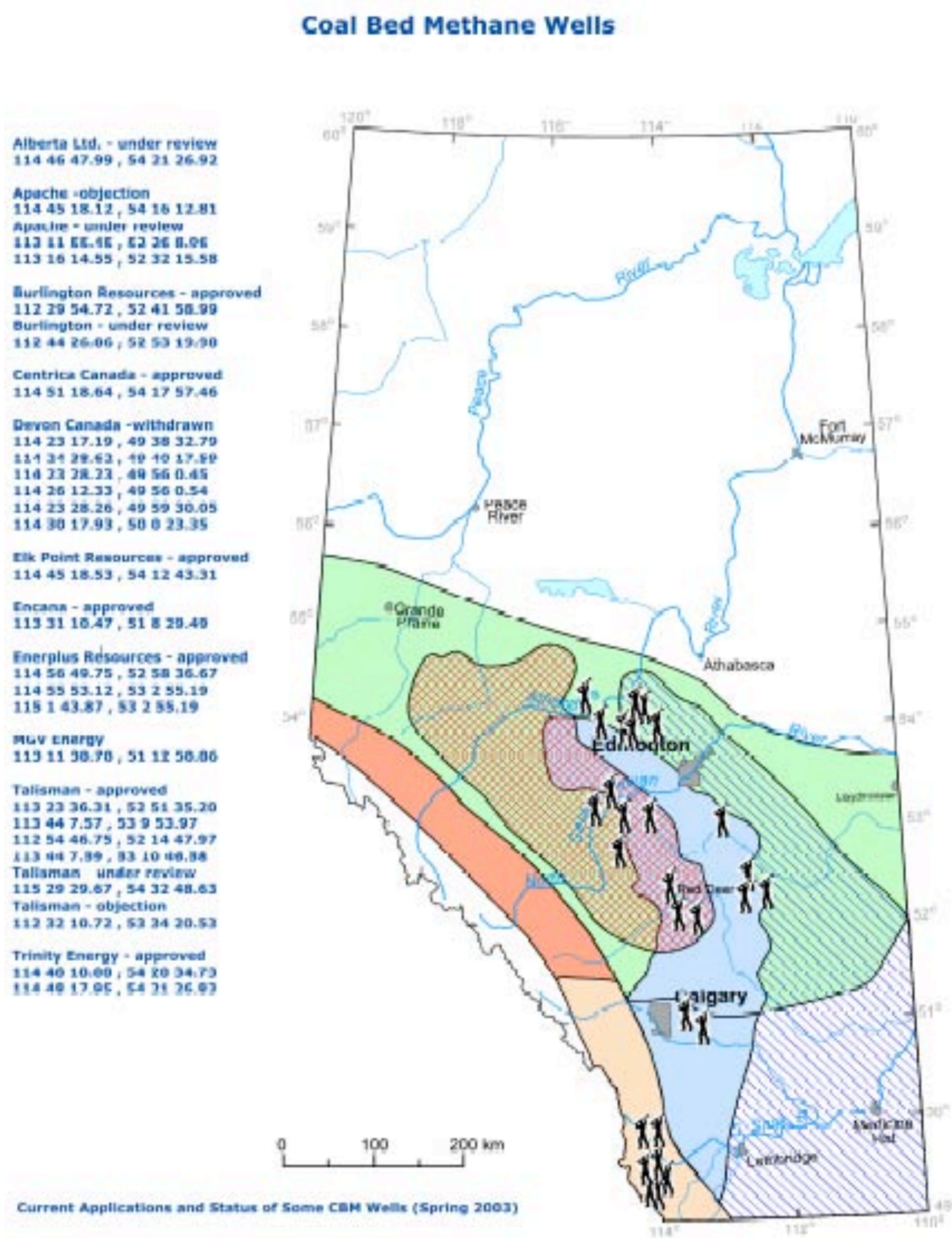
exploration and is involved with several pilot projects. One project, with Trident Exploration Corp., is in the Ft. Assiniboine area, but the location of some pilot projects has not yet been publicly disclosed.[48] Troymin Resources has bought the rights to coal deposits in the Yellowhead and Nordegg regions.[49] Suncor Energy plans a test project in the Red Deer area for enhanced CBM[50, 51, 52] Enhanced CBM recovery is described in Section 6.

[48] M. Simpson, Manager of Coalbed Methane, Nexen Inc., personal communication, February 2003.
[49] Troymin Resources Ltd. 2003. *Coalbed Methane (CBM) Gas Projects;* http://www.troymin.com/s/CoalbedMethane.asp
[50] Suncor Energy. Coal Bed Methane; http://www.suncor.com/bins/content_page.asp?cid=5-53-513
[51] Climate Change Central. 2003. Pilot project advancing technology. *C3 Views* 5, January; http://www.climatechangecentral.com/info_centre/C3Views/default.asp
[52] S. Kaufman, Director of Coalbed Methane, Suncor Energy, personal communication, April 2003.

Figure 5: CBM Well Applications in Alberta, April 2003



This map was compiled by Pembina Institute, using application numbers supplied by EUB and others. Permission to use base map from the Alberta Geological Survey, Alberta Energy and Utilities Board.

The areas in the Prairies that will most likely be explored for CBM in the near future are those where conventional natural gas has already been produced, as the pipelines and other infrastructure are already available.[53] Whether the methane can be economically extracted will depend on the specific characteristics of the formations and their location. The rate of development may also depend on whether the industry receives any incentives. The industry has indicated that they would like some form of assistance in recognition of the costs associated with CBM development.[54]

The rank, or thermal maturity, of the coal generally increases across the Prairies from east to west.[55] Sub-bituminous coal of intermediate rank underlies much of central and southern Alberta, while high-ranking coal is found in deep coal seams in the Rockies (see Figure 2). The most accessible and economic CBM resources are found in the sub-bituminous coals.[56] While large volumes of methane might be found in the high-ranking coals in the Rockies, the geological structures there are complex, coal seams are often deep and the remote location and lack of infrastructure makes extraction expensive.[57] Moreover, the environmental sensitivity of the Rockies means that any proposals for development in the area could meet with higher levels of public concern and potential opposition.

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[53] Some places in BC that do not have access to natural gas may be explored in the near future, partly encouraged by the BC government incentives.

[54] mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta.* Prepared for Alberta Energy, p. 14, 19 and 23. The industry indicated that some form of royalty relief or other favourable fiscal regime should be considered as one of a number of strategies to mitigate CBM specific costs that are additional to those associated with conventional gas; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

[55] The rank of coal depends on its thermal maturity, and thermal maturity usually increases with depth. The ranking of coal from lowest to highest is lignite, sub-bituminous, bituminous, anthracite.

[56] J. Koch, Trident Exploration Corp., personal communication, May 2003.

[57] M. Gatens, MGV Energy Inc., personal communication, April, 2003.

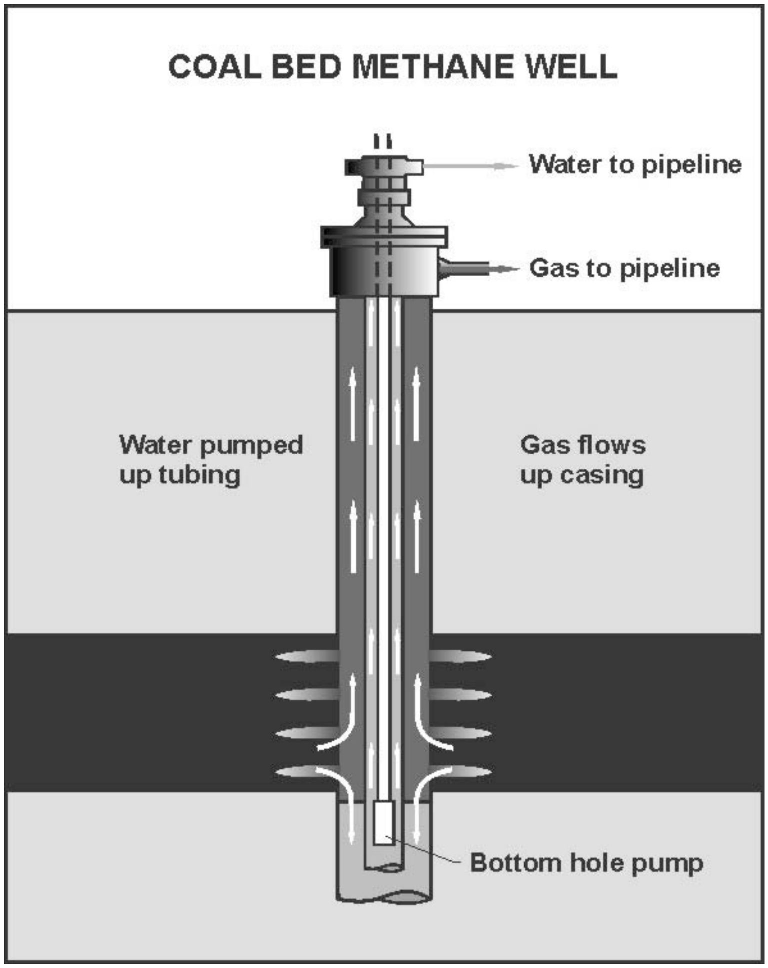
3. How is Coalbed Methane Extracted?

The first step in the development of oil and gas is usually a seismic survey to locate the resource. The location of coal seams in Alberta is well known, so it is unlikely that seismic surveys will be required to find CBM. However, in some cases, companies may carry out seismic testing to provide more detailed information on the structure and continuity of the seams. Companies must obtain a lease and then apply to drill exploratory wells to test the permeability of the coal seams and to estimate the quantity of methane gas that may be recoverable.

When locations suitable for large-scale CBM production have been identified, production wells will be drilled into a coal seam. The initial wells drilled are unlikely to produce sufficient gas until the coal seams have been fracture stimulated.[58] It is necessary to create fractures in the coal seams to intersect tiny, gas-bearing cleats and create pathways through which the methane can flow. This fracturing is usually achieved by pumping a fracturing fluid into the coal seam at pressures sufficient to crack open the rock. When the pressure is high enough, the coal seam will fracture in one direction (wherever the seam is structurally the weakest), enabling the gas to more easily flow to the well. Fracturing fluids are primarily water-based, but they may contain other substances, including acid and small quantities of hydrocarbons.[59] Fracturing may also be carried out using an inert gas, such as nitrogen or CO_2, or foams, which use both water and the inert gases together with a foaming agent.[60, 61, 62] Sand is often added to the fluid as a propping agent. The sand particles penetrate into the seam and become wedged in place, keeping the induced hydraulic fracture propped open, so the gas may flow more easily through the spaces between the particles to the well bore.

[58] For more information on the extraction of coalbed methane see the Canadian Society for Unconventional Gas. 2003. *Natural Gas from Coal: Technical Presentation;* http://www.csug.ca/cbm/dl/NGCtechnical04.16.03.pdf Useful general information is also provided by Ministry of Energy and Mines, British Columbia. 2001. *Coalbed Methane in British Columbia*; http://www.em.gov.bc.ca/mining/geolsurv/coal/coalmeth/CBMpdf.htm
[59] It is not known if hydrocarbons are being used to fracture CBM seams in Canada.
[60] The foaming agent is usually a type of soap, which allows a stable foam to form, giving better viscosity and improved transport of the propping agent, while minimizing the liquids used.
[61] US Environmental Protection Agency. 2002. *Study of Potential Impacts of Hydraulic Fracturing of Coalbed Methane Wells on Underground Sources of Drinking Water*. August 2002 Draft; http://www.epa.gov/safewater/uic/cbmstudy.html
[62] Ministry of Energy and Mines, British Columbia. 2001. *Coalbed Methane in British Columbia,* p. 2; http://www.em.gov.bc.ca/mining/geolsurv/coal/coalmeth/CBMpdf.htm

Figure 6: Coalbed Methane Well



With permission from EnCana Corporation

The next stage in the development of a CBM well depends on whether and how much water is found in the coal seams. Some CBM wells are in areas where the coal strata are dry.[63, 64] In dry seams it is possible to start producing the gas at once.[65] If there is water in the coal seams, however, it must first be pumped out to reduce the reservoir pressure.[66] The water will be typically pumped up the production tubing, while the gas flows up the casing-tubing annulus.[67] The salinity of water found in the coal seams varies and gradually increases with depth. The way in which the water is handled depends on its salinity. In Alberta, water that is defined as "saline" will be disposed by deep well injection into underground formations.[68] Water that is non-saline according to the Alberta Environment definition may be "usable" for watering livestock or irrigation,[69] although there are restrictions on the way in which it can be used, depending on the level of salts. This water may be stored and used or it may be re-injected into an aquifer with similar characteristics.[70] Although many coal seams contain considerable quantities of water, the volume of water varies, even over very short distances. In Alberta the geological strata in general appear to consist of rocks that are less permeable than those in areas of the Powder River Basin in the US, so the volume of water is expected to be less.[71]

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[63] Canadian Association of Petroleum Producers. 2003. *Towards Responsible Development of Coalbed Methane in Canada;* p. 2; http://www.capp.ca/default.asp?V_DOC_ID=843

[64] Canadian Society for Unconventional Gas. 2003, *Natural Gas from Coal: Technical Presentation*, slide 22; http://www.csug.ca/cbm/dl/NGCtechnical04.16.03.pdf

[65] The "dry" coals have been found in some middle depth coals in Alberta, where they are capped with an impervious rock. C. Evans, Alberta Energy and Utilities Board, personal communication, May 2003.

[66] Canadian Association of Petroleum Producers. 2003. *Towards Responsible Coalbed Methane Development in Canada,* p. 1 provides an illustration of a CBM well, compared to a water well; http://www.capp.ca/default.asp?V_DOC_ID=843

[67] The "annulus" is the space between the production tubing (that is, the central pipe) and the hole where it is located, or between two concentric lengths of pipe.

[68] Saline groundwater is defined as water containing over 4,000 milligrams of total dissolved solids per litre (mg/l TDS). *Water Act, Water (Ministerial) Regulation, Alberta Regulation 205/98*, section 1(1)(z); http://www.qp.gov.ab.ca/documents/Regs/1998_205.cfm?frm_isbn=0779717384 Other jurisdictions may have different definitions and different requirements for the treatment of saline water.

[69] Water that is not saline, according to the Alberta Environment definition, is referred to as "usable" water by the Alberta Energy and Utilities Board and Canadian Society for Unconventional Gas. Water with up to 3,000 milligrams per litre of total dissolved solids (mg/l TDS) may be used for watering livestock, while levels between 500 and 3,500 mg/l TDS may be suitable for irrigation (assuming that the sodium adsorption ratio is also satisfactory; see Section 5.3). Non-saline water with very low levels of salinity is sometimes referred to as potable water, meaning, in a general sense, water that could be made fit for consumption. However, the definition of "potable water" in the Environmental Protection and Enhancement Act, section 1(zz), is restricted to water that is supplied by a waterworks system and used for domestic purposes. Potable water should meet the *Guidelines for Canadian Drinking Water*, which apply in Alberta, and contain no more than 500 mg/l TDS. see Table 2 Summary of Guidelines for Physical and Chemical Parameters; http://www.hc-sc.gc.ca/hecs-sesc/water/publications/drinking_water_quality_guidelines/ch4.htm

[70] See Section 5.3 of this paper for more information on the handling of water in CBM wells.

[71] Permeability is a measure of the degree to which rock will transmit fluids and permeable rocks will allow fluids to pass easily through the rock. Rock can hold water in both the pore spaces of the rock and in gaps in the rock (for example, fractures and cleats). For most rock strata, the water coming from fractures represents the most significant component. The permeability of the rocks in the Powder River Basin is between 250 and over 1,000 millidarcies, compared with less than 50 millidarcies in the San Juan and between 0.1 and 10 millidarcies in Alberta. See also mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta*. Prepared for Alberta Energy, p. 27, Table 1; CBM Basin Characteristics; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

In the first few weeks or months of production, only very small amounts of methane will flow from the formation into the well bore and to the surface. It may take several months before a significant quantity of gas is produced. Initially, when volumes are very small, the company may vent the methane to the air, where this is permitted.[72] As the volume increases, the company may flare or incinerate the gas for several weeks or months, until the volume of gas produced reaches a level that makes it economic to install a compressor station and a pipeline to transport the gas to market.[73] If there is an existing pipeline in the area, a company may be able to avoid venting and flaring, by tying in their new well and doing inline testing.[74]

Although in some respects the environmental impacts and risks associated with the development of CBM are similar to conventional natural gas, there are also important differences.[75] These issues are described in detail in Section 5.

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[72] Venting may be permitted in Alberta, but not in BC.

[73] Due to the high methane content of CBM, it is often not necessary for the gas to be treated at a gas plant.

[74] This will not be possible in a "greenfield" site where there is not already a pipeline. In-line testing may require a well site compressor, depending on the local pipeline pressure.

[75] Canadian Society for Unconventional Gas. 2003. *Natural Gas from Coal: Technical Presentation*, slide 15; http://www.csug.ca/cbm/dl/NGCtechnical04.16.03.pdf

4. How is Coalbed Methane Regulated?

The EUB currently regulates CBM extraction in Alberta in the same way as for conventional natural gas, although it has identified ways in which CBM development may differ from that of natural gas.[76] Moreover, a company is required to obtain an approval or licence from Alberta Environment for the dewatering and disposal of water from wells that produce non-saline water.[77] The EUB requirements for industry are set out in various guides and informational letters and the process is explained to the public in a number of brochures and fact sheets.[78] Since the Crown owns the mineral rights under about 80% of land in Alberta, landowners usually are required to grant access to the minerals to a company that has obtained a licence.[79, 80] The EUB requires a company wishing to conduct exploration to consult with the landowner/resident and, in some cases, notify residents within a certain distance. The landowner can raise any concerns about the proposed development with the company and try to reach agreement on issues such as the location of the well, the handling of drilling waste and water, and requirements for flaring. Where the company and landowner are unable to reach agreement on issues, the EUB has a process for appropriate dispute resolution.[81]

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[76] Alberta Energy and Utilities Board, *Coalbed Methane Regulation*, Informational Letter IL 91-11; http://www.eub.gov.ab.ca/BBS/requirements/ils/ils/il91-11.htm The word "regulation" in the title is used in a generic sense; there is no specific regulation that relates to coalbed methane. The Alberta Energy and Utilities Board (EUB) regarded the Informational Letter as an interim measure, while more information was gained about the nature of CBM development in Alberta. Although the general provisions for conventional natural gas apply, the EUB also recognized that CBM development is different. For example, the EUB indicated that a company could apply to keep their exploratory data confidential for a two- or three-year period from the start of an experimental scheme, since it might take longer to develop CBM wells than conventional natural gas wells. The extended confidentiality period for experimental schemes was to enable a company to protect their initial investment for a one- or two-year period. The EUB also indicated that they would be prepared to consider extended flaring of the gas, provided no significant environmental damage occurred. The EUB anticipated that the number of evaluation projects would involve only a few wells and that they would likely have minimal environmental and social impacts (IL 91-11, p. 4).

[77] The Water Act, sections 38 and 51, are applicable to the diversion, and possible use, of non-saline groundwater; http://www.qp.gov.ab.ca/documents/Acts/W03.cfm?frm_isbn=0779711424 A licence is required if the water is to be used. An approval is required when the water is re-injected into an appropriate formation.

[78] Alberta Energy and Utilities Board. 2003. *Guide 56: Energy Development Applications and Schedules* (June 2003), Appendix 11: EUB Brochure *Understanding Oil and Gas Development in Alberta*; http://www.eub.gov.ab.ca/bbs/products/guides/g56.pdf This revised Guide 56 comes into force on October 1, 2003; http://www.eub.gov.ab.ca/BBS/requirements/ils/gbs/gb2003-23.htm See in particular, *Proposed Oil and Gas Development: A Landowner's Guide*, EnerFAQs 8. http://www.eub.gov.ab.ca/bbs/public/EnerFAQs/PDF/EnerFAQs8-Landowner.pdf

[79] Griffiths, M. and T. Marr-Laing. 2001. *When the Oilpatch Comes to Your Backyard: A Citizens' Guide to Protecting Your Rights,* Pembina Institute; http://www.pembina.org/publications_item.asp?id=32 This book explains the process for conventional oil and gas development in Alberta. A revision, that will include information on CBM, is planned for release at the end of 2003.

[80] Harvie, A. 2002. *Legal and Regulatory Aspects of Coalbed Methane Development,* p. 6; http://www.macleoddixon.com/content/eng/lawyers/329_12092.htm

[81] Alberta Energy and Utilities Board. 2000. *Appropriate Dispute Resolution;* http://www.eub.gov.ab.ca/BBS/public/ADR/index.htm

If a company has to apply to Alberta Environment for a licence or approval for dewatering non-saline water, they will be required to provide information on the baseline hydrological and hydrogeological conditions.[82] Alberta Environment uses this information to determine potential impacts and decide on the appropriate requirements for water management, which is done on a case-by-case basis.[83] They will also take into consideration any input from the public.[84] The licence or approval may contain conditions, including requirements to minimize the effects of dewatering and the installation of monitoring wells to measure the impacts. Gas wells are exempt from the environmental impact assessment (EIA) process and at present there is no formal process to examine the cumulative impact of dewatering from multiple wells.[85]

There is one area where the regulation of CBM wells should be amended, or where there should be a requirement for the EUB to formally consult with Alberta Environment. This concerns requirements for the construction and completion of CBM wells to prevent contamination of non-saline aquifers. The EUB regulations require casing/cementing of a well to below the base of groundwater protection to protect non-saline groundwater.[86] EUB regulations also require the segregated production of different pools. However, a company may apply to vary from this regulatory control and produce from more than one zone, resulting in the co-mingling of production in the well bore. Historically, these applications have involved two or more zones, some of which may contain saline water. If the conservation, environmental and other potential impacts are properly addressed, approval of co-mingled production may be granted.[87]

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[82] Alberta Environment. 2003.*Groundwater Evaluation Guideline (Information Required When Submitting an Application under the Water Act);* http://www3.gov.ab.ca/env/water/Legislation/Guidelines/GroundwaterEvaluation.pdf

[83] While all water below the base of groundwater protection (that is saline water, with a salinity greater than 4,000 mg/l TDS) must be disposed of down a deep well, water above the base of groundwater protection (that is, with a salinity less than 4,000 mg/l TDS) may be used, discharged or re-injected, depending on the level of salinity and local conditions. See also Sections 5.3 and 7.4.4.

[84] When a company applies for an approval or licence, they must provide a public notice (usually in the local newspaper), as required by the Water Act, section 108; http://www.qp.gov.ab.ca/documents/Acts/W03.cfm?frm_isbn=0779711424 If the application is advertised, members of the public can submit written statements of concern to the director under the Water Act (Water Act, section 109). The director will then usually ask the company to contact all those who filed a statement of concern and to provide information and attempt to resolve the issues. Members of the public who have submitted a statement of concern under section 109 and who can show they are "directly affected" by the project, may appeal any decision that director makes with respect to issuing an approval or licence. The appeal is made to the Environmental Appeal Board, as set out in section 109 of the Water Act.

[85] Alberta Environmental Protection and Enhancement Act, Regulation 111/93, *Environmental Assessment (Mandatory and Exempted Activities) Regulation*. Schedule 2 (e); http://www.qp.gov.ab.ca/documents/Regs/1993_111.cfm?frm_isbn=0773287426 The drilling, construction, operation or reclamation of an oil or gas well is exempt from the Environmental Impact Assessment process as set out in Part 2, Division 1 of the Alberta Environmental Protection and Enhancement Act.

[86] Alberta Energy and Utilities Board. 1997. *Guide 8: Surface Casing Depth Minimum Requirements*, Appendix 1, p. 3, reference to the Oil and Gas Conservation Regulations, section 6.080. http://www.eub.gov.ab.ca/bbs/products/guides/g08.pdf If the surface casing (which is cemented to the surface) does not provide protection to the base of groundwater protection, then the production casing must be cemented to the surface to ensure that groundwater protection is in place.

[87] Saline and non-saline water zones may not be co-mingled and must be kept isolated to protect non-saline water.

Currently, the EUB reviews applications for co-mingling and, if it involves a non-saline water zone, the staff will direct an applicant to discuss the water issue with Alberta Environment. However, at the time of writing this is not a formal requirement in EUB Guide 65, which documents co-mingling application requirements.

It is noted that co-mingling may result in fewer surface land conflicts as it would directly reduce proliferation of wells. However, if a CBM well is completed across the base of groundwater protection,[88] co-mingling might occur between the saline water below and the better quality water above.[89] Consequently, according to the Water (Ministerial) Regulation, non-saline groundwater could be degraded in time if CBM wells are not properly constructed.[90]

Potential mixing of different water qualities is an important consideration that requires close cross-ministry co-ordination and detailed assessment to minimize future problems. A CBM well completed in the non-saline water interval should be treated in much the same way as a water well. When a water well is drilled, the Water Act requires it to be constructed in such a manner that it does not result in multiple aquifer completions, so there is no concern about water (or gas) crossing from one aquifer to another.[91]

When CBM development in Alberta was first contemplated, the EUB indicated that some tests of CBM production were necessary as a basis for long-term regulatory policies. At that time, not enough was known about CBM in Alberta to determine what those policies should be.[92] The Alberta government recognizes that new guidelines are required to deal with issues specific to CBM.[93] The EUB is introducing a separate code for classifying CBM wells, and a few changes specific to CBM have been incorporated into revised and draft EUB guides that deal with flaring and public consultation requirements.[94] Alberta Energy has initiated a review and cross-government consultation process to determine how existing rules should be modified

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[88] The base of groundwater protection is defined by groundwater with 4000mg/l TDS.

[89] Mixing of water or gas from two zones could happen when the pressure in the lower zone is higher than that in the upper zone. As a result, the gas or water will rise through the pipe and could "escape" into the upper zone.

[90] Some sort of buffer may be required to prevent encroachment of production activity near the salinity cut-off area.

[91] *Water Act, Water (Ministerial) Regulation, Alberta Regulation 205/98*, section 47(g); http://www.qp.gov.ab.ca/documents/Regs/1998_205.cfm?frm_isbn=0779717384
The well must be sealed for the full length of the annulus from the ground surface to the top of the aquifer. A CBM well that is drilled into a non-saline water aquifer is essentially the same as a water well. It should thus be required to meet the same standards. It should not be allowed to have multiple zone completions. This means that a well should not be drilled from one aquifer to the next. If one aquifer is depleted, a new well bore should be drilled to a deeper aquifer, with complete casing through the higher aquifers.

[92] Alberta Energy and Utilities Board. 1991. *Coalbed Methane Regulation*, Informational Letter IL 91-11, p. 4; http://www.eub.gov.ab.ca/BBS/requirements/ils/ils/il91-11.htm

[93] See, for example, Alberta Energy. 2002. *Proposal for Continuing Petroleum and Natural Gas Agreements via Coalbed Methane in Alberta 2002.* Prepared by Tenure Business Unit, Resource Land Assess Business Unit, Oil Development Division, Alberta Energy. This document is still in draft and will be revised as new information becomes available.

[94] Alberta Energy and Utilities Board. 2003. *Guide 56: Energy Development Applications and Schedules* (June 2003) identifies CBM as a separate well type that has its own code; see Section 7.1 and Table 7.7; http://www.eub.gov.ab.ca/bbs/products/guides/g56.pdf , This revised Guide 56 comes into force on October 1, 2003; http://www.eub.gov.ab.ca/BBS/requirements/ils/gbs/gb2003-23.htmAlso, *Draft Guide 60: Upstream Petroleum Industry Flaring, Incinerating, and Venting,* Section 8.8 refers to CBM; http://www.eub.gov.ab.ca/bbs/products/guides/g60/g60-draft.pdf.

for CBM development.[95] In the initial, internal phase, the government is gathering information that can be used to evaluate CBM developments. An external consultation phase is planned to involve industry, landowners, environmental organizations and other stakeholders.[96] In BC the Oil and Gas Commission released draft guidelines for CBM development in 2002.[97]

The ownership of mineral rights is another issue related to CBM regulation. Under the Mines and Minerals Act, where the Crown owns the mineral rights, natural gas reserves are leased separately from coal reserves. The government has regulated CBM in the same way as natural gas and the rights to CBM have usually gone to those who have rights to the natural gas. However, this was not written into legislation until the Mines and Minerals Act was amended in spring 2003.[98]

On the 20% of land in Alberta where owners have freehold mineral rights, ownership of the rights to CBM may be controversial.[99] Canadian Pacific Railways (CPR) originally acquired rights to minerals over a large area of Western Canada. When the mineral rights were transferred to settlers, CPR often retained the rights to the coal. No mention was made of CBM. The courts in Alberta have not directly dealt with ownership of CBM, although other recent decisions could be relevant. [100]

The government in BC also passed legislation in spring 2003, to confirm the longstanding provincial policy, that CBM is natural gas and belongs to the holder of the natural gas rights.[101] They thus hope to end the uncertainty around this issue and the threat of legal challenges.

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[95] Alberta Energy. 2002. *Alberta Examines the Potential for Coalbed Methane Development*. News release, October 22, Backgrounder, p. 1; http://www.gov.ab.ca/acn/200210/13392.html While Alberta Energy is leading the process, the Alberta Energy and Utilities Board, Alberta Agriculture, Food and Rural Development, Alberta Environment, Alberta Innovation and Science, and Alberta Sustainable Resource Development are participating in the review and consultation. This process will determine whether existing policies and regulations are appropriate for responsible development of CBM or if changes should be made. S. Rauschning, Alberta Energy, personal communication, May 2003.

[96] A pre-consultation process with key stakeholders will commence in fall 2003, to identify and prioritize issues, including environmental concerns associated with CBM development. S. Rauschning, Alberta Energy, personal communication, June 2003. See also Alberta Energy. 2003. *Coalbed Methane/Natural Gas from Coal;* http://www.energy.gov.ab.ca/com/Gas/NGC/default.htm

[97] BC Oil and Gas Commission. 2002. *Guidelines for Coalbed Methane Projects in British Columbia;* *http://www.ogc.gov.bc.ca/documents/guidelines/Coalbed%20Methane%20Guidelines.pdf* The Draft Guidelines were released on October 21, 2002.

[98] The fact that rights to the coal do not usually include rights to the coalbed methane has been clarified in the *Energy Statutes Amendment Act, 2003*, section 15, which amends section 67 of the *Mines and Minerals Act*, by including the words "coalbed methane." At the time of writing the Energy Statutes Amendment Act had not been proclaimed. The only exception is where a coal lessee is given special ministerial approval to recover the gas for safety or conservation reasons (*Mines and Minerals Act*, section 67(2)).

[99] Harvie, A. 2002. *Legal and Regulatory Aspects of Coalbed Methane Development,* p. 2; *http://www.macleoddixon.com/content/eng/lawyers/329_12092.htm*
See also mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta.* Prepared for Alberta Energy, p. 34;
http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

[100] Freeholders Association. 2003. *Newsletter.* May 6, p. 5–7; http://www.fhoa.ca

[101] *Coalbed Gas Act*, S.B.C., 2003, c.18; http://www.legis.gov.bc.ca/37th4th/3rd_read/gov16-3.htm A backgrounder issued in relation to the BC Ministry of Energy and Mines Information Sessions, January 20–23,

5. What are the Potential Environmental Impacts of Coalbed Methane Extraction?

Landowners and environmental organizations in Alberta have expressed concerns about CBM development and some have requested a moratorium until the public has been properly consulted and regulations and guidelines are in place to deal specifically with CBM.[102] Many of the concerns stem from experience with environmental impacts associated with CBM development in the US, the potential dramatic expansion of CBM development in Canada, and the failure of the Alberta government to undertake public consultation prior to authorizing the commercial development of CBM. Landowners and conservation groups are concerned that areas that have already been detrimentally affected by prior oil and gas development will be further impacted by CBM development.

Since the development of CBM in Canada is new, it is natural to look at experience in the US to learn about the potential environmental impacts of CBM development.[103, 104] Concerns in the US have focused on the extensive areas covered by CBM leases and the high density of wells and associated land impacts.[105] The large volume of water produced during the development phase is a major issue in parts of the US, as is the length of the period of flaring that may

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2003, noted, with respect to the coalbed gas bill, that the US Supreme Court had found that federal coal rights did not include coalbed gas. US state court decisions have gone both ways.

[102] Rimbey and District Clean Air People wrote to Neil McCrank, Chairperson, EUB, and Minister of Environment Lorne Taylor, April 1, 2003, requesting a moratorium on CBM development. They stated that "The AEUB should not consider any new applications to develop CBM until guidelines specifically designed for coalbed methane access and production have been developed by the AEUB and Alberta Environment." They expressed concerns with respect to dewatering and the contamination of aquifers, land fragmentation, methane leaks, venting and flaring of methane gas, noise associated with compressors and poorly defined plans relating to produced non-saline water. The Alberta Environmental Network expressed their concerns about the potential long-term environmental impacts to the Alberta Energy and Utilities Board in a meeting on April 11, 2003. They wanted assurance that there would be no relaxation of guidelines or policies to accelerate CBM development and no "grandfathering" of current projects when new regulations or policies are introduced. West Coast Environmental Law has alerted citizens to potential impacts of CBM in BC in their 2003 publication, *Coalbed Methane: What is it? What Could it Mean for BC?;* http://www.wcel.org/wcelpub/2003/13928.pdf

[103] mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta.* Prepared for Alberta Energy. United States Basin Experience, p. 24–45; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

[104] The Powder River Basin Resource Council identifies potential issues on their Web site at http://www.powderriverbasin.org/index.htm The Oil and Gas Accountability Project, based in Colorado, provides information on the Coalbed Methane Project, which is a network of 16 organizations across the US; http://www.OGAP.org See also Natural Resources Law Center, Colorado School of Law. 2002. *Coalbed Methane Development in the Intermountain West: A Primer;* http://www.colorado.edu/Law/centers/nrlc/pubs.htm

[105] The US Bureau of Land Management conducted Environmental Impact Assessments of oil and gas developments in the Powder River Basin in Wyoming and in the entire state of Montana. These were published in January 2003. The assessments include the impacts of CBM development. See *Final Environmental Impact Statement and Proposed Plan Amendment for the Powder River Basin Oil and Gas Project;* http://www.wy.blm.gov/nepa/prb-feis/; *Final Statewide Oil and Gas Environmental Impact Statement and Proposed Amendment of the Powder River and Billings Resource Management Plan;* *http://www.mt.blm.gov/mcfo/cbm/eis/index.html* The *Record of Decision and Resource Management Plan Amendments for the Powder River Basin Oil and Gas Project* was issued in April 2003; http://www.prb-eis.org/PRB%20ROD.pdf and http://www.prb-eis.org/Documents.htm

precede commercial capture of methane gas. The extent and nature of problems may be different in Canada, as Canada and the US have regionally specific geological conditions, as well as different land tenure systems and CBM regulations. However, it is important to be aware of these issues, so that potential impacts in Canada can be evaluated and minimized.

5.1 Extensive mineral leases

CBM wells are generally less productive compared to conventional gas wells.[106] Therefore companies seek to ensure that they obtain extensive, contiguous mineral leases for CBM development upon which they can drill enough wells to make a project economic. Since it may take as many as 10 to 20 wells to extract the amount of gas that could be produced by two or three natural gas wells, these extensive mineral leases may translate into widespread surface development in an area.[107] In the US a land base of at least one or two townships is considered desirable for a CBM project.[108]

5.2 Density of wells

The standard well spacing in Alberta is one gas well per section (640 acres)[109] and one oil well per quarter section (160 acres). To obtain the maximum recovery of CBM a company may want to drill wells at a higher density.[110] The density requested will depend on the specific geological conditions. The EUB allows a company to apply for closer well spacing and eight wells per section (that is, one well per 80 acres) or more are sometimes requested to improve the recovery of conventional natural gas from shallow zones. This density may be requested for CBM wells.

The EUB spacing requirements apply to a specified geological formation or zone, not to the number of wells allowed on the surface.[111] The intention of the EUB spacing requirements is to

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[106] Recent CBM wells in Alberta yield 30,000 to 250,000 cubic feet of methane per day (cfd); that is 850 to 7,100 m^3/day. See EnCana Corporation. 2003. *EnCana Cash Flow Tops $ 1 Billion in Third Quarter.* News release. November 5; http://www.encana.com/news_and_views/4_0_20021105_1.shtml An "average" conventional gas well will usually yield 15,000 to 30,000 m^3/day or more, thus approximately 2 to 35 times the volume of the EnCana wells. However, some CBM wells, for example in the San Juan Basin, produce as much as efficient conventional gas wells.

[107] The impacts may be less in areas of dry CBM wells.

[108] mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta.* Prepared for Alberta Energy, p. 36, footnote 28: "The U.S. producers interviewed suggest land bases of 20,000 to 50,000 acres were preferable for CBM projects, for economic and competitive reasons."; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

[109] *Alberta Regulation 151/71, Oil and Gas Conservation Act, Oil and Gas Conservation Regulations*, sections 4.020(2) and 15.160; http://www.qp.gov.ab.ca/documents/Regs/1971_151.cfm?frm_isbn=0773293396 A section of land is 640 acres.

[110] mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta*. Prepared for Alberta Energy. Table 1: CBM Basin Characteristics, p. 27, shows well spacing of one CBM well per 40, 80, 160 or 320 acres in different US basins; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

[111] Alberta Regulation 151/71, Oil and Gas Conservation Act, Oil and Gas Conservation Regulations, sections 4.010(1) states: "The drilling spacing unit for a well is the surface area of the drilling spacing unit and (a) the subsurface vertically beneath that area, or (b) where the drilling spacing unit is prescribed with respect to a specified pool, geological formation, member or zone, the pool, geological formation, member or zone vertically beneath that area."; http://www.qp.gov.ab.ca/documents/Regs/1971_151.cfm?frm_isbn=0773293396

regulate the exploration of the underground resources, not to limit the surface impacts. Multiple wells targeting different zones may be placed adjacent to each other. A company may purchase the rights to several zones or formations, but the right to different formations may be owned by different companies. If so, each company could have their own wells on separate pads. The EUB has discretion to determine exactly what spacing will be allowed for each formation (and hence the surface impact).[112]

Since CBM wells are regulated in the same way as natural gas wells, if a company wishes to exceed the standard density, they request special approval from the EUB.[113] This entails discussing the proposed spacing with people who are directly affected by it and reporting their concerns to the EUB.

The higher density of wells leads to greater land disturbance not only from the construction of well pads and access roads but also from the increased density of pipelines connecting each well. This can limit land use by farmers and, in wilderness areas, cause the loss or fragmentation of habitat and make wildlife more vulnerable to predators and hunters. Directional drilling (drilling several wells from a central well pad) has been used to extract CBM in some areas in the US. In Alberta, at least two companies are experimenting with directional drilling, with several wells being accessed from one central pad.[114, 115] If this proves technically successful and is still economic, companies may be able to limit the number of well pads per section. Whether directional drilling will be feasible may depend partly on the geological structure and on the depth of the seams being accessed.[116]

At some locations in the US wells have been drilled at considerably higher densities than is normal for natural gas wells, with the density depending on the characteristics of a particular area.[117] In the Powder River Basin in Wyoming the maximum well density used to be about one well per 40 acres, although in 2000, the regulations were changed to set a limit of two wells

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[112] There may be ten or more formations in an area. The theoretical number of wells on a section could thus be very high. The EUB decides what is appropriate; no maximum limits are specified in the regulations.

[113] Alberta Energy and Utilities Board. 2000. *Guide 65: Resources Applications for Conventional Oil and Gas Reservoirs,* pp. 4, 6, 20, 59–64, especially p. 63; http://www.eub.gov.ab.ca/BBS/requirements/Guides/g65.htm A company requesting closer well spacing must provide the EUB with a statement indicating whether the surface owners or occupants in the area of application have been contacted about the proposed spacing change. If owners and occupants have been contacted, the company must present the EUB with a summary of their views. If the company does not do this, the EUB will provide notice to those who may be adversely affected and invite them to submit comments or objections. There is no mandatory requirement for any public announcement. See also Alberta Regulation 151/71, Oil and Gas Conservation Act, Oil and Gas Conservation Regulations, sections 4.040(3); http://www.qp.gov.ab.ca/documents/Regs/1971_151.cfm?frm_isbn=0773293396

[114] EnCana is trying directional drilling as a pilot. C. Cline, personal communication, June 2003.

[115] Centrica is experimenting with drilling three wells from a central pad. M. Simpson, Manager of CBM for Nexen Inc., personal communication, February 2003.

[116] Directional wells are not suitable for accessing shallow CBM gas, as it is not possible to get enough spacing between wells drilled from the same pad in a short vertical distance to effectively produce from a wide zone. Horizontal drilling (extending from a vertical well) will probably work best in thick coal seams.

[117] mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta.* Prepared for Alberta Energy, Table 1: CBM Basin Characteristics, p. 27; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

per quarter section (an average of one well per 80 acres).[118] In the San Juan Basin, in northwest New Mexico and southwest Colorado, well density used to be one well per half-section (that is, one per 320 acres), but regulatory approval for an additional well on the majority of the spacing units in Colorado was granted in 2001, and is expected to be approved soon for most of the New Mexico portion of the basin.[119]

5.3 Dewatering of coal seams

The dewatering of coal seams is often necessary prior to the production of CBM. The quantity and quality of water varies from one coal formation to another.[120] The quantity of water depends on the cleat volume and the permeability of the coal seams. Some of the coal seams investigated in Alberta to date have tight cleats,[121] and so contain relatively small volumes of water.[122] In one region of Alberta, the coal seams are dry,[123] but it is not known how representative this will be for seams across Alberta.

Where the coal seams are permeable, the volume of water varies considerably, as does the ratio of water to gas.[124] Experience from the US indicates that it can take up to 12 months or more before commercial volumes of gas are produced.[125] With pumping, the volume of produced water will gradually decline and the volume of gas will increase. CBM wells may produce from 5 to 100 cubic metres of water a day for several months or more.[126, 127] This variability arises as

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[118] mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta.* Prepared for Alberta Energy, p. 35; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

[119] D. Cox, Trident Exploration Corp., personal communication, June 2003.

[120] Non-saline water is generally found closer to the Earth's surface than is saline water. For the most part, the concentration of total dissolved solids (TDS) (and thus the salinity of the water) increases with depth, as saline water is of greater density than non-saline water. Some types of bedrock, such as sandstones, are relatively permeable and capable of transmitting significant quantities of water. In Alberta sandstone aquifer flow systems tend to be isolated from other regional flow environments by rocks of very low permeability, such as shale. This separation may prevent water movements between aquifers.

Non-saline water is used in this report to refer to water that is not saline according to the Alberta definition of saline groundwater.

[121] Cleats are tiny cracks in the coal.

[122] Permeable rocks allow fluids to pass easily through the rock. Permeable rocks can hold water in the gaps in the rock (that is, in the cleats in the rock). The permeability of the rocks in the Powder River Basin is between 250 and over 1,000 millidarcies, compared with less than 50 millidarcies in the San Juan and between 0.1 and 10 millidarcies in Alberta. See also mHeath & Associates. September 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta.* Prepared for Alberta Energy, Table 1: CBM Basin Characteristics, p. 27; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

[123] Wells drilled by MGV Energy Inc. in the Western Palliser block, east of Calgary, at between 200 and 800 metres deep have produced as little as zero to five litres of water a week. Dry coals have been identified in the Horseshoe Canyon formation from just south of Edmonton to as far south as Vulcan. M. Gatens, MGV Energy Inc., personal communication, April 2002. By April 2003, MGV had drilled more than 200 wells, but the total volume of produced water was 8,000 litres. G. Robinson, MGV Energy Inc., cited in *Enviroline* 14:5&6, p. 6.

[124] US Geological Survey. 2000. *Water Produced with Coal-Bed Methane,* USGS Fact Sheet FS-156-00; http://pubs.usgs.gov/fs/fs-0156-00/fs-0156-00.pdf

[125] Alberta Energy. 2002. *Proposal for Continuing Petroleum and Natural Gas Agreements via Coalbed Methane in Alberta 2002.* Prepared by Tenure Business Unit, Resource Land Assess Business Unit, Oil Development Division, Alberta Energy, p. 5. This document is still in draft and will be revised as new information becomes available.

[126] BC Ministry of Energy and Mines, *Coalbed Methane in British Columbia*, p. 7: "A CBM well may produce from 50 to over 1,000 barrels of water per day";

the geological conditions, such as cleat volume, permeability of the coal, and regional hydrodynamics, differ from one formation to another. In general the permeability of the strata declines with depth.[128] It is difficult to predict the volume of water that a well will produce without proper testing as permeability may vary over short distances.

The coal strata targeted by a CBM well will normally be at a greater depth than the freshwater aquifer being used by the landowner. Often water wells are less than 100 metres deep, whereas coal seams are being explored for CBM wells at between 150 and 1600 metres. There may be several different geological strata between the CBM and the freshwater aquifer. Provided the aquifers are isolated, dewatering the coal strata should not impact the shallow aquifer being used by the landowner. However, in some cases there may be interconnectivity between different aquifers and dewatering from one aquifer may result in a lowering of water levels in another aquifer nearer the surface. Thus landowners in the vicinity of CBM operations are naturally concerned that the dewatering of aquifers may affect their water supply and force them to drill more water wells or find alternative sources of water. Since each CBM project may require up to eight wells per section or more,[129] and this density of wells may extend over considerable areas of land, the effect of dewatering could be felt over a wide area. In addition to affecting groundwater users, a decline in the water table in an area can lead to the drainage of wetlands and reduced flows in streams and rivers. These effects may be long term.

One of the challenges associated with the extraction of CBM in the US concerns ways to dispose of the water produced through the dewatering process.[130, 131] In the Powder River Basin in Wyoming the average well produces over 40 cubic metres/day, while in the older San Juan field it averages around four cubic metres/day.[132] An average well in the Powder River Basin could fill more than four Olympic swimming pools in a year.[133] Dewatering coal seams with several wells per section results in significant quantities of water being removed. In some

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http://www.em.gov.bc.ca/mining/geolsurv/coal/coalmeth/CBMpdf.htm This is equivalent to between 6 and 115 cubic metres. One barrel is approximately 115 litres or 0.115 cubic metres. See also US Geological Survey. 2000. *Water Produced with Coal-Bed Methane,* USGS Fact Sheet FS-156-00. The *average* volume of water produced by CBM wells in different basins in the US ranges from 25 to 400 barrels per day; http://pubs.usgs.gov/fs/fs-0156-00/fs-0156-00.pdf This is equivalent to 1,050 to 16,800 gallons, or 4 to 63 cubic metres.

[127] A cubic metre is equivalent to approximately 220 Canadian gallons or nearly 265 US gallons.

[128] Bachu, S. 2002. *Flow of Formation Water and Coal Permeability: Indicators of Exploration Target Areas for CBM in Alberta's Upper Cretaceous-Tertiary Strata*. Alberta Geological Survey. Fourth Annual Unconventional Gas and Coalbed Methane Conference, October 23–25, 2002. Calgary, Alberta, Petroleum Technology Alliance Canada and Canadian Society for Unconventional Gas.

[129] This spacing is similar to conventional shallow natural gas well spacing, although the standard spacing for natural gas wells is one well per section. See Section 5.2 of this report for more on well spacing.

[130] Harvie, A. 2002. *Legal and Regulatory Aspects of Coalbed Methane Development* p. 16–19*;* http://www.macleoddixon.com/content/eng/lawyers/329_12092.htm

[131] US Geological Survey. 2000. *Water Produced with Coal-Bed Methane,* USGS Fact Sheet FS-156-00; http://pubs.usgs.gov/fs/fs-0156-00/fs-0156-00.pdf

[132] US Geological Survey. 2000. *Water Produced with Coal-Bed Methane,* USGS Fact Sheet FS-156-00; http://pubs.usgs.gov/fs/fs-0156-00/fs-0156-00.pdf
See also mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta.* Prepared for Alberta Energy, p. 31;
http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

[133] A standard Olympic pool measures 50 metres long, 23 metres wide, and 3 metres deep, or 3,450 cubic metres in volume. At a rate of 40 cubic metres a day, it would take 86.25 days to fill one Olympic-sized swimming pool.

locations in the Powder River Basin the way in which this water has been handled has damaged the environment.[134]

In the Powder River Basin the majority of CBM wells produce water with less than 5,000 mg/l total dissolved solids. The water is usually discharged or stored on the surface; in some locations with clay soils the minerals in the water have reacted with the clay to damage the soil structure. Although the volume of water in the coal seams declines as pumping proceeds, the quality of water tends to deteriorate, with increasing concentrations of various minerals and heavy metals. Where water is stored in pits, the concentration of minerals accumulates. When timing the surface discharge of large quantities of water, the natural seasonal characteristics of the hydrologic cycle should be taken into consideration to reduce impacts on the natural system.[135]

In Alberta the coal seams generally have far lower permeability than the coal seams found in the Powder River Basin which suggests that the volume of produced water will be less. In addition, Alberta's guidelines for handling water with different levels of salinity appear to be more stringent than in some parts of the US.

Where the water that would be removed from the coal seam is non-saline, a company is required to obtain a licence or approval from Alberta Environment.[136, 137] There will usually be a public notice of the application.[138] Alberta Environment requires the company to assess the environmental risks before issuing an approval for dewatering non-saline aquifers. However, it is difficult for Alberta Environment to estimate long-term, cumulative impacts by reviewing applications on a well-by-well basis. Alberta Environment does not have sufficient data on aquifers and river basins to determine the cumulative environmental impacts of extracting water from coal seams for CBM projects[139] and there is no provision for a formal EIA of CBM projects in Alberta.

Alberta Environment intends to evaluate its policy, based on current experience. It is not yet known if or how the potential cumulative impacts of dewatering an extensive area will be

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[134] J. Morrison, Powder River Basin Resource Council, personal communication, April 2003. Note: In the US salinity is often reported in terms of the electrical conductivity (EC) of the water, instead of in total dissolved solids (TDS). To convert EC to an approximate TDS in milligrams per litre, multiply the EC in mmhos/cm by 640; http://www.montana.edu/wwwpb/ag/wen_salt.html

[135] See reports on CBM and water issues at http://www.powderriverbasin.org/prbrc/cbm_monitor_page1.htm See in particular, L. Munn. 2002. *CBM, Water and Soils* and the section that cites S. Tyler, entitled *Hydrological Impacts of CBM Inadequate.*

[136] Alberta Environment. 2003. *Water Act Fact Sheet, Approvals and Licences;* http://www3.gov.ab.ca/env/water/Legislation/FactSheets/GeneralInfo.pdf and Alberta Environment. 2002. *Water Act, Fact Sheet, Temporary Diversion of Water;* http://www3.gov.ab.ca/env/water/Legislation/FactSheets/TemporaryDiversion.pdf

[137] Alberta Environment. 2001. *Administrative Guide for Approvals to Protect Surface Water Bodies Under the Water Act; http://www3.gov.ab.ca/env/water/Legislation/Approvals_Licences/ApprovalsAdminGuide.pdf* The definition of "water body" includes aquifers.

[138] Alberta Environment. 2003. *Groundwater Evaluation Guideline (Information Required when Submitting an Application under the Water Act);* http://www3.gov.ab.ca/env/water/Legislation/Guidelines/GroundwaterEvaluation.pdf

[139] Hui, E., Director, Alberta Environment Drinking Water Branch, 2003. Presentation given at a conference on "Understanding the Business of Coalbed Methane." Conference Board of Canada. *Enviroline* 14:4, p.11.

reviewed before granting approvals for dewatering. Current requirements are being reviewed by Alberta Environment to address this issue.[140] In the US, extensive cumulative impact studies have been required prior to approval for large-scale CBM developments on federal land, indicating that the government thinks such assessment is important.[141]

In theory, there are several ways in which water from coal seams can be managed:

- discharge to rivers, streams, ponds, lakes or wetlands
- use for crops, livestock, etc.
- re-injection to help recharge non-saline groundwater aquifers
- discharge to evaporation ponds
- injection into depleted oil formations to enhance recovery of oil and for long-term storage of water
- deepwell injection into deep saline aquifers, far below the coal seams.

The method used depends on two things: the salinity of the water and government policy. Alberta Environment decides on a site-specific basis how non-saline water will be handled, depending on the quality of the water and other factors. There is a range of minerals in water and, even if a company has obtained a licence or approval from Alberta Environment (indicating that the water is defined as non-saline), it is still important to find out the level of minerals in the water, to determine how the water should be used or discharged.

If the water meets the *Surface Water Quality Guidelines for Use in Alberta* it may be discharged to a surface water body[142]or stored in a large dugout for future use. If the chemical composition is compatible, theoretically the water may be injected back into the aquifer from which it was diverted, but at a location distant from the CBM production area, or into a different aquifer containing groundwater of lesser quality.[143] The re-injection of non-saline water to recharge an aquifer may be a site-specific requirement imposed by an authorization under the Water Act or by an approval under the Environmental Protection and Enhancement Act. It should be appreciated that re-injection does not return water to aquifers in the same locations or fully compensate for the draw-down in the CBM aquifer. Also surface discharge of water may create problems in a cold climate, such as Alberta's, as the water cannot be discharged when surface water and groundwater are frozen.

[140] Alberta Environment, personal communication, June 2003.
[141] US Bureau of Land Management. 2003. *Final Environmental Impact Statement and Proposed Plan Amendment for the Power River Basin Oil and Gas Project;* http://www.wy.blm.gov/nepa/prb-feis/, and *Final Statewide Oil and Gas Environmental Impact Statement and Proposed Amendment of the Powder River and Billings Resource Management Plan; http://www.mt.blm.gov/mcfo/cbm/eis/index.html* The *Record of Decision and Resource Management Plan Amendments for the Powder River Basin Oil and Gas Project* was issued in April 2003; http://www.prb-eis.org/PRB%20ROD.pdf
[142] The disposal of non-saline water to a surface water body is subject to the *Surface Water Quality Guidelines for Uses in Alberta; http://www3.gov.ab.ca/env/protenf/publications/SurfWtrQual-Nov99.pdf* The guidelines contain tables to provide guidance for protecting the aquatic environment and for the use of water for agricultural purposes (irrigation and watering livestock).
[143] Alberta Environment, personal communication, June 2003.

In some cases the water may be used for crops or livestock, although it may require some treatment, depending on the level of minerals in the water.[144] The water quality would require testing prior to the initial discharge, and also on a regular basis, since the chemical composition of the water from the CBM seams may deteriorate over time.

It is not only the absolute level of various salts that determine whether the water can be used for irrigation but also the relative amounts of various minerals in the water and the soil receiving the water. The *Canadian Environmental Quality Guidelines* set the acceptable limits for the sodium adsorption ratio (SAR) for agricultural land.[145, 146] If the SAR is too high, long-term damage can be done to the structure of soil, as has occurred in some locations in the Powder River Basin.[147]

The dewatering of non-saline water from coal seams may represent a temporary positive benefit for agriculture. However, this is no justification for removing large volumes of groundwater. The dewatering phase will produce the maximum flow in the first few months and will gradually decline, so will not provide a reliable supply of water for any long-term agricultural expansion.

In general, the level of salts in groundwater increases with depth. The actual depth where the water is defined as saline, according to the Alberta Environment definition, varies depending on the strata but is often between 400 and 600 metres.[148]

The dewatering of saline water does not require any licence or approval from Alberta Environment but, as outlined in Section 4, falls under the jurisdiction of the EUB. Saline water is often found in conventional oil and gas wells and the EUB requires a company to report all produced water volumes. The water must be injected into deep saline aquifers, usually below

[144] Alberta has adopted the *Canadian Environmental Quality Guidelines*; http://www.ccme.ca/assets/pdf/e1_062.pdf The guidelines set limits on various substances and determine how water can be used. Water with up to 3,000 milligrams per litre of total dissolved solids (mg/l TDS) may be used for watering livestock, while levels between 500 and 3500 mg/l TDS may be suitable for irrigation (assuming that the sodium adsorption ratio is also satisfactory). In Alberta saline water (that is, water containing more than 4,000 mg/l TDS) must be disposed in deep wells.

[145] The sodium adsorption ratio (SAR) is one indicator that a problem could be caused by the sodium in the water. Excess sodium, in relation to calcium and magnesium concentrations, can destroy the structure of montmorillonite clay particles reducing permeability of the soil to water and air. The effect of SAR on soils, and suitable limits for irrigation water, are explained in the Alberta Municipal Affairs Handbook: *Alberta Private Sewage Systems Standard of Practice 1999.* Appendix B. Table B-3: Recommended Wastewater Quality Standard for Irrigation http://www3.gov.ab.ca/ma/ss/handbook/appendix-b.cfm#SodiumAffectingSoils

[146] The *Canadian Environmental Quality Guidelines* provide levels for the sodium adsorption ratio of five mg/kg for agricultural land; http://www.ccme.ca/assets/pdf/e1_062.pdf

[147] In the Powder River Basin in Wyoming, problems have occurred because water was discharged to ephemeral streams or agricultural land with a SAR ratio of between 12 and 50, far higher values than those permitted in the Canadian Guidelines. J. Morrison, Powder River Basin Resource Council, personal communication, April 2003. See also references to SAR in the *Coalbed Methane Monitor*, at http://www.powderriverbasin.org/prbrc/cbm_monitor_page1.htm

[148] Four hundred metres is a very approximate number. There are some areas in the province where the demarcation between non-saline and saline is deeper than 600 metres, but 600 metres is the maximum depth to which the groundwater is protected. Alberta Environment, personal communication, June 2003.

the zone from which it was extracted. The saline water from CBM wells in Alberta is currently managed in the same way.

Deepwell injection may not be possible for geological or economic reasons and it may not be required by regulators elsewhere in Canada. The way in which saline water is handled in the US depends on the region.[149] For example, in the San Juan basin evaporation ponds as well as deepwell injection may be used for saline water, which has accounted for more than 98% of the water disposal there.[150]

When saline water produced from conventional gas wells is pumped back underground, it is normal to have one central injection well for a number of gas wells. The saline water is thus piped from the gas well to the water injection well. However, leaks may occur from these pipelines. In 2001–2002 there were 174 leaks or ruptures affecting pipelines carrying water in the oilpatch in Alberta, from a total pipeline length of 18,800 km.[151]

Some companies may seek policy changes to facilitate the dewatering of non-saline aquifers and surface discharge in situations where this might not currently be permitted by Alberta Environment,[152] (although the Pembina Institute believes, as indicated in Section 7.4.8, that there should be no relaxation of requirements in place to protect the environment).

Landowners and those living in areas of CBM development should be aware of the potential impacts of dewatering on aquifers and of the need to protect non-saline water aquifers. Extensive parts of Alberta have experienced several consecutive years of drought and various studies indicate that periods of drought could become more intense as global temperatures rise. Thus it is important for landowners and those living in the area to find out what is being done to reduce the risk of non-saline water aquifers being impacted by CBM development.[153] They should then inform Alberta Environment about any concerns relating to an application for a specific project.[154] To provide a baseline should any problems later occur, those living in the

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[149] mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta*. Prepared for Alberta Energy, p. 37; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

[150] D. Cox, Trident Exploration Corp., personal communication, June 2003.

[151] Alberta Energy and Utilities Board. 2002. *Field Surveillance Provincial Summary, April 2001/March 2002,* p. 40 and 45; http://www.eub.gov.ab.ca/bbs/products/STs/st57-2002.pdf

[152] mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta*. Prepared for Alberta Energy, p. 3; "Current regulations governing the disposal and/or diversion of water in Alberta pose significant obstacles and potentially are CBM 'project breakers'. Inherent to CBM production is the need to dewater the coal seams. As noted by the participants in the CBM Workshop, this suggests that policy changes are required to allow for the dewatering of non-saline aquifers as well as consideration of surface discharge."; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

[153] Donahue, W. 2003. "Water supplies will be wasted in coalbed plan," *Edmonton Journal,* January 7, Letters to the Editor, p. A11.

[154] When a company applies for an approval or licence, there will usually be a public notice in the local newspaper, as required by the Water Act, section 108; http://www.qp.gov.ab.ca/documents/Acts/W03.cfm?frm_isbn=0779711424 If the application is advertised, the public can submit a statement of concern (Water Act, section 109) and the director will usually ask the company to contact all those who filed a statement of concern to provide information and to attempt to resolve the issues. Members of the public who have submitted a statement of concern under section 109 and who can show they are "directly affected" by the project, may appeal any decision that Director makes with respect to issuing an approval or licence. The appeal is made to the Environmental Appeal Board, as set out in section 109 of the Water Act.

vicinity of CBM wells should also ask developers to test the volume and quality of water from any water wells in the vicinity of CBM projects. They should ask for and keep a copy of the tests on their own water well. If wells run dry as a result of CBM developments, people living in the area may want assurances that they will be provided with water.

5.4 Venting and flaring of coalbed methane gas

During the early part of the dewatering phase in CBM wells, only a small volume of gas will be produced. Companies may vent or flare it and defer the cost of the equipment required to capture and compress the gas until the volumes reach an economic threshold. Venting and flaring are of concern since the release of gas or its incomplete combustion causes air pollution.[155] Methane, released to the atmosphere during venting and flaring, is also a powerful greenhouse gas contributing to climate change.[156] The light and noise from flares may also be disruptive if they are close to a residence, livestock or wildlife.[157]

The EUB regulates the venting and flaring of gas from all types of oil and gas operations and CBM is currently regulated in the same way as gas from conventional wells. The EUB permits the venting of sweet gas (which includes CBM gas) during well testing and maintenance, but sets criteria for the volume of gas that can be vented and the duration of venting.[158] Venting is permitted only if the volumes of gas are insufficient to burn. Companies are required to report venting operations to the appropriate EUB Field Centre. Well test or maintenance venting is not allowed within 500 metres of a residence unless the resident gives consent and it is approved by the EUB.[159]

The flaring of gas from CBM wells is subject to the same requirements as conventional natural gas well test flaring. The current EUB Guide 60 on flaring does not refer specifically to CBM development.[160] Flaring is permitted, provided the company meets the requirements with respect to the volume of gas flared and the notification of local residents.[161] Flaring or incineration is permitted until gas volumes are sufficient to make piping economic, which in the case of CBM could take several months. The EUB requires a company to consider alternatives to flaring. Instead of flaring, emissions may be reduced by using either an

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[155] Methane is lighter than air, colourless, odourless, and relatively non-reactive compared to other hydrocarbons. In an open space it should not cause the same problems that are found with the incomplete combustion of streams rich in heavier hydrocarbons.

[156] Methane is approximately 23 times more powerful than CO_2 as a greenhouse gas, according to the International Panel on Climate Change, *Climate Change 2001, The Scientific Basis*, section 6.12.2, Direct GWPs, Table 6.7; http://www.grida.no/climate/ipcc_tar/wg1/index.htm This comparison is measured over 100 years.

[157] It may be possible to install a shield on a CBM flare, to reduce the light emitted in one direction.

[158] Alberta Energy and Utilities Board. 2001. *Guide 60: Updates and Clarification,* section 8.2, p. 22–23; http://www.eub.gov.ab.ca/bbs/products/guides/g60/g60-updates.pdf The EUB field offices can make exceptions to these criteria.

[159] Alberta Energy and Utilities Board. 2001. *Guide 60: Updates and Clarification,* section 8.2, p. 23; http://www.eub.gov.ab.ca/bbs/products/guides/g60/g60-updates.pdf

[160] Alberta Energy and Utilities Board, 1999. *Guide 60:Upstream Petroleum Industry Flaring Requirements;* http://www.eub.gov.ab.ca/bbs/products/guides/g60/g60-1999.pdf This guide refers to solution gas flaring and also to venting of gas from pressure vents, storage tanks, etc., but does not mention venting and flaring from CBM wells.

[161] Alberta Energy and Utilities Board, 1999. *Guide 60: Upstream Petroleum Industry Flaring Guide,* Chapter 3; http://www.eub.gov.ab.ca/bbs/products/guides/g60/g60-1999.pdf

incinerator or a catalytic converter, which converts small and variable gas streams to CO_2 (see Section 7.5.4).

The EUB is revising Guide 60 that regulates venting and flaring. The draft refers to CBM in the section on well test flaring[162] and also contains a short section on CBM, which recognizes that the extraction of CBM is different from that of conventional oil and gas.[163] CBM venting is exempt from the duration and volume limits set for venting during well testing or maintenance.[164] It is not known what volumes of CBM will be vented or how the total volumes will compare with the venting from conventional natural gas wells. The Clean Air Strategic Alliance has an Alberta-wide plan to reduce venting and flaring from oil wells (that is, solution gas) but there are currently no targets to reduce venting and flaring from CBM.[165]

5.5 Gas migration into groundwater aquifers

Methane sometimes naturally migrates from gas reservoirs into aquifers, but this process can also occur as a result of incomplete casing on wells. Methane migration into groundwater aquifers has been a side effect of CBM development in some places in the US. Methane in groundwater can then flow to the surface and be released to the air via residential or agricultural groundwater wells or it may travel with the groundwater to the place where the water naturally outcrops at the surface or the bottom of a lake or river. The methane in groundwater can be a nuisance to groundwater users as it can interrupt the flow and pressure of water, and can be an explosion hazard if it is allowed to concentrate inside an enclosed structure or home. As indicated above, it is also a potent greenhouse gas.

During the 1980s, CBM development in the US San Juan Basin occurred in areas where conventional oil and gas wells had been drilled beginning in the 1950s and 1960s.[166] Unlike modern wells, these early oil and gas wells were not cemented to the surface. Thus, when the CBM seams were dewatered, some methane migrated upwards through the annulus[167] of these old wells and into groundwater aquifers. Once this problem was recognized, both Colorado and

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[162] Alberta Energy and Utilities Board. 2003. *Draft Guide 60: Upstream Petroleum Industry Flaring, Incinerating, and Venting*, p. 15, section 3, Temporary and Well Test Flaring and Incinerating; http://www.eub.gov.ab.ca/bbs/products/guides/g60/g60-draft.pdf

[163] Alberta Energy and Utilities Board. 2003. *Draft Guide 60: Upstream Petroleum Industry Flaring, Incinerating, and Venting,* section 8.8; http://www.eub.gov.ab.ca/bbs/products/guides/g60/g60-draft.pdf

[164] Alberta Energy and Utilities Board. 2003. *Draft Guide 60: Upstream Petroleum Industry Flaring, Incinerating, and Venting.* See section 8.8 (3), which exempts CBM wells from compliance with section 8.6, item (4); http://www.eub.gov.ab.ca/bbs/products/guides/g60/g60-draft.pdf

[165] Clean Air Strategic Alliance. 1998. *Management of Routine Solution Gas Flaring in Alberta: Report and Recommendations of the Flaring Project Team;* http://www.casahome.org/uploads/FPT_final_report.pdf and Clean Air Strategic Alliance. 2002. *Gas Flaring and Venting in Alberta: Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project Team;* http://www.casahome.org/uploads/FVPTRptANDRecsFinalVersionJUN-21-2002.pdf and EUB *Guide 60: Upstream Petroleum Industry Flaring Guide;* http://www.eub.gov.ab.ca/bbs/products/guides/g60/g60-1999.pdf This guide provides management plans for flaring from gas plants, and an initial set of management plans for venting. However, there is at present no reduction target for venting or flaring from CBM wells.

[166] The information in this section is based on personal communication from R. Griebling, Director of the Colorado Oil and Gas Conservation Commission, US, month and year?.

[167] The "annulus" is the space between the pipe and the hole where it is located, or between two concentric lengths of pipe.

New Mexico required special testing of the annuli[168] of all conventional wells to reduce the extent of gas migration.[169]

Starting over 50 years ago in some areas Alberta has experienced extensive oil and gas development. In 1998–1999 over 800 cases of gas migration were reported, as well as over 3,800 surface casing vent flows.[170] Since CBM reservoirs in Alberta are "tight," there have been very few cases where natural methane leakage has occurred.[171] Where CBM development reduces the pressures, there is the potential for gas from coal seams to enter groundwater aquifers through the annuli of old wells or wells with leaky casing. This should be detected by casing vent flow tests required in Alberta. Industry has identified the need to encourage baseline analysis of methane gas seepage.[172]

5.6 Hydraulic fracturing

As explained in Section 3, hydraulic fracturing serves to open up the coal seams and help release the CBM. It is common to add substances to the water to assist the fracturing process and in the US there have been concerns that these substances could contaminate shallow aquifers and affect drinking water.[173] In theory this might happen where a CBM well is drilled in the non-saline water zone or where the fracturing of a coal seam below the non-saline groundwater zone extends upwards into the non-saline water zone. In almost all cases with CBM wells, the height of the hydraulic fractures is limited to within 1–10 metres above the coal seams, or 1–3 metres below the seam.[174]

Hydrocarbons, such as diesel fuel that contains various toxic substances, may be used in fracturing fluids but water-based polymer gels are preferable from an environmental

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[168] "Annuli" is the plural form of annulus.

[169] The special testing procedure is called surface casing vent flow testing. The surface casing is the first string of casing put into a well. It is cemented in place and is intended to shut off shallow water formations and provide the basis for well control. The vent flow casing test is to find out whether fluids or gas are entering the surface casing, which could occur for several reasons. The EUB regulation requires surface casing vents to remain open to the atmosphere, which would relieve any pressure build-up, thus minimizing pressuring-up a groundwater aquifer. In Alberta, if the surface casing does not provide protection to the base of the groundwater, then the production casing must be cemented to the surface to ensure groundwater protection is in place. Note: In the US surface casing vent flow testing is called "bradenhead testing."

[170] Alberta Energy and Utilities Board, *Field Surveillance 1998/1999 Provincial Summaries*, Statistical Series 57, p. 42–43; http://www.eub.gov.ab.ca/bbs/products/STs/st57-1999.pdf

[171] Gunter, W. 2003, cited in "Climate change solutions may be found in coalbed methane recovery," *Climate Change Central Newsletter* 5: January, p. 4; *http://www.climatechangecentral.com/info_centre/C3Views/default.asp* Where leaks have occurred as a result of human activity, for example from underground gas storage operations, it has been possible to successfully mitigate the problem. W. Gunter, Alberta Research Council, personal communication, June 2003.

[172] mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta.* Prepared for Alberta Energy, p. 4; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf A study has been conducted on gas migration in conventional wells in one region: Canadian Association of Petroleum Producers and Saskatchewan Research Council. 1996. *Migration of Methane into Groundwater from Leaking Production Wells Near Lloydminster, Report of Phase 2 (1995);* http://www.capp.ca/default.asp?V_DOC_ID=763&PubID=24653

[173] Natural Resources Defense Council. 2002. *Hydraulic Fracturing of Coalbed Methane Wells: A Threat to Drinking Water; http://www.ogap.org/resources/200201_NRDC_HydrFrac_CBM.htm*

[174] D. Cox, Trident Exploration Corp., personal communication, June 2003.

perspective.[175, 176] Oil-based fluids are not commonly used for fracturing CBM, but if they are used a company is required to notify the EUB Operations Division.

As a result of landowner complaints that hydraulic fracturing had contaminated their water wells, the US Environmental Protection Agency investigated this issue. They determined that, since groundwater will flow towards the well where the pressure is lowest, it is unlikely that the fracturing fluids would migrate beyond the well zone. Although the study did not find definitive proof that drinking water wells had been contaminated by CBM hydraulic fracturing, the agency did advise that, "Water-based alternatives exist and, from an environmental perspective, these water-based products are preferable."[177]

The EUB has a protocol for consulting with Alberta Environment when drilling plans could affect non-saline water production. They are reviewing this issue to determine whether more definitive rules are needed with respect to hydraulic fracturing in shallow zones.[178]

Even if the risk is low, it is important for landowners with water wells in the vicinity to have their water tested prior to hydraulic fracturing to collect baseline information about water quality. This will aid in detecting any potential future changes in water quality that may result from hydraulic fracturing of coal seams. Unless there is interconnectivity between the aquifers, this issue may be of less concern where the coal seams contain saline water.[179]

If supplies of fresh water are limited, a secondary issue with hydraulic fracturing relates to the volume of water where non-saline water is used.[180] Water will be required from a surface or underground source to carry out the initial hydraulic fracturing. If the seams are deep, it may be possible to use water from a deep saline well for the fracturing process, although non-saline water provides the most stable and predictable fracturing fluid. If the wells are shallow and likely to contain non-saline water, it is important to use non-saline water for the fracturing process, since saline water could contaminate the non-saline water contained in the coal seam, which would limit its usefulness. The diversion of non-saline water for fracturing in the White Zone of Alberta requires a licence under the Water Act. Where non-saline water is used, it is

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[175] US Environmental Protection Agency. 2002. *Study of Potential Impacts of Hydraulic Fracturing of Coalbed Methane Wells on Underground Sources of Drinking Water,* p. ES-10; http://www.epa.gov/safewater/uic/cbmstudy.html A company may prefer to use a hydrocarbon-based fracturing fluid since it can dissolve more gel than a water-based system, thus reducing the cost of transporting the fracturing fluids.

[176] Gupta, S., BJ Services. 2002. *Water Conservation on a Project Basis Through Recycling.* Presentation to the Fourth Annual Unconventional Gas and Coalbed Methane Conference, October 23–25, 2002. Calgary, Alberta, Petroleum Technology Alliance Canada and Canadian Society for Unconventional Gas.

[177] US Environmental Protection Agency. 2002. *Study of Potential Impacts of Hydraulic Fracturing of Coalbed Methane Wells on Underground Sources of Drinking Water,* p. ES-10; http://www.epa.gov/safewater/uic/cbmstudy.html

[178] D. Liderth, Alberta Energy and Utilities Board, personal communication, June 2003.

[179] The actual depth at which saline water (as defined by Alberta Environment) occurs varies across the province. Four hundred metres is a very rough approximation. However, this depth will normally be greater than the depth of water wells for domestic and agricultural use.

[180] It may require over 100 cubic metres of water to fracture one well. The average residential household in Edmonton uses 20 cubic metres a month. EPCOR, Average Residential Water Use; http://www.epcor.ca/Residential/Efficiency+Tools+and+Tips/Tools+for+Your+Home/Average+Household+Water+Use.htm

important to ensure that as much water as possible is recycled. There is at least one process for recycling water used for fracturing that reduces the volume of water required by more than half.[181]

5.7 Noise

Noise can be an important issue associated with the development of CBM. The initial drilling of a CBM well and the associated vehicle traffic will create some noise. Once drilling is complete, there will probably be continuing noise from the pump, which brings the water to the surface, and the compressor.[182] With the exception of CBM from dry coals, where the gas flows freely, the pressure of the methane gas when it comes out of the ground is fairly low, compared to many conventional gas operations. It thus has to be compressed before it is piped any distance. Further compression is usually necessary to bring the gas up to the pressure of a main pipeline, so that it can be injected into the pipeline, as is the case in most gas production operations. Due to the need to increase the gas pressures, and also the generally higher density of CBM wells, CBM developments will either have more compressor stations than conventional natural gas wells or an additional stage of compression at existing stations.[183] Although the EUB has strict limits on noise from energy installations,[184] the noise from compressors and pumps could be disturbing, especially due to the relatively high density of wells and the need for a considerable number of compressor stations. It is important for landowners to ask to have compressor stations located as far as possible from a residence. It is possible to reduce the noise from a compressor station through the use of sound baffles, and these should be requested where noise is a concern. Compressors have also been developed that are quite quiet (see Section 7.5.6). It may be possible to locate the compressor at a central facility and pull the gas through at a lower pressure, but this requires larger flow lines.

In addition to the noise from the compressor, there will be local air emissions of nitrogen oxides (NO_x) from the gas or diesel that drives the compressor (unless it is powered by electricity from the grid). NO_x is an acidifying emission that contributes to the formation of ground level ozone and to the secondary formation of fine particulate matter. The EUB and Alberta Environment recognize the need to limit NO_x emissions, as seen by an Informational Letter[185] and Code of Practice for compressors and pumping stations.[186]

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181 Gupta, S., BJ Services. 2002. *Water Conservation on a Project Basis Through Recycling.* Presentation to the Fourth Annual Unconventional Gas and Coalbed Methane Conference, October 23–25, 2002. Calgary, Alberta, Petroleum Technology Alliance Canada and Canadian Society for Unconventional Gas, slides 16 and 17.

182 There may not be a compressor at every well, since one compressor may serve several wells.

183 The number of compressors will vary, but there will likely be two stages in compression. In addition to the compressors located at the wellheads, an additional compressor station is needed to increase the pressure further before the gas is piped into the main pipeline. This might involve approximately one central compressor per township.

184 Alberta Energy and Utilities Board. 2000. *Guide 38a: What You Should Know about Energy Industry Noise; http://www.eub.gov.ab.ca/BBS/requirements/Guides/g38a-2000.htm* For more information see *Interim Directive ID 99-06: Noise Control Directive;* http://www.eub.gov.ab.ca/BBS/requirements/ils/ids/id99-08.htm and *Guide 38: Noise Control Directive — User Guide;* http://www.eub.gov.ab.ca/BBS/requirements/Guides/g38.htm

185 Alberta Energy and Utilities Board. 1988. *Informational Letter IL 88-5 Application for Approval of Natural-Gas-Driven Compressors;* http://www.eub.gov.ab.ca/BBS/requirements/ils/ils/il88-05.htm This informational letter is jointly signed by the EUB and Alberta Environment.

186 Alberta Environment. Undated. *Code of Practice for Compressor and Pumping Stations and Sweet Gas Processing Plants*, http://www.qp.gov.ab.ca/documents/Regs/COMPRESS.cfm?frm_isbn=0773268308

5.8 Cumulative impacts

The cumulative impacts of large scale CBM development in an area will likely be considerable, especially for CBM from seams that need dewatering.[187] Dewatering is a major concern for shallow CBM wells, since it may impact non-saline water aquifers on a regional basis. In addition to this and other issues identified above, there may be substantial impacts on the land surface from the construction of new well pads, interconnecting pipelines and the support infrastructure, including roads, power lines and, in some cases, facilities for storing or re-injecting water. An injection facility will usually require land for water tanks used to filter saline water prior to injection. Storage facilities may also be needed for handling water from non-saline water aquifers. New roads will often need to be constructed to reach the wells, and new pipelines may need to be built to take away the gas and water. Even in areas where it is possible to use some of the roads and pipelines that have been constructed for conventional oil or gas, the disturbance will be considerable and disruptive to those who live there.[188] In regions where there have been no previous oil and gas developments the changes to the landscape will be more dramatic. If the developments occur in natural areas, the fragmentation of the land by roads and pipelines will impact wildlife, while the disturbance of the ground surface will destroy native vegetation and may result in the introduction of non-native species. In areas affected by previous conventional oil and gas activity, a new cycle of CBM development will delay restoration and regeneration. In previously undeveloped areas, fragmentation caused by intensive CBM development will probably be even more serious than incursions made by conventional oil and gas development.

At present there is no requirement for EIAs for CBM projects.[189] (This issue is addressed in the Recommendations, Section 7.4.9).

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[187] The impact of CBM from dry coals may be similar to that from conventional shallow wells.

[188] Assuming a density of four wells per section, there are 144 wells per township, the area of land disturbed by wells is estimated to be 1.5% of the total surface area, even without any allowance for additional land for water well injection sites, booster compressor stations, new roads and pipelines. If there are eight wells per section, as may be required in some areas, the area required will be 3%, without additional facilities, roads and pipelines. [Calculation, based on four wells per section: Each well lease is approximately 100 x 100 metres = 10,000 m^2. 144 sites x 10,000 m^2 = 1.44 million m^2 (that is, 1.44 km^2). 1 sq km = 0.386 sq mile. So 1.44 km^2 = 0.56 sq miles. There are 36 sq. miles in a township, so area required for well pads is 1.5% of area of a township.]

[189] *Alberta Environmental Assessment (Mandatory and Exempted Activities) Regulation*, Schedule 1, Mandatory Activities, (d); http://www.qp.gov.ab.ca/documents/Regs/1993_111.cfm?frm_isbn=0773287426 An Environmental Impact Assessment is required for a water diversion structure and canals with a capacity of more than 15 m^3/second. This is nearly 1.3 million m^3/day, so applies to large scale surface water diversions, not groundwater diversions. British Columbia requires an Environmental Impact Assessment if the pumping rate from an aquifer exceeds 75 litres/second (that is, 6,480 m^3/day). British Columbia Regulation 370/2002 *Environmental Assessment Act, Reviewable Projects Regulation*, Part 5, Water Management Projects, Table 9, 4. Groundwater Extraction Projects; http://www.qp.gov.bc.ca/statreg/reg/E/EnvAssess/370_2002.htm#section11 This could potentially apply to CBM developments if there are many wells dewatering one aquifer.

6. Enhanced Coalbed Methane Recovery

CO_2 is the most common greenhouse gas that contributes to global climate change. It is usually released to the atmosphere when fossil fuels are burned. In the future, the recovery of CBM may be increased by using CO_2 to displace the methane gas in coal seams.[190] This not only enhances the recovery of the methane but could offer the opportunity to store the CO_2 underground. Capturing CO_2 from industrial sources and storing it underground will help reduce greenhouse gas emissions that result from burning the methane. CO_2 is already being used on a limited commercial basis to enhance oil recovery,[191] but enhanced CBM recovery techniques are still being developed. The most extensive field tests for enhanced CBM recovery have been conducted in New Mexico by Burlington Resources Inc.[192, 193]

The Alberta Research Council began working on enhanced methane recovery in 1996 and developed a pilot project in deeply buried coal seams in the Fenn–Big Valley area, southeast of Red Deer, Alberta.[194, 195] In addition to using pure CO_2, the project tested the potential for injecting a mixture of CO_2 and nitrogen (to simulate industrial waste gases.[196] Micro-pilot projects will be followed with multi-well tests with industrial partners in other parts of Alberta. The first project using CO_2 is being planned with Suncor Energy Inc.[197]

Enhanced CBM recovery can start as soon as the dewatering phase has been completed. Seismic surveys may be used to identify the extent of the dewatered zones in the coal seams, so that the position of the wells for injecting CO_2 can be located on the surface to correspond with the dewatered area. Research is planned that will use seismic surveys to track the underground movement of injected CO_2 plumes.[198] Some of the injected CO_2 will bond with the coal and should be securely stored unless the coal is mined or disturbed by, for example, an earthquake

[190] Enhanced CBM production has the potential to increase the well production rate and the amount of recoverable reserves.

[191] CO_2 is injected into the ground in special injection wells to increase the recovery of oil from older oil wells at several locations in Alberta and Saskatchewan: Petroleum Communication Foundation. 1999. *Our Petroleum Future: Exploring Canada's Oil and Gas Industry,* Sixth edition, p. 49. The Petroleum Communication Foundation has been replaced by the Canadian Centre for Energy; http://www.centreforenergy.com

[192] Climate Change Central. 2003. "Climate change solutions may be found in coalbed methane recovery."*C3 Views* 5: January, p. 3; *http://www.climatechangecentral.com/info_centre/C3Views/default.asp*

[193] Schoeling, L. and M. McGovern. 2000. Pilot test demonstrates how CO_2 enhances coalbed methane recovery. Petroleum Technology Digest Abstracts of Case Studies, September; http://www.pttc.org/case_studies/PTdigest9-00.htm This website also provides a link to the full article.

[194] Gunter, W.D. 2001. CO_2-*Enhanced Coalbed Methane Recover: Micro-Pilot Testing*, Alberta Research Council; http://www.cspgconvention.org/2001abstracts/4AA-089.pdf

[195] Various articles in Climate Change Central. 2003. *C3 Views* 5: January 2003, p. 2–6; http://www.climatechangecentral.com/info_centre/C3Views/default.asp

[196] Alberta Research Council. 2000. *Alberta Field Pilot to Test* CO_2 *Enhanced Coalbed Methane Recovery;* http://www.arc.ab.ca/energy/Coalbed_pilot.asp

[197] Sustainable Development Technology Canada. 2002. *Sustainable Development Technology Canada Announces Funding of $6.61M for Clean Technology Projects;* http://suncor.com/bins/content_page.asp?cid=4-18-1283

[198] Richardson, S. and D.C. Lawton, University of Calgary. 2002. *Seismic Applications in CBM Exploration and Development.* Fourth Annual Unconventional Gas and Coalbed Methane Conference, October 23–25, 2002. Calgary, Alberta, Petroleum Technology Alliance Canada and Canadian Society for Unconventional Gas.

that could cause its release. However, it is not yet known whether some of the CO_2 might leak back to the surface, in the same way that natural gas occasionally migrates.[199]

The capacity of the coal seams to store CO_2 depends on the rank of the coal. In laboratory experiments, low rank coals such as lignite have been found to have a capacity to adsorb ten times as much CO_2 as methane. This capacity is reduced with increasing rank of the coal, such that sub-bituminous coals (such as those found in central Alberta) hold about four times as much CO_2 as methane, while high rank coal such as anthracite may hold only twice as much.[200]

Although enhanced CBM recovery is still in the research phase, industry and government are hoping that CO_2 capture and storage will help reduce CO_2 emissions. The Alberta government has announced a royalty credit program to stimulate the use of CO_2 for enhanced oil and gas recovery, which can apply to CBM.[201]

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[199] If the CO_2 slowly leaks back to the surface, it might affect soil organisms or kill vegetation. While the risk of a large leak is probably low, it could be fatal if it occurred in a low-lying area where the CO_2, which is slightly heavier than air, could not quickly disperse.
[200] R. Richardson, Alberta Energy and Utilities Board, personal communication, May 2003.
[201] Alberta Energy. 2003. *New Oil and Gas Recovery Program Tackles CO_2 Emissions*. News release, May 16; http://www.gov.ab.ca/acn/200305/14414.html

7. Recommendations

The Pembina Institute's review of CBM developments indicates that Alberta could experience the start of a new wave of drilling and gas production activity across much of the central and southern part of the province within the next several years. While CBM drilling and production is currently regulated in the same way as conventional natural gas, there are several potential environmental, social and cumulative impacts associated with CBM that distinguish it from conventional natural gas. The public wants to ensure that CBM developers adopt the best operational practices, and that impacts on people and the environment are prevented or minimized. Some groups and individuals are concerned that there is inadequate recognition of the potential impacts of CBM projects; they do not want commercial development to proceed until the public has been fully consulted and the EUB and Alberta Environment have new guidelines and regulations in place to specifically deal with CBM. Moreover, the onus of proof should be on industry to determine the impacts of CBM development and to mitigate those impacts where possible. It should not be necessary for a landowner to prove that there will be negative impacts.

The Pembina Institute proposes the following recommendations in the interest of reducing the environmental impacts of CBM development in Alberta. Many of the recommendations will also be relevant in other jurisdictions.[202] However, the nature of the geology and government regulation will affect the way in which development takes place in areas outside of Alberta and partly determine how the industry needs to be managed in those jurisdictions.

Recommendations

1. **Adopt the precautionary principle**

   Even though the geology is different in Alberta, we should learn from experience in the US and avoid problems that have occurred there.

2. **Provide public input on decisions**

   The public should have input into regulatory changes for CBM as well as input into decisions about individual projects.

3. **Improve public information on CBM development**

   Sound information on CBM development and potential impacts is a prerequisite to meaningful public input.

[202] For example, all the recommendations in Section 7.5 on best practices would be relevant in the Peace River area of northeast BC and many would be relevant elsewhere, too.

Recommendations, cont'd.

4. Improve the regulatory process on CBM development

4.1 Require non-toxic substances for hydraulic fracturing in non-saline water zones

This precaution was advised in a US government study, even though the threat to public health appears to be low.

4.2 Minimize the land area impacted by development

The impact of large numbers of wells and associated roads and pipelines can be reduced by locating several wells on one well pad and directionally drilling, where this is technically feasible. Wells can then be concentrated along a development corridor, limiting land fragmentation.

4.3 Review the cumulative impacts of dewatering non-saline aquifers

It is essential to protect non-saline aquifers as these may be required for human use. Basin-wide/watershed studies should be conducted if there is a potential for widespread effects on non-saline aquifers.

4.4 Evaluate the optimum method to use/dispose of different grades of non-saline water

Alberta Environment must maintain its current standards for handling non-saline water and provide for public input on the optimal use or disposal method, which may depend on the chemical composition of the water.

4.5 Avoid or minimize venting and flaring

Every effort must be made to eliminate or minimize venting and flaring, to reduce air pollution and greenhouse gas emissions.

4.6 Prevent and respond to problems associated with gas migration

While some gas migration occurs naturally, the potential for gas migration from CBM projects should be assessed.

4.7 Improve reporting on CBM projects

This includes cooperation between Alberta Environment and the EUB for reporting on the way in which non-saline water is handled.

4.8 Maintain Alberta Environment's role in the management of water and environmental protection

Some companies would like a one-window approach, but Alberta Environment must continue to manage non-saline water and should have a stronger role in safeguarding the environment.

Recommendations, cont'd.

4.9 Require Environmental Impact Assessments of cumulative effects of large-scale CBM developments

Not only should there be an overall development plan for intensive exploration or commercial projects, but large-scale projects should be subjected to an environmental impact assessment (EIA). The area of land affected and impacts may be comparable to some oilsands projects, such as steam-assisted gravity drainage projects, for which an EIA is required.

4.10 Avoid "grandfathering" of existing CBM projects

Any new regulations should apply to existing operators, within a short period of time.

5 Adopt best practices for operations

Best industry practices can help to reduce the surface impacts when exploring and drilling for CBM, as well as during operations. Limiting the noise from compressors is especially important for those living adjacent to CBM operations.

6 Evaluate enhanced recovery of CBM using CO_2

7.1 Adopt the precautionary principle

New wells, roads and pipelines required for extracting CBM will cause significant changes in the landscape and to some extent will impact water and air.[203] As with any new development it is important to monitor progress and, where necessary, modify regulations to ensure safe practices and minimize negative impacts. Government and industry should adopt the precautionary principle where there are unknown factors. We have the opportunity to learn from experience in the US and to avoid some problems that have occurred there. The magnitude of the potential environmental impacts identified in this document will depend on the nature of the coal formations in Alberta, the way in which the industry is regulated, and the pro-activeness of industry in anticipating problems and adopting best management practices.

With several hundred wells already drilled in the province, industry and government are learning the geological characteristics of CBM formations and can better anticipate impacts.[204] However, there is still much to learn about CBM extraction and its effects in this province and there are many questions that still have to be answered.

[203] The environmental effects may be local or regional impacts of water or air quality, but also include the impact of global greenhouse gas emissions.
[204] Alberta Energy is gathering information to determine the regulatory changes that are needed. S. Rauschning, Alberta Energy, personal communication, May 2003.

7.2 Provide for public input on decisions

Given the range of potentially significant impacts from CBM development, it is essential that the government undertake meaningful consultation with the public. There are two aspects to public consultation: public input into the legislation and regulations for managing CBM development and public input into decisions about individual projects.

Alberta Energy has announced that they are planning a public consultation process on the management of CBM.[205] Industry has also identified the need for public consultation, and the value of multi-stakeholder task groups is supported by the US experience.[206] The government should set out a clear schedule for public input into the review of existing requirements and the development of specific rules for CBM development. As a first step, the public should be invited to comment on the proposed process that will be adopted. In developing policies that will guide the environmental regulatory framework for CBM, there is value in a multi-stakeholder approach, such as that demonstrated by the Clean Air Strategic Alliance for managing air quality issues in Alberta, including their work on gas flaring and venting.[207]

At the project application level, there should be an opportunity for public input into regulatory decisions on CBM projects. The scope for public input should be broadened from what is the current practice for conventional gas wells, since any adverse effects resulting from, for example, the high density of well sites, dewatering of non-saline water aquifers or gas migration, could affect not only the adjacent landowners but also those who live and work at some distance from the actual well site. To provide for effective public input, *all* those potentially affected should be permitted to participate in regulatory decision making on an equal legal basis, including having access to intervener funding. A company should be required not only to notify the local landowners, as is required at present, but also to inform a broader public through an advertisement in the media.[208] Where there are extensive CBM projects, public input may encompass issues relating to groundwater and the way in which non-saline water is used or discharged, as well as other issues such as land fragmentation, methane migration, noise, venting, flaring and issues associated with any type of well drilling and gas

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[205] Alberta Energy. 2002. *Alberta Examines the Potential for Coalbed Methane Development*. News release and Backgrounder, October 22; http://www.gov.ab.ca/acn/200210/13392.html A pre-consultation with key stakeholders will commence in fall 2003 to identify and prioritize issues, including environmental concerns associated with CBM development. Alberta Energy. 2003. *Coalbed Methane/Natural Gas from Coal;* http://www.energy.gov.ab.ca/NR/exeres/FCFEC495-ED04-49EF-9B67-CEE2B151D93E.htm See "Public consultations on natural gas from coal development."

[206] mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta*. Prepared for Alberta Energy; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf The industry proposal for a public consultation process identifies such initiatives as workshops, a CBM Web site and a "made in Alberta" CBM pamphlet. The report cites examples of multistakeholder initiatives in the US (see p. 41) and says: "In summary, consistent with what the Alberta industry stakeholders identified through the Alberta Energy CBM Workshop, the U.S. experience concurs with the importance of multi-stakeholder task groups in order to enhance coordination, communication, and cooperation regarding all aspects of CBM development." (p. 44).

[207] Clean Air Strategic Alliance; http://www.casahome.org/

[208] See also the Pembina Institute. 2002. *Oil and Troubled Waters,* p. 31*;* http://www.pembina.org/pdf/publications/OilandTroubledWaters.pdf

production operation (for example, drilling waste management and safety). The cumulative effects of large scale CBM developments could be examined through an EIA, as recommended in Section 7.4.9.

7.3 Improve public information on coalbed methane developments

Albertans need access to clear information on CBM developments and impacts, both at the provincial level and with respect to specific projects. This information is a prerequisite to meaningful public input. Alberta Energy's CBM Web site provides general information on CBM developments in the province,[209] as will an EUB fact sheet.[210] However, more detailed information should also be collected and made available.

Alberta Energy is currently collecting baseline data[211] and together with the EUB and Alberta Environment should compile a database on both developments and impacts associated with CBM. Since the EUB has recently introduced a separate code to classify CBM wells (as distinct from conventional gas wells), province-wide information on the location of CBM wells can now be collected. Industry has indicated the need for baseline analysis on such things as methane gas seepage and basin-wide watershed studies and for research on environmental impacts of CBM development on water, air and wildlife.[212] They should cooperate with government to conduct such research and analysis. This work, including the findings of such studies, must be publicly available.

At the local level, rural Albertans will need access to information relating to any specific projects that may impact them. This information should include

- details of the potential full development scenario, including water disposal facility locations, associated roads, pipelines, compressor stations and gas dehydration facilities;
- the density of wells (number per section);
- the depth at which CBM is being accessed in each area of exploration/development;
- the sources of noise and ways noise levels will be minimized;
- the length of the dewatering phase (estimated and actual);
- the volume of water expected, the volume actually removed and the characteristics of this water (salinity level, etc.);
- disposal methods to be used for the water;
- any potential impacts of dewatering on non-saline water aquifers;
- baseline conditions prior to dewatering;
- ways non-saline water aquifers will be monitored;
- actions being taken to prevent methane seepage (for example, have all old conventional oil and gas wells in an area been tested for gas leaks?);

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[209] Alberta Energy. 2003. *Coalbed Methane/Natural Gas from Coal;* http://www.energy.gov.ab.ca/com/Gas/NGC/default.htm

[210] The EUB is currently preparing an information sheet on CBM in its EnerFAQs series; http://www.eub.gov.ab.ca/BBS/public/EnerFAQs/default.htm

[211] Alberta Energy. 2002. *Alberta Examines the Potential for Coalbed Methane Development*. News release and Backgrounder, October 22; http://www.gov.ab.ca/acn/200210/13392.html

[212] mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta.* Prepared for Alberta Energy, p. 6; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

- ways potential methane seepage will be monitored;
- duration and methods of venting and flaring during the dewatering phase;
- predictions of the volume of gas to be vented and/or flared; and
- once operations have started, any unexpected impacts of development (for example, methane seeps).

Individual companies could provide this information to local residents, but the Alberta government should also use the information for their database and provide annual summaries to the public. It would also be helpful if the EUB, in conjunction with Alberta Environment, had a central database for landowner concerns, with separate sections for water issues, air quality complaints and other issues relating to operations.[213] This will enable the rapid identification of any problems with the management of CBM and a speedier resolution of those problems.

7.4 Improve the regulatory process for coalbed development

The current CBM projects being developed in Alberta are regulated under existing legislation that applies to conventional gas (see Section 4). The government may find that there are calls from industry to alter current standards.[214] The government must resist such pressure where there is any possibility such changes may result in the lowering of environmental and human health protection. If a project is not economic under current conditions, the resource should stay in the ground until extraction does become economic.

Alberta Energy is initiating a review to determine whether the existing rules for CBM development will continue to be appropriate.[215] The objective of this review should be to strengthen measures to protect the environment; there must be no relaxation of any current requirements. As many more CBM projects are being proposed, this review should be conducted as soon as possible. Regulators should identify a schedule for public input into this review, so that Albertans can help identify the specific rules needed for CBM development.

The review should cover the following key issues:
- land disturbance associated with the extensive leases and the density of wells
- the appropriateness of granting any mineral leases in environmentally sensitive areas
- gas migration
- water quality changes
- water quantity changes associated with dewatering
- air quality and noise associated with venting, flaring and emissions from compressors
- cumulative impacts in areas previously or currently affected by conventional oil and gas development and other industrial activity.

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[213] The importance of a centralized system for complaints about water was also referred to in the Pembina Institute's April 2002 publication, *Oil and Troubled Waters,* Section 5.5, p. 32*;* http://www.pembina.org/pdf/publications/OilandTroubledWaters.pdf

[214] mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta*, p. 22, describes priority issues for water disposal and suggests policy changes with respect to the dewatering of coal seams; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

[215] Alberta Energy. 2002. *Alberta Examines the Potential for Coalbed Methane Development*. News release and Backgrounder, Oct. 22; http://www.gov.ab.ca/acn/200210/13392.html Alberta Energy. 2003. *Coalbed Methane/Natural Gas from Coal;* http://www.energy.gov.ab.ca/NR/exeres/FCFEC495-ED04-49EF-9B67-CEE2B151D93E.htm

In addition to adopting the precautionary principle and tailoring public participation requirements to specifically address CBM developments, as indicated in Sections 7.1 to 7.3, new regulations and enforceable policies are needed to deal with a range of issues. They should

- require non-toxic substances (such as water-based fluids) for hydraulic fracturing where non-saline groundwater could be impacted;[216]
- minimize the land impacted by development;
- assess and prevent cumulative impacts of dewatering non-saline water aquifers;
- evaluate the optimum method to use/dispose of different grades of non-saline water;
- avoid or set limits on the duration of venting and flaring;
- review setback requirements with respect to noise, flaring and also the protection of environmentally sensitive areas;
- prevent and respond to problems associated with gas migration;
- improve reporting of CBM projects;
- maintain and enhance Alberta Environment's role in the management of water;
- require EIAs of the cumulative effects of large-scale CBM developments;
- avoid "grandfathering" of existing CBM projects if more stringent environmental requirements are introduced.

When more research has been completed, it will also be necessary to review the potential impacts of enhanced recovery of CBM using CO_2. An EIA may also be necessary for large-scale commercial projects that involve the underground storage of CO_2 (see Section 7.6).

7.4.1 Require non-toxic substances for hydraulic fracturing in non-saline water zones

Hydraulic fracturing of the coal seams to facilitate the release of gas has been a cause of concern in the US where it was thought that fluids used in the fracturing process might have contaminated drinking water sources. The US Environmental Protection Agency study of the potential impacts of hydraulic fracturing determined that, "Although the threat to public health from hydraulic fracturing appears to be low, it may be feasible and prudent for industry to remove any threat whatsoever from injection of fluids."[217] They point out that the use of diesel fuel in fracturing fluids was the main cause of concern and that, "Water-based alternatives exist and, from an environmental perspective, these water-based products are preferable."[218] It thus seems advisable to require industry to use non-toxic alternatives.

It is noteworthy that, although the US rarely uses aquifers with greater than 500 mg/l total dissolved solids (TDS) for drinking water supplies, they consider it important to protect waters with less than 10,000 mg/l TDS, "to ensure an adequate supply (through treatment) for present

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[216] Inert gas foams may be used if they do not require toxic additives.
[217] US Environmental Protection Agency. 2002. *Study of Potential Impacts of Hydraulic Fracturing of Coalbed Methane Wells on Underground Sources of Drinking Water*, August 2002 Draft, p. ES-1; http://www.epa.gov/safewater/uic/cbmstudy.html
[218] US Environmental Protection Agency. 2002. *Study of Potential Impacts of Hydraulic Fracturing of Coalbed Methane Wells on Underground Sources of Drinking Water*, August 2002 Draft, p. ES-1; http://www.epa.gov/safewater/uic/cbmstudy.html

and future generations."[219] Currently the groundwater protection zone in Alberta is for water with less than 4,000 mg/l TDS. The value of extending this protection zone to be equivalent to that of the US should be considered with respect to any practices that could negatively impact on water potentially needed to meet future needs.

7.4.2 Minimize the land area impacted by development

Because of the potential high density of CBM well pads and associated roads and pipelines, every effort should be made to minimize their impact. The regulatory process should be reviewed to determine how this can best be achieved. The EUB has a process that gives landowners an opportunity to comment on requests for well densities that exceed the routine one gas well per section, but this process is not sufficient. Exemptions to the standard density appear likely to be the norm for CBM wells.

It is technically possible to use directional drilling technologies to access a large underground area from a single well pad. Horizontal drilling from the base of the well bore, which is one type of directional drilling, has been used to access CBM in several areas in the US,[220] although it may be difficult where there are many thin coal seams. If four wells are drilled directionally from one central pad, the area of land impacted is about 40% of the area affected by four separate wells.[221] Any request for more than one well per section should be carefully scrutinized and a company should be required to evaluate the technical and economic feasibility for multiple wells from one well pad, to keep the number of well pads per section to a minimum.

If the regulatory process encourages companies to minimize their footprint on the land, for example through multiple well pads, there will also be other benefits. Concentrating operations on fewer sites will avoid the proliferation of compressors and reduce the overall area impacted by noise (see Section 7.5.6). This may also help reduce venting and flaring, as indicated in Section 7.4.5. In addition, use of directional drilling will reduce the area required to provide the right-of-way for pipelines and may make it possible to concentrate wells along development corridors, or adjacent to pipelines and powerlines, thus reducing the amount of land fragmentation caused by CBM development.

Rather than using the conventional ditching technique, companies should also be asked to evaluate the potential to plough-in pipelines that have less than a six-inch diameter, since this can reduce the surface area impacts from the normal 15 metres to as little as three metres.[222] Companies must, however, be required to carry out operations with the right equipment and

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[219] US Environmental Protection Agency. 2002. *Study of Potential Impacts of Hydraulic Fracturing of Coalbed Methane Wells on Underground Sources of Drinking Water*, August 2002 Draft, p. ES-6; http://www.epa.gov/safewater/uic/cbmstudy.html

[220] Molvar, E. 2003. *Drilling Smarter: Using Directional Drilling to Reduce Oil and Gas Impacts in the Intermountain West,* Laramie, WY; Biodiversity Conservation Alliance. http://www.biodiversityassociates.org/blm/pubs/DirectionalDrilling1.pdf See also: Biodiversity Conservation Alliance. 2003. *Groups Consider Directional Drilling as Alternative to Massive Western Drilling Projects*, News release, February 20; http://www.biodiversityassociates.org/blm/news/n20feb03.html

[221] A well pad is usually 100 x 100 metres or 110 x 90 metres, so four wells would require about 40,000 m^3. A well pad for four wells would require a surface lease of approximately 100 x 160 metres (that is, 16,000 m^3).

[222] J. Koch, Trident Exploration Corp., personal communication, May 2003.

under the right environmental conditions to avoid other problems that may arise with ploughed-in pipelines.[223]

7.4.3 Review the cumulative impacts of dewatering non-saline aquifers

Since there will be a relatively high density of wells to access CBM there could be widespread impacts as a result of dewatering coal seams in or adjacent to the groundwater protection zone (that is, where the water is non-saline, or close to the non-saline zone). This will likely occur irrespective of whether single wells are drilled or multiple wells are drilled directionally from a single pad. A review of the regional impacts of this dewatering is essential. A company should be required to provide baseline data on the hydrology of the area, including a risk assessment of potential impacts.[224] If test wells show the potential for widespread effects on non-saline water aquifers as a result of dewatering, basin-wide/watershed studies should be conducted to provide a baseline and evaluate any potential impacts. These studies should then be used to help determine whether the operation should proceed. Alberta Environment already requires information on the impact of individual projects, but they should be able to require a review of the broader impacts of several projects in a region. This would broaden the basis for public input, since at present the input is limited to a specific project.

While every effort must be made to ensure that non-saline water aquifers used for water wells are not impacted, there must be provision to protect landowners and residents if their wells are affected. Companies should be required to pay for water well tests before, during and after all dewatering operations. These tests should apply for at least one kilometre radius from each CBM well (or one kilometre from the furthest extent of underground drilling, where there is directional drilling). If a water well is found to be impacted, the testing zone should be expanded to include at least a further one kilometre radius from that well.[225] Companies should be required to compensate landowners for any losses, and they should be required to maintain the status of the water supply that was established during the large scale baseline surveys.

7.4.4 Evaluate the optimum method to use/dispose of different grades of non-saline water

Water removed during the initial dewatering of the coal seams can be dealt with in different ways. The EUB requires saline water from CBM wells to be handled in the same way as water from conventional oil and gas wells, through deep well disposal. Such regulation is satisfactory and should be retained. When the water produced at the dewatering phase is non-saline, companies must ensure the water meets Alberta Environment's existing requirements for water quality before discharging it to the surface (as indicated in Section 5.3). While companies have indicated that they may look for a relaxation of current requirements for handling water, it is

[223] Alberta Environment. 2001. *Ploughed-In Pipelines,* Conservation and Reclamation Information Letter, C&R/IL/01-4; http://www3.gov.ab.ca/env/protenf/landrec/documents/2001-4.pdf

[224] These baseline studies should be conducted for experimental and pilot schemes, as well as for commercial production, since much dewatering may take place prior to commercial production.

[225] This proposal is similar to provisions for federal lands in the Powder River Basin in Wyoming. See *Record of Decision and Resource Management Plan Amendments for the Powder River Basin Oil and Gas Project,* April 2003, p. 7 and Appendix B; http://www.prb-eis.org/PRB%20ROD.pdf

essential to maintain existing standards for both saline and non-saline water.[226] Alberta Environment should provide an opportunity for public input into the use and disposal of different grades of non-saline water. Alberta Environment should also require the regular testing of water quality since the salinity of the produced water may increase as the dewatering proceeds. An increase in salinity may require changes in the method of disposal.

A company that wishes to dispose of saline or marginal non-saline water from CBM wells should be required to seek synergies with the conventional oil and gas industry, where large quantities of non-saline water are being used for well drilling and especially for enhanced recovery of oil. Where possible the CBM water should be used instead of non-saline water. The government would need to provide some guidelines to industry (for example, the radius within which the potential utilization of CBM-produced water should be investigated) and should verify that a company has fully investigated this potential use of the water.

7.4.5 Avoid or minimize venting and flaring

Every effort should be made to avoid or minimize the venting of methane, both to protect air quality and to minimize greenhouse gas emissions, since methane is far more potent than CO_2 as a greenhouse gas. With a rapidly increasing number of CBM wells, venting even a small volume of methane at each well will increase methane emissions and make it more difficult to reach greenhouse gas reduction targets. The policy framework developed by the Clean Air Strategic Alliance Flaring/Venting Project Team and implemented by the EUB has been effective in facilitating industry's success in major reductions in the venting and flaring of solution gas (a by-product of oil wells). Continuing efforts to substantially reduce the amount of gas vented and flared in Alberta will be undermined if the widespread release of another new source of methane is allowed.

The EUB regulations with respect to venting and flaring were designed for conventional oil and gas wells, but the draft revision of *Guide 60: Upstream Petroleum Industry Flaring, Incinerating, and Venting* proposes changes in the requirements with respect to the duration of CBM venting. While this is in recognition of the fact that some venting may occur during the initial stages of dewatering, before there is sufficient gas to flare, there should be stringent requirements to minimize and, if possible, avoid any venting of CBM. The Clean Air Strategic Alliance Flaring/Venting Project Team should take the lead in any plans to alter requirements for flaring and venting.[227] This multi-stakeholder team has already worked effectively, using a consensus-based approach, to set and achieve targets for the reduction of solution gas flaring. A similar process would be a reasonable way to set targets for minimizing the emissions from venting and flaring of CBM.

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[226] A report for Alberta Energy notes that, "Current regulations governing the disposal and/or diversion of water in Alberta pose significant obstacles and potentially are CBM 'project breakers'." Participants in a CBM workshop suggested that "policy changes are required to allow for the dewatering of non-saline aquifers as well as consideration of surface discharge." mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta*, p. 5; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

[227] Clean Air Strategic Alliance, Flaring/Venting Project Team; http://www.casahome.org/for_stakeholders/issue_teams/FVPT.asp After a time in abeyance, the team is again active and met in February 2003.

To limit the venting of methane gas in the early stages of dewatering, companies could be required to install pilot flames so that intermittent flaring is possible. The EUB should also require companies to employ directional drilling where feasible and to locate several wells on one well pad, since the volume of aggregated gas should make it economic to collect and pipe the gas at an earlier stage than if each well were on a separate pad.

It is essential that the setbacks between residences and CBM wells be reviewed, since production test flaring may continue for several weeks or months.

7.4.6 Prevent and respond to problems associated with gas migration

Dewatering the coal seams may sometimes result in the migration of methane previously trapped under pressure. While in general the methane will migrate to the CBM well bore, where pumping creates the lowest pressure, it may find other routes to the surface. This may occur via natural pathways through fractures in the rock. Methane may also migrate to the surface through conventional wells in the vicinity that have not been properly cased or abandoned. This is a particular problem with old wells.

As part of the recommended precautionary approach, a company should be required to assess the risk of gas migration prior to starting a CBM project. A geological assessment of the strata should indicate if gas migration is likely.[228] In addition, companies should be required to assess the history of the area to determine if any wells were drilled before the 1970s to ensure they have been properly abandoned in accordance with EUB requirements.[229] This may mean testing for surface vent casing leaks, since gas may leak to the surface if the wells have not have been properly abandoned. For wells that have been constructed since the 1970s, it will be necessary to review their history and obtain data on casing vent flows from the current operators.

A company should be required to indicate what measures will be taken to monitor for and mitigate gas migration and the probability that these measures will be successful. This information should be provided as part of the project application and be clear, transparent and publicly available.

7.4.7 Improve reporting on CBM projects

Information on all aspects of CBM should be reported in such a way that the impacts associated with the development of the industry can be monitored. This information should include the number of wells, the volumes of methane vented and flared, evaluations and reports on gas migration, and the volumes and final disposition of both non-saline and saline water removed from CBM seams.[230] Most of this information will be collected by the EUB (since companies

[228] The discontinuous nature of many coal seams may help mitigate migration via coals.

[229] "Abandonment" has a specific meaning in the oil and gas sector. It refers to the process in which a well is "closed down" so that it can be left indefinitely without damaging non-saline water supplies, potential oil and gas reservoirs or the environment. This includes plugging the well to prevent the movement of water and cementing off the well below the ground surface. Requirements for the abandonment of wells are set out in Alberta Energy and Utilities Board, *Guide 20: Well Abandonment Guide,* 1996; http://www.eub.gov.ab.ca/bbs/products/guides/g20.pdf

[230] For a detailed discussion on this issue see Pembina Institute. 2003. *Oil and Troubled Waters.* Section 5.4.3: Report Dewatering of Aquifers p. 32; http://www.pembina.org/pdf/publications/OilandTroubledWaters.pdf

are required to report all produced water volumes to the Board), but Alberta Environment should obtain the reports on the actual volume of non-saline water removed from CBM wells and on the removal of saline water that companies report to the EUB, so they have an integrated view of dewatering activities and can ensure that this does not create any environmental problems.

7.4.8 Maintain Alberta Environment's role in the management of water and environmental protection

Some companies within the industry have expressed their desire for a one-window approach, combining or merging EUB and Alberta Environment processes.[231] However, it is essential to maintain Alberta Environment's role in the management of non-saline water, and to strengthen their role in safeguarding the environment.

Since non-saline water resources are regulated under the Water Act, it is the legal responsibility of Alberta Environment to manage the licensing and use of non-saline waters. While coordination between the EUB and Alberta Environment should be encouraged, the capacity of Alberta Environment to discharge its water resource responsibilities should be strengthened. For example, there should be mandatory referral of all CBM well projects where there is a potential for co-mingling of water from different zones, particularly if this could result in the mixing of saline and non-saline water. As explained in Section 4, at present the EUB examines requests for co-mingling and has an informal process for consulting Alberta Environment if they consider there may be a risk.

Furthermore, Alberta Environment's role in assessing the cumulative impacts of dewatering, prior to deciding whether to issue a licence, should be expanded. Where there are extensive CBM projects the role of Alberta Environment should be to examine the cumulative impacts of development, as indicated in the next section.

7.4.9 Require Environmental Impact Assessments of cumulative effects of large-scale CBM developments

In 1991 the EUB recognized that there could be significant impacts from CBM development and that a company might be required to file an overall development plan for intensive exploration or commercial development.[232] Not only should an overall development plan be required for intensive exploration or commercial CBM projects, as suggested by the EUB, but large-scale projects should be subject to an EIA.[233]

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[231] mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta,* Prepared for Alberta Energy, p. 22; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

[232] Alberta Energy and Utilities Board. 1991. *Coalbed Methane Regulation*, Informational Letter IL 91-11, p. 4; http://www.eub.gov.ab.ca/BBS/requirements/ils/ils/il91-11.htm . The board stated that, "If a project extends to intensive exploration or commercial development and is in an area with potentially conflicting land use, then the filing of an overall development plan may be required, particularly if reduced spacing is being contemplated and/or environmental and social impacts are likely to be significant." The board indicated that this issue would be addressed by a proposed task group.

[233] This means that an Environmental Impact Assessment (EIA) would need to be conducted prior to pilot projects or commercial developments, but that exploratory wells would not require an EIA. An exploratory program might

The cumulative impacts of CBM development are of special concern, due to the higher density of wells and potential for large-scale development of CBM in a given area. For large-scale CBM operations, or regions where several CBM operations are proposed, a full regional EIA should be required, to examine the full range of environmental impacts. EIAs are mandatory for steam-assisted gravity drainage (SAGD) oilsands projects. The land base affected by a large CBM development may be as great as or greater than that impacted by a SAGD project.[234]

While the Environmental Protection and Enhancement Act provides for EIAs for large-scale oilsands projects and oil and gas processing facilities, at the present time EIAs are not required for large-scale CBM projects. As mentioned previously, a CBM well is currently regulated as if it were a conventional gas well and the drilling, construction, operation or reclamation of a gas well is exempt from an EIA.[235] Only the Minister of Environment has power to overrule this exemption for gas wells and call for an EIA.[236] It will be necessary to modify the regulations to enable a mandatory EIA with public input to be held for large-scale CBM projects.[237]

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involve five to ten wells per township, that is, one well approximately every 3.5 to 7 sections. An EIA would probably be required for pilot projects, since even a pilot project can have widespread environmental and social impacts, as is recognized in IL-91, p. 4. A pilot project can leave a large footprint and it is too late to conduct an EIA once the impact has been made.

[234] The PetroCanada Meadow Creek Steam Assisted Gravity Drainage (SAGD) Project, currently under construction in the Ft. McMurray oilsands region, will serve as an example. The company's EIA and Application suggest that the project development will span 58 sections (37,120 acres). The total disturbed area will be 1,389 acres or 3.7% of the land surface. This is made up of the following: road and pipeline access – 512 acres; facilities – 138 acres; 38 well pads – 620 acres; landfill – 119 acres. The well pads alone represent 1.7% of the total SAGD project area. For comparison, the leases for CBM well sites may be take approximately 1.5% of total area, if there are four wells per section, even without any allowance for additional land for water well injection sites, booster compressor stations, new roads and pipelines. If there are eight wells per section, as may be required in some areas, the area required will be 3%, without additional facilities, etc. Refer to footnote 188 for a detailed calculation.

While there may be room for a compressor on a well site, additional land will be needed for facilities such as water well injection sites, booster compressors, roads and pipelines. Thus the land base affected by CBM is probably comparable to that required for a SAGD project.

In the Powder River Basin, it is estimated that the short-term disturbance of CBM wells (including the construction phase) would encompass nearly three percent of the project area (based on eight well pads per section). Long-term disturbance is projected to be about half that amount. Note: These figures are the average for the entire project area, and percentages are higher in some sub-watersheds. US Department of the Interior, Bureau of Land Management, Wyoming State Office. 2003*Final Environmental Impact Statement and Proposed Plan Amendment for the Powder River Basin Oil and Gas Project.* Volume 2, Chapter 4, p. 4–169; http://www.prb-eis.org/Vol_2/Chap_04.pdf See also the EIS Summary, p. xxiii at http://www.prb-eis.org/Vol_1/front3.pdf and the *Record of Decision and Resource Management Plan Amendments for the Powder River Basin Oil and Gas Project,* April 2003, p. 2; http://www.prb-eis.org/PRB%20ROD.pdf

Although it may be possible to reclaim some of the lease area once a well is constructed, any natural vegetation will have been destroyed and the amount of a lease that can be returned to agricultural use will vary, depending on the land required for compressors, water tanks, etc. and the need to access a well on a regular basis (for example, for removing water, checking equipment).

[235] *Environmental Protection and Enhancement Act*, Alberta Regulation 111/93 *Environmental Assessment (Mandatory and Exempted Activities) Regulation,* section 2 and Schedule 2 (e); http://www.qp.gov.ab.ca/documents/Regs/1993_111.cfm?frm_isbn=0773287426

[236] *Environmental Protection and Enhancement Act,* section 47(b), enables the minister to require an EIA report for exempted activities; http://www.qp.gov.ab.ca/documents/Acts/E12.cfm?frm_isbn=0779717392

[237] It would be necessary to amend the *Environmental Protection and Enhancement Act*, Alberta Regulation 111/93, *Environmental Assessment (Mandatory and Exempted Activities) Regulation*. Schedule 2 (e);

It may not be necessary to put all CBM projects on a mandatory list for EIA review, but two potential triggers could be the absolute area affected by a CBM project or the percentage of land directly disturbed by a CBM project. The establishment of a land-based trigger for an EIA would encourage companies to minimize their footprint on the land. Another potential trigger could be the rate of withdrawal of non-saline water during the dewatering process.

Once CBM projects are removed from the EIA-exempted list, it would also be possible for the appropriate director at Alberta Environment to require an EIA where the director considers that one is justified based on the potential environmental impacts, even if the project is smaller than that for which an EIA is mandatory. This would also enable the director responsible for the Water Act to call for an EIA where there was the potential for widespread impacts as a result of dewatering a non-saline aquifer.

Alberta may also look at the example of BC with respect to EIAs. BC legislation provides three mechanisms that could trigger an EIA of CBM. An EIA review may be triggered by the volume of groundwater expected to be removed by a project. [238] It is also possible for the Minister of Sustainable Resource Management to designate a project as "reviewable." Finally, the proponent can ask for a project to be reviewed.[239] Although no CBM projects have received an EIA in BC, this could occur as development expands.

All issues identified in Subsections 7.4.1 to 7.4.8 should be included when an EIA is required. For example, an EIA must contain detailed baseline data on the quality and quantity of groundwater and the depth of the water table. There should be basin-wide/watershed studies to provide a baseline and evaluate any potential long-term impacts from dewatering. Such studies would help determine how the water that is pumped out will be handled. The potential impacts of air emissions from venting and flaring should also be examined. The effect of CBM development on the landscape should be reviewed in areas where a large number of projects in one area can impede agricultural operations or fragment habitat and impact wildlife. In addition, the EIA should include quantitative risk assessment for facilities and operational procedures. Social impact studies should also be conducted.[240]

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http://www.qp.gov.ab.ca/documents/Regs/1993_111.cfm?frm_isbn=0773287426 The actual geographical extent or potential impacts of operations that would trigger an environmental impact assessment would need to be determined.

[238] BC Environmental Assessment Act, B.C. Reg. 370/2002. Reviewable Projects Regulation, Part 5, Table 9, section 4; http://www.qp.gov.bc.ca/statreg/reg/E/EnvAssess/370_2002.htm#part5 This regulation requires an EIA of groundwater extraction projects where a new facility "consists of one or more works for the extraction of groundwater to be used for the same project or where, in the reasonable opinion of the executive director, the works are so closely related that they can be considered to form a single project," if it is operated intermittently or continuously for more than a year and is designed so that groundwater is extracted at 75 litres/second or more. It is possible that a large number of CBM wells in an area could thus trigger an EIA.

[239] BC Environmental Assessment Act, sections 6 and 7. http://www.qp.gov.bc.ca/statreg/stat/E/02043_01.htm The Minister of Sustainable Resource Management is the minister responsible for this act. A proponent may want to request an EIA review if their project faces public controversy or to facilitate coordination when various levels of government have regulatory responsibilities.

[240] Alberta Energy and Utilities Board. 1991. *Coalbed Methane Regulation*, Informational Letter IL 91-11, p. 4, section 6; http://www.eub.gov.ab.ca/BBS/requirements/ils/ils/il91-11.htm

If a project is allowed to proceed, information gathered during an EIA and comments received during an EIA review process will help companies and regulators find ways to better manage the individual and cumulative effects of CBM development.

7.4.10 Avoid "grandfathering" existing CBM projects

Any new regulations introduced for CBM should apply to all existing operations; there should be no "grandfathering" of operations that have already received regulatory approval. Existing operators should be required to meet any new requirements in a reasonably short period of time.

7.5 Adopt best practices for operations

Both the government regulators and companies should be encouraged to adopt the best practices possible for operations, which may go beyond what is required by existing regulations. The use of best practices by companies advances a "triple bottom line" approach, considering the economic, environmental, and social impacts of their operations. Some companies will strive to listen to stakeholder concerns and to implement best practices, since they are conscious that their reputation depends on more than just meeting the minimum requirements.

Based on experience with CBM in the US and with conventional oil and gas wells in Alberta, there are a number of measures that can minimize potential impacts of CBM. Best practices should aim to

- limit surface impacts when exploring for reserves;
- minimize the surface disturbance "footprint" when drilling;
- minimize risks associated with hydraulic fracturing;
- limit emissions from test flaring;
- ensure water conservation and good management;
- limit noise.

The items listed here focus on those issues that relate specifically to the development of CBM. Other best practices, such as those relating to drilling wastes or the reclamation of well sites, are similar for both CBM and conventional oil and gas wells. The fact that they are not detailed here does not mean that they are not important.

7.5.1 Limit surface impacts when exploring for CBM

Although seismic surveys will not be needed to locate Alberta's coal seams, there are many complex geologic variables that control coal permeability and gas content. It is thus possible that a company will conduct seismic surveys before drilling an exploratory well to help locate the most productive areas. The impact of seismic lines is greatest in forested areas or where natural vegetation is disturbed, since they fragment the forest into separate blocks. This degrades wilderness habitat and makes wildlife more vulnerable to attack by both predatory animals and humans.

Instead of conducting a seismic survey in the traditional way along a line-of-sight, a company can reduce the environmental impact by using survey techniques that have less impact, such as those using a Global Positioning System (GPS). A worker holding a portable GPS unit can download specific geographic coordinates from Earth-orbiting satellites with an accuracy within centimetres, depending on the type of equipment and acquisition times. This makes it possible to offset a line around large trees and important natural features, and to reduce lines-of-sight. In sensitive areas, companies can use GPS technology to survey lines and helicopters to transport shot hole drill equipment to the site, thus reducing the number and width of cutlines and minimizing surface disturbance. In settled areas efforts should also be made to minimize the surface impacts of seismic surveys, land compaction and the risk of groundwater contamination (by checking to ensure that all shot holes are properly plugged).

7.5.2 Minimize the surface disturbance "footprint" when drilling for gas

To reduce the environmental impact of CBM extraction, leases should concentrate in areas already developed, thereby limiting the extent of new fragmentation and habitat loss that would occur in wilderness areas. It may then be possible to use some existing pipelines and roads. One effective way to reduce the amount of land used for drilling is to locate several wells on the same well pad. Instead of drilling a series of vertical wells from separate well pads, each with its own road and pipeline, it may be possible to locate several wells on one well pad and drill out in different directions. While directional drilling may be done with slanting wells, it may also be carried out using vertical wells, which then extend horizontally along a coal seam. Such horizontal wells have been used for CBM in several areas of the US.[241] Whether horizontal drilling can be used may depend partly on the stability of the coal seams in a given location.[242] Directional drilling has been used in less than one percent of all CBM wells in the US.[243] Technical and cost constraints generally limit its applicability to seams greater than 300 metres in depth.

By focusing development on multiple well pads and drilling directionally, it is possible to concentrate development along a corridor, centred on the main pipeline. This reduces the land needed for roads and pipelines and can greatly reduce land fragmentation.

Multiple well pads not only reduce the area of land required for well pads, roads and pipelines, they also enable companies to more efficiently recover water and gas during the dewatering period. When the gas from several wells is collected, the combined volume will be sufficient to allow the gas to be flared or piped at an earlier stage in the process, which will reduce the period of venting, and so on (see Section 7.5.4). It is not yet known how many wells per pad will be technically possible for CBM, but using directional drilling to construct multiple wells from a single well pad is a common practice for conventional and heavy oil wells, including

[241] Molvar, E.M. 2003. *Drilling Smarter: Using Directional Drilling to Reduce Oil and Gas Impacts in the Intermountain West.* Laramie, WY; Biodiversity Conservation Alliance, p. 4, 11–12; http://www.biodiversityassociates.org/blm/pubs/DirectionalDrilling1.pdf

[242] McClellan, P., Advanced Geotechnology Inc. 2002. *Assessing Borehole Instability Risks for Horizontal Wells in Coal and Fractured Shales*. Presentation to the Fourth Annual Unconventional Gas and Coalbed Methane Conference, October 23–25, 2002. Calgary, Alberta, Petroleum Technology Alliance Canada and Canadian Society for Unconventional Gas.

[243] D. Cox, Trident Exploration Corp., personal communication, June 2003.

steam-assisted gravity drainage recovery of oilsands. In Alaska one company has drilled over 20 directional oil wells from a single surface location.[244]

In addition to minimizing the size of the footprint, the impact in natural areas can be reduced by timing drilling activity to avoid times when animals are migrating, mating or giving birth.

7.5.3 Minimize risks associated with hydraulic fracturing

Saline water should be used, where possible, for fracturing coal seams containing saline water. Non-saline water should be used to fracture coal seams containing non-saline water. No hydrocarbon-based additives should be used for fracturing in non-saline water zones, but water-based or other non-toxic alternatives should be required. The volume of water used for hydraulic fracturing should be minimized, by recycling as much water as possible.

7.5.4 Limit emissions from venting and flaring

It is essential to minimize venting and flaring to limit both local air pollution and greenhouse gas emissions. Flaring or incinerating gas is preferable to venting as it not only reduces the risk of fire or explosion, but also the emission of gases that contribute to climate change. Flaring converts methane into CO_2, which has a lower global warming potential. However, flaring itself poses concerns due to the toxic air pollutants (referred to as products of incomplete combustion) that can be released.

To avoid venting of methane during the early stage of dewatering, the gas can be collected and burned intermittently by installing a flare stack with a pilot light.[245] Incinerators, which destroy gas more thoroughly than flares, can be used instead.[246] An alternative to venting, flaring or incinerating small, variable streams of methane is to use catalytic converters to convert the gas to CO_2.[247]

Methane that would otherwise be flared could be captured and used to run a generator to operate the pump that brings the water to the surface during the dewatering phase of a CBM well.[248] Propane or diesel can be used for start-up and as back-up if the volume of methane is

[244] BP Exploration (Alaska) Inc. 2001. *BP and the Environment on Alaska's Northern Slope,* Environmental Performance Report 2001, Part 3, Status of Environmental Protection, section 3.1.2 Footprint Reduction; http://alaska.bp.com/alaska/environment/2001/Part3.pdf While this example for conventional oilfields is not directly comparable with CBM development, it shows ways in which the footprint of operation can be reduced, when this is a priority. Measurements from aerial photographs indicate that less than 0.5% of the land surface was disturbed by roads, pads and gravel pits for five projects that started production in 1993 or later. In the Northstar project, where production started in 2001, the surface disturbance was 0.05%. This compares with some earlier projects that impacted between 2% and nearly 3% of the land surface. See Table 3-2.

[245] M. Gatens, MGV Energy Inc., personal communication, April 2003.

[246] See, for example, Questor Technology Inc.; http://www.questortech.com/ One company is currently testing the use of an incinerator with CBM gas during the dewatering phase. D. Motyka, Questor Technology Inc., personal communication, May 2003.

[247] New Paradigm Engineering Ltd. is working with Scott-Can Industries on low-cost modular converters that can covert even small, highly variable or dilute methane streams without the need for a large stack, an open flame, or additional gas for incineration. B. Peachey, New Paradigm Engineering Ltd., personal communication, June 2003.

[248] According to the International Panel on Climate Change methane is approximately 23 times more powerful than CO_2 as a greenhouse gas. While flaring or converting the methane to CO_2 is believed to be preferable to venting and reduces the estimated GHG impact of the methane-containing stream from 23 tonnes CO_2

not sufficient. If there are already pipelines nearby it may be economic to pipe even relatively small quantities of gas, although even small quantities of gas will first have to pass through a dehydrator to remove moisture before it enters a main pipeline.[249] If multiple wellheads are located on one well pad, it will be possible to aggregate the small volume of methane from each well as piping the gas will become economic at an earlier stage in dewatering process.

7.5.5 Ensure water conservation and good management

The best practices for water management and conservation will depend on the local situation. CBM development should be avoided in areas where a preliminary assessment of the hydrogeology indicates that dewatering could result, directly or indirectly, in a draw-down of non-saline, shallow groundwater. While this is especially important in instances where landowners rely on those supplies of water for domestic purposes, the long-term protection of non-saline groundwater should always be the priority.

All CBM projects in the non-saline water zone should have a comprehensive groundwater monitoring program. This should include a baseline study of water quantity and quality, so that any changes as a result of CBM development can be identified. All existing water wells in the project area should be tested for productivity and quality. Tests should be conducted before, during and after the dewatering stage to ensure that any water discharged meets the appropriate Alberta Guideline for Surface Water Quality. This monitoring program should include domestic water wells. The reason for ongoing testing is that the quality of the water may change during the course of the dewatering process and this could alter the way in which the water should be managed. This program should also be designed to detect methane migration.

If industry is permitted to discharge non-saline water and the activity takes place in areas where there is a shortage of non-saline water, efforts should be made to optimize the use of the water, including use for livestock watering and irrigation. However, since the supply of water will be temporary, it will not provide a sustainable source on which to base any increase or change in agricultural activity. Before water is used for irrigation, the soil should be tested; even if the water is within acceptable limits with respect to salinity, the sodium adsorption ratio of the soil may mean that the water could damage the soil structure (see Section 5.3).

In some cases it may be preferable to re-inject the water back into a compatible aquifer, rather than to discharge it at the surface. This may be because it is desirable to help recharge a groundwater aquifer or because there are problems with storing water in winter until it can be used or discharged in spring and summer. Water may also be injected if the level of salts in water that is by definition non-saline is still too high for direct discharge to a surface stream and the demand for water does not justify the cost of treating it.

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equivalent/tonne methane to about 2.75 tonnes of CO_2e, the energy is wasted. It is possible to mitigate and potentially utilize the methane to generate power, using a standard engine generator that uses low-pressure gas. This power can contribute to the power supply used to operate the pumps. B. Peachey, New Paradigm Engineering Ltd., personal communication, June 2003.

[249] Gas must be dewatered to prevent hydrate formation during cold conditions. The gas may be dehydrated using a glycol dehydrator, molecular sieve or other dehydration unit; warmed using line heaters; or injected with methanol to prevent it from freezing.

Another way to conserve water is to use saline produced water from CBM wells to replace the use of non-saline water, where non-saline water is used for enhanced oil recovery. As indicated in Section 7.4.4, the government should require CBM companies to look for synergies with conventional oil operations and to investigate the possibility of using saline or marginal non-saline water from the CBM process to replace non-saline surface water or groundwater.

Where the water is saline, pipelines and wells used to transport and re-inject saline water should be carefully monitored electronically and inspected visually in order to reduce the incidence of leaks that can damage the soil, vegetation and surface water bodies.

7.5.6 Limit noise

Both pumps and compressors can be noisy. Compressors may not be needed at every wellhead and should be located as far as possible from residences and places of work. The noise should be kept to a minimum, especially in areas with low ambient noise levels. Noise levels can be reduced by installing a state-of-the-art compressor with a lower basic noise level.[250] Where the noise level from an existing compressor is disturbing, a baffle around it can reduce the sound. Once again, if there are multiple wells on a single pad, the noise from pumps and compressors will be concentrated into fewer areas and it may be easier to locate them away from residences. It may be possible to use a central compressor to suck gas along the line instead of pushing it with a normal compressor. In this case, larger diameter pipes will be required from the wellhead to the compressor site.

7.6 Evaluate enhanced recovery of coalbed using CO_2

If current research proves successful, it is likely that CO_2 will be injected into coal seams to enhance the recovery of CBM and to reduce emissions of this greenhouse gas. While there is a need to reduce global emissions of CO_2, it will be important to study the benefits and risks of CO_2 storage in coal seams prior to embarking on large-scale storage projects. It is also essential that funding for research on enhanced CBM recovery does not divert public resources away from the development of renewable energy and energy efficiency, which are environmentally sustainable and do not create any emissions.

[250] PC Compression Inc. of Nisku, for example, has recently developed a state-of-the-art, low-noise emission compressor. It is driven either by electricity or natural gas and is suitable for CBM operations; http://www.pccompression.com/gateway.htm

8. Questions Landowners May Want to Ask

This chapter offers questions that landowners and others potentially impacted by CBM development may want to ask a company and, perhaps, the regulator before the start of operations.[251] Not all questions will be relevant in all situations.

8.1 General plans

Question	Explanatory notes
Will the company organize an information session or open house, at an appropriate time, to discuss the project and address the concerns of all residents living within a reasonable radius?	A public information meeting is preferable to an open house, as it gives everyone present an opportunity to listen to the issues raised by their neighbours and ensures that everyone present receives the same information.
How extensive are the company's lease holdings in the area?	Companies usually need to lease mineral rights that extend over several townships to get sufficient gas, since the productivity of an individual well is usually less than for a conventional gas well.
What stage has project reached?	The project may be an exploratory well, pilot project or commercial development. If a well is exploratory, a company may not be able to answer all the questions in this list until after the well is complete.
What are the potential long-term development plans?	Find out how much land will be needed in the area for wells, associated roads, pipelines, compressor stations, and possibly water tanks and injection wells if the well has to be dewatered.
What will be the density of wells, that is, the number of wells per section?	There are likely to be between two and eight CBM wells per section, but there could be more than eight, either due to higher density, or because more than one company is operating in the area.
What will be the density of other facilities, such as compressors, dehydrators, and water well injection sites?	The company should be able to indicate the approximate number per section or township.
For how many years are the wells expected to produce?	This information will not be available for exploratory wells and the duration of pilot projects may also be uncertain.

[251] See also mHeath & Associates. 2001. *The Potential for Coalbed Methane (CBM) Development in Alberta*. Prepared for Alberta Energy, p. 42; http://www.energy.gov.ab.ca/gmd/docs/Coalbed_Methane_Final_Report_Sept_2002.pdf

8.2 The well site

What equipment will be on the well site? Will the company install a compressor?	If the company says they will not need a compressor, ask where the compressor will be located. See more on compressors, below.
From what depth will the CBM be withdrawn?	Well depth is likely to be between 150 and 1,200 metres. The base of groundwater protection (above which the water is non-saline) is likely to be around 400 metres, though this varies widely across Alberta.
If the landowner doesn't like the proposed site of the well: *How extensive is the coal seam? Is it possible to drill the well further away? Can the company use directional drilling from a more distant surface location, to access the methane?*	Directional drilling uses slanting well bores or vertical wells with horizontal drilling through a coal seam at the bottom of the well bore. It costs more than using the usual vertical wells. With directional drilling it is possible to locate several wells on one well pad and also reduce the number of roads and pipelines to individual wells. While little is yet known about how suitable these techniques would be in Alberta, they have been used in the US.
What will the company do to minimize compaction? Will they use lighter drilling equipment?	The type of drilling equipment may depend on the depth of well being drilled.
Is the company using an existing conventional gas well to evaluate for CBM? If so, will the well bore conform to EUB requirements all the way down, and how will the company prove it?	It is important to have the correct casing to prevent co-mingling of non-saline and saline water.
Can the landowner see the bond logs of the well?	Logs record certain characteristics of a well, usually measured by lowering instruments into the well. Cement bond logs indicate the integrity of the bond between cement and casing and between cement and formation. This information indicates whether the CBM well has been properly constructed.
Will the fracturing fluids contain any hydrocarbons or other substances that could damage the groundwater?	Fracturing fluids are used to open up the coal so that the gas can be drawn out. While a US study found little risk of damage to aquifers, it concluded that, from an environmental perspective, water-based fracturing fluids are preferable to those that include hydrocarbons such as diesel fuel.
What is the risk of methane seepage? Has the company assessed the risk? How will potential methane seepage be monitored? Have conventional oil and gas wells in the area been tested for methane leaks?	Gas may occasionally seep naturally through fractures in the rock or through wells that have not been properly constructed or abandoned (that is, closed down).

8.3 Dewatering

Will it be necessary to dewater the coal seams to access the CBM?	CBM wells in the Horseshoe Canyon/Belly River coal formations in the Palliser block, northeast of Calgary, are dry and do not need to be dewatered**.**
If dewatering will be necessary, will the water be saline or non-saline?	Saline water is defined as water having more than 4,000 mg/litre total dissolved solids.
What will the company do to demonstrate isolation of water in shallow water zones — that is, how will they show that there is no interconnectivity between the zone where the coal is being dewatered and non-saline aquifers?	If there is interconnectivity, the draw-down of water in one zone may lead to a decline in the water level in a zone closer to the surface. This should not be an issue when the coal seams are in the deep saline formations.
What volume of water is expected to be produced during the entire dewatering phase?	This depends on the permeability of the coal seam. A wide range is possible.
If the water is non-saline how will the company dispose of the water?	Potable water should have less than 500 mg/l TDS, water for livestock less than 3,000 mg/l TDS, and water for irrigation between 500 and 3,500 mg/l TDS, depending on the crop and also on the sodium adsorption ratio of the soil. Note: By May 2003 only one company had requested an approval from Alberta Environment for dewatering a coal seam with non-saline water; all other companies were operating in either the dry coal seams, or in deep saline formations.
What plans does the company have to monitor groundwater? Will they set up groundwater observation wells?	Monitoring of groundwater is important if the company is dewatering a non-saline aquifer.
What substances will be monitored to ensure that there are no negative impacts on non-saline water aquifers used for water wells (or required for future use)?	In addition to normal water quality parameters, monitoring should include testing for methane.
Will the company monitor the water wells within the area and provide all the landowners with the results, before drilling starts? Will the company continue to monitor the water wells during and after the dewatering phase? What will the company do if it appears that dewatering of the coal seam is affecting other non-saline water aquifers?	This is necessary if the CBM well is in or adjacent to non-saline water aquifers. In addition, dedicated observation wells may be necessary in some instances.
If non-saline water is used or discharged at the surface, will the company continue to monitor the water during the dewatering phase?	The quality of the water can decline as pumping continues.
If the water is saline, where will the injection well be located?	The Alberta Energy and Utilities Board requires saline water to be deep-well injected. One injection well may serve several sections of land.

Is the company planning any dual zone completions or co-mingling that will not meet the standard EUB requirements (that is, will the company apply for an exemption)? If so, what is the reason for doing this and how will the company ensure that there is no co-mingling of water from different zones?	The Water (Ministerial) Regulation does not allow co-mingling of non-saline groundwater of different quality or co-mingling of saline groundwater with non-saline groundwater.
How long is the dewatering phase expected to last?	This will indicate how long facilities will be needed for handling the water.

8.4 Venting, flaring and compressors

How will the small quantities of CBM gas released at the start of the dewatering phase be handled? What volumes of methane does the company expect to vent and/or flare? Is it possible to conserve the gas, rather than vent or flare it?	Venting is not permitted within 500 metres of a residence, without permission of the occupant and approval from the EUB.
Will the company install a pilot flame to allow intermittent flaring?	This will prevent venting of the gas.
Can the company use a shield to prevent disturbance from the light from a flare?	This may be a good idea if the flare is close to a residence.
Can the company use an incinerator, since this will usually produce fewer air emissions than flaring?	A flare stack will still be needed for upset conditions, even if an incinerator is used.
What are the sources of noise and how will noise levels be minimized?	Compressors can be noisy as they are usually powered by natural gas engines. Since CBM is at a low pressure it will be necessary to compress the gas for piping; more compressors will be needed than is usual for conventional natural gas.
What will the company do to minimize the noise from compressors?	Some compressors are less noisy than others. Baffles can be installed to reduce the noise. It is also possible to install the compressor at a central plant to pull the gas through at lower pressure.
Where will the company locate compressors and booster compressors?	It is wise to have compressors located as far as possible from a residence or other areas where noise could be disturbing.

8.5 Pipelines and roads

To what extent can the company use existing roads and pipelines?	Using existing roads and pipelines will reduce the area of land needed for the development and the amount of land fragmentation.
What is being done to minimize the amount of land needed for roads and to locate them so that the land is not fragmented?	Land fragmentation can impede farm operations and increase sources of disturbance for wildlife.
Can pipelines be ploughed in to reduce the area of disturbance?	A conventional pipeline right of way is about 15 metres, but where a pipe can be ploughed in, the area of disturbance may be as little as about three metres, just a little more than the width of the equipment.

8.6 Other points

How long is the pilot (OR experimental OR commercial) phase? Will residents be informed when there are changes in the project status? When? How?	Residents should be kept informed of developments that will affect them.
What is the company approach to hiring local contractors?	Local companies may be able to remove soil, build roads, and so on even if they do not have the expertise for well drilling
Once operations have started, will the company inform landowners of any unexpected impacts of development?	Unexpected impact may include such things as pipeline leaks and methane seeps.
Who is the company contact person, if we have more questions?	It is a good idea to keep the contact number, in case issues arise during future operations.

9. Further Reading

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