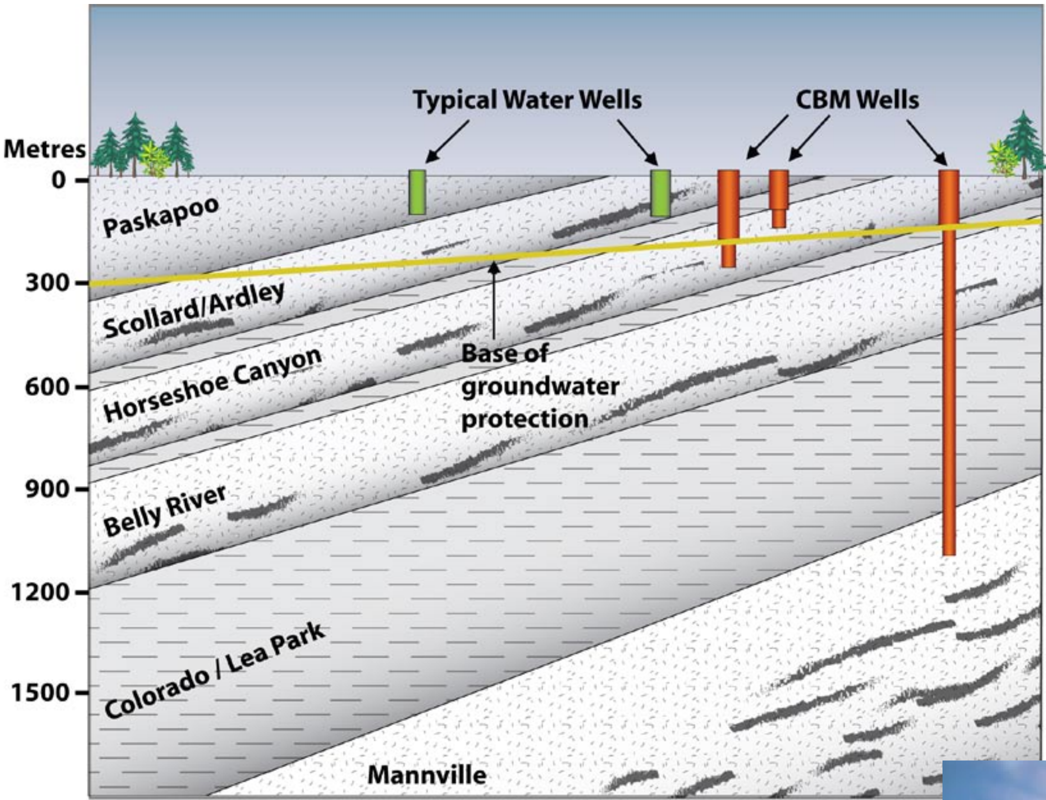
Protecting Water, Producing Gas

Minimizing the Impact of Coalbed Methane and Other Natural Gas Production on Alberta's Groundwater

April 2007



Note: Exaggerated vertical scale; dip on strata 1-2°

Base of groundwater protection

the PEMBINA institute

Sustainable Energy Solutions

Mary Griffiths

Protecting Water, Producing Gas

Minimizing the Impact of Coalbed Methane and Other Natural Gas Production on Alberta's Groundwater

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Sustainable Energy Solutions

Protecting Water, Producing Gas: Minimizing the Impact of Coalbed Methane and Other Natural Gas Production on Alberta's Groundwater

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About the Pembina Institute

The Pembina Institute creates sustainable energy solutions through research, education, consulting and advocacy. It promotes environmental, social and economic sustainability in the public interest by developing practical solutions for communities, individuals, governments and businesses. The Pembina Institute provides policy research leadership and education on climate change, energy issues, green economics, energy efficiency and conservation, renewable energy and environmental governance. More information about the Pembina Institute is available at www.pembina.org or by contacting info@pembina.org.

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About the Author

MARY GRIFFITHS is a Senior Policy Analyst with the Pembina Institute, which she joined in 2000. She has written several books including *When the Oilpatch Comes to Your Backyard: A Citizens' Guide*, which was republished in a completely revised second edition in 2004. She was the lead author of *Oil and Troubled Waters; Unconventional Gas: The Environmental Challenges of Coalbed Methane Development in Alberta; Carbon Capture and Storage: A Canadian Primer;* and *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta.* Mary has served on several government committees, including Alberta Environment's Advisory Committee on Water Use Practice and Policy (which she co-chaired) and the Coalbed Methane/Natural Gas in Coal Multi-Stakeholder Advisory Committee. In 2002, Mary was awarded a Canadian Environment Award and she is the recipient of an Alberta Centennial Medal. She obtained her doctorate at the University of Exeter, U.K. (1969), where she taught geography.

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Executive Summary

As the supply of conventional gas declines, shallow gas and unconventional sources of gas, especially coalbed methane (CBM), are being developed. Landowners are worried that these new wells may impact fresh groundwater, which supplies the water for over 90% of rural Albertans. Water resources are already stressed in parts of central and southern Alberta due to high population density and agricultural use, and climate change is likely to cause major water shortages in the future. The Pembina Institute's mission is sustainable energy solutions, so while we recognize that there are many impacts on water resources, we have focused on the use of water by the oil and gas industry. Having already written *Troubled Waters, Troubling Trends*[1] about the use of water by the oil industry, in this report we focus on gas. It greatly expands some of the issues first discussed in the Pembina Institute's 2003 report on coalbed methane, *Unconventional Gas: The Environmental Challenges of Coalbed Methane Development in Alberta.*[2]

The first chapter gives an overview of natural gas production in Alberta and why the Pembina Institute has written this report. As the price of natural gas increased, it became economic to drill unconventional gas resources. The annual production from individual wells is often smaller today than in the past, but many more wells are being drilled. Over 13,000 conventional gas wells were drilled in 2005, a 65% increase over a five-year period. The number of CBM wells drilled each year grew from a handful in 2001 to over 4,000 in 2005.[3] Other unconventional gas sources, such as tight gas and shale gas, are also being developed. Despite the increase in the number of wells being drilled in recent years, natural gas production in Alberta peaked in 2001.

Chapter 2 examines why Albertans and especially rural landowners are concerned about the protection of water — concerns that were given voice during public input on Alberta's draft *Water for Life* strategy. The government's Coalbed Methane/Natural Gas in Coal Multi-Stakeholder Advisory Committee (the MAC) also heard about those concerns during public meetings and input on its draft recommendations. Fresh groundwater is described as non-saline water by Alberta Environment and the Alberta Energy and Utilities Board (EUB). The depth at which non-saline water becomes saline is referred to as the base of groundwater protection. This depth varies across Alberta, but it is usually between 150 and 600 metres, getting deeper towards the Foothills.

Surface water and groundwater are connected. The depth of shallow groundwater directly affects the flow in rivers and vice versa. It is fairly easy to obtain information on surface water, but more difficult to gather data regarding Alberta's groundwater resources.[4] It is essential for those working on groundwater issues to assess what information is available and what gaps exist. It is also essential that Alberta Environment's groundwater database be expanded to fill those gaps, particularly with information on baseline conditions. Baseline data are essential to minimize the impacts that energy projects and other uses have on groundwater quality and quantity. The

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[1] The Pembina Institute. 2006. *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta,* http://www.pembina.org/energy-watch/doc.php?id=612

[2] The Pembina Institute. 2003. *Unconventional Gas: The Environmental Challenges of Coalbed Methane Development in Alberta,* http://www.pembina.org/energy-watch/doc.php?id=157

[3] This includes new CBM wells and wells that were re-completed to access coal seams.

[4] Surface water is easily measured, but to assess groundwater resources, it is essential to understand the hydrogeology and gather data from wells.

development of CBM has drawn attention to the need to improve knowledge of shallow aquifers. Several new initiatives have been undertaken to increase the knowledge of conditions in the Ardley coal seams (which may contain fresh water) and the overlying Paskapoo aquifers, which are a major source of water for water wells in central Alberta. This attention has cast a spotlight on the reduction in groundwater monitoring that occurred with budget cuts in the 1990s and the need to improve Alberta Environment's long-term monitoring levels to ensure that aquifers do not become depleted.

Chapter 3 describes the main types of gas production in Alberta. Four gas types are discussed: conventional gas, including shallow gas, CBM, tight gas and shale gas. Though methane is the main constituent of each gas type, the proportion each contains varies. For each gas type, a brief description is given of the main characteristics of the gas. This is followed by an examination of how production of that gas might impact fresh water resources, especially groundwater. Finally, the regulatory requirements surrounding the development of the gas are summarized.

The first section of Chapter 1 focuses on conventional natural gas, but the main EUB requirements for gas production set out in *Directive 56* apply not only to conventional gas, but also to other forms of gas. In addition the EUB issued several directives in 2006 that relate specifically to CBM and shallow gas. *Directive 27* sets restrictions on shallow fracturing. *Directive 35* enforces Alberta Environment's requirements for baseline water well testing, which must be conducted before a company drills a CBM well that will be completed above the base of groundwater protection. *Directive 43* requires a company to gather information on shallow strata while it is drilling. This information will help identify shallow aquifers and will aid in the evaluation of locations where oil and gas activity might impact shallow aquifers. *Directive 44* makes it mandatory for a company to notify the EUB if it produces more than 5 m^3/month of water from a well that has any completions above the base of groundwater protection, and to take action to protect shallow aquifers. EUB field surveillance staff conduct inspections for compliance and help enforce all directives.

The second part of Chapter 3 summarizes the characteristics of CBM development and its rapid growth in Alberta. As some coal seams are shallow, there are concerns about potential impacts of CBM production on fresh groundwater. One third of the recommendations of the MAC relate to water. Some of the recommendations have already been implemented and others are in progress. Alberta Environment established baseline water well testing for shallow CBM wells (those that are above the base of groundwater protection) in 2006 and regulates the withdrawal of water from non-saline aquifers. The Ministry is developing a Code of Practice that will apply if a CBM well produces more than a set minimum volume of non-saline water; if the volume of produced water exceeds that specified in the code, a company must submit an application to Alberta Environment to divert water. This application must be accompanied by a detailed technical report which includes a field-verified survey of all area water supplies (springs, wells and dugouts) and groundwater characteristics. Alberta Environment plans to develop a policy for the beneficial use of produced water.

The third section of Chapter 3 describes shale gas. There are extensive shale formations in the Western Canada Sedimentary Basin, but interest in gas from shale has grown only recently, as more accessible resources have diminished and the price of natural gas has increased. Since there is little production yet from shales in Canada (and the EUB does not have a separate code to identify shale gas), the impacts of shale gas production in different regions of the U.S. are examined. Many shale formations in the U.S. are dry but some produce fresh water. Sometimes fresh water is required to fracture the shales. The main lesson is that the geological characteristics of shale are diverse, so it is not at present possible to predict the potential impacts in Alberta.

The fourth section of Chapter 3 addresses tight gas. As for shale gas, interest in tight gas, which comes from reservoirs with low porosity and low permeability, has also grown in recent years. Tight gas is found in the deep basin that lies east of the Foothills in Alberta and extends into northeastern British Columbia. Tight sand reservoirs do not usually contain much water but, as with shale gas, they usually require extensive fracturing to access the gas.

There are many common elements to gas production, irrespective of the source of the gas. Thus the fourth chapter examines the entire development process from seismic exploration, through the drilling and completion of wells, to the handling of produced water and well reclamation. Every stage in gas well development has the potential to impact water resources, as the following examples show:

- Fresh water is required for drilling mud, which is used to cool and lubricate the drill bit and bring cuttings to the surface as a well is drilled. The mud also forms a filter case on the wellbore walls, which is intended to prevent fluid losses and seal off formations from one another. Some landowners are concerned that, if fluid losses occur at the same depth as their water well, contaminants in the water used for drilling (such as *E. coli* found in water taken from dugouts) or compounds used in drilling mud (which can be extremely varied) could get into their water supply. The EUB is reviewing the science on groundwater contamination by introduced bacteria, but some studies suggest that coliform bacteria do not not survive for long periods in an aquifer.
- Various substances are used to fracture rock formations to increase the productive capacity of a gas well so that gas can flow to the well in commercially significant quantities. Nitrogen gas is the dominant fluid used for fracturing coal seams that do not contain any water (which is the majority of wells in the Horseshoe Canyon Formation, the main formation developed in Alberta) and most is returned to the atmosphere (which consists of 80% nitrogen) during flowback operations. In shallow formations, fracturing fluids may get into fresh groundwater. The practice is under review by an EUB committee to determine if it can be done without risking the integrity of groundwater, and whether interim measures introduced in 2006 to protect adjacent oil, gas and water wells need revision. The EUB does not allow potentially toxic substances to be used for fracturing above the base of groundwater protection.
- Water may be used to fracture some formations and the volume of fresh water required may be an issue in some locations. Some companies report they are starting to recycle the fracturing fluids.
- As gas is produced from a formation, pressure will decline and water may flow into the gas-bearing area and be produced with the gas. In coal seams or shales that contain mobile water, the water must be co-produced from the start, with the aim of contributing to further pressure reduction and increasing the amount of gas flow to the wellbore. If the gas wells are shallow, and in communication with fresh water aquifers, the removal of this water might cause significant draw down in these aquifers. Alberta Environment has various requirements that aim to prevent harmful impacts from such activity.
- If a conventional gas well has been producing water at the end of its life, some water will continue to flow into the gas-bearing zone after a well ceases operations and is shut in or

abandoned (that is, closed down in accordance with EUB directives). Water and gas will continue to flow within the reservoir until the pressure gradients created by the production of water and gas stabilize. If the gas-producing zone is shallow, this may gradually draw some water from adjacent fresh aquifers if they are in communication with the gas-producing zone.

- Natural gas migrates naturally underground, but despite regulatory and operational practices to keep it from occurring, occasionally gas may migrate from the formation where it is being produced, e.g., in deep conventional gas seams, through the wellbore into groundwater and sometimes into water wells. The risk of this happening increases as the number of wells and fracture treatments proliferate in shallow zones. The presence of methane in water wells may also be due to bacteria in the groundwater, the buildup of bacteria in water wells that have not undergone routine maintenance, operations (that is, over-pumping), or the fact that the water well is completed in a coal seam, which naturally contains methane. Alberta Environment's investigation of water well complaints in the period since January 2004 suggests that only a very small proportion of the total complaints are due to oil or gas activity. Between January 2004 and November 2006, staff had received 55 complaints about water wells where there was mention that the problem might be due to CBM. In the majority of cases no linkage to CBM could be found, but 10 cases where still under investigation. However, it may be very difficult to definitively prove what causes a change in water quality. Baseline water well testing in areas where CBM development is above the base of groundwater protection, which was introduced in May 2006, should help in the evaluation of problem water wells. The source of gas can sometimes be determined from its composition and the isotopic characteristics of the methane and other gases, as is explained in Appendix A. Some landowners feel that baseline water well testing is not stringent enough.
- Commingling of gas produced from deeper formations with gas produced above the base of groundwater protection could result in cross-contamination of aquifers, if water is produced with the gas. The EUB aims to minimize this risk with various restrictions on commingling of gas produced from formations that are above the base of groundwater protection. Companies must immediately report to the EUB if a well that is perforated above the base of groundwater protection produces more than 5 m^3/month of water.
- If water is produced from deep conventional, CBM or shale-gas formations, it may be saline. This water is trucked or piped to a deep disposal well. EUB data show that in 2005 over 20,000 km of water pipelines were associated with oil and gas production and there was on average one leak every 117 km. These leaks would usually contaminate the surface and soil with salt, which must then be cleaned up by the company responsible. Deep disposal injection should not affect shallow zones.

Chapter 5, on best management practices, identifies some measures that landowners would like energy companies to adopt to reduce the risk to water of contamination. These practices, which go beyond the EUB and Alberta Environment requirements, include requiring baseline testing for water wells, irrespective of the type or depth of the gas well, and adopting the precautionary principle to ensure that shallow fracturing will not impact fresh aquifers. They also favour finding productive, environmentally sound uses for produced water. Project-based planning and environmental assessment would assist in identifying and minimizing potential impacts and encourage companies to share pipelines and other infrastructure.

In Chapter 6, landowners are encouraged to become well informed and to negotiate with a company planning a gas well on their land. Issues covered include seismic exploration, setbacks, baseline water well testing, protection of fresh water aquifers and the management of drilling wastes and produced water. If negotiations are unsuccessful, the EUB's Appropriate Dispute Resolution process may help a landowner and company resolve issues. Landowners sometimes have problems with their water wells and a government publication, *Water Wells that Last for Generations*,[5] can help them identify the cause. It also provides advice on water well maintenance and the control of bacteria that grow in water wells.

The recommendations in the last chapter are addressed to government. Additional measures are proposed to fully protect fresh water aquifers and ensure there is no dewatering or contamination. The government should extend protection of shallow aquifers to greater depths to provide more usable water in the future, in anticipation of climate change. Knowledge of fresh water aquifers must be improved, which means gathering sufficient information on flows and recharge rates to establish water budgets, and increasing the number of monitoring wells to assess changes in groundwater levels and quality. The government should require energy companies to submit project plans and undertake an environmental impact review of an entire project before applying for individual well licences. Requirements for baseline water well testing should apply to all types of gas well, and companies should be required to submit an analysis of gas composition and isotopic characteristics for a representative sample of sites taken from each formation producing gas. This would help to identify the source of gas found in water. Several recommendations relate to increasing surveillance of industry operations, while others show how the system for handling landowner complaints and objections could be improved. The government should also do more to ensure that water wells are routinely tested. Revision to the Crown Mineral Disposition Review Committee is proposed, to ensure that mineral leases are not granted in areas where gas development is inappropriate.

An appendix on gas composition and isotopic analysis, a glossary and a list of abbreviations complete the report.

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[5] Alberta Agriculture, Food and Rural Development. 2001. *Water Wells that Last for Generations*, http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/wwg404 Call 1-800-292-5697 (toll free) for a printed version. The department has been renamed "Alberta Agriculture and Food".

1. Introduction

1.1 Why a report on gas and water?

Unlike energy there is no alternative source of water.[6]

More than 350,000 oil and gas wells have been drilled in Alberta since production started, which is about one well for every ten people living in the province. At the end of 2005, energy companies were operating almost 206,000 wells.[7] In addition, there were many gathering and processing facilities and over 370,000 km of pipeline associated with hydrocarbon production.[8] All this activity can impact water in a variety ways. Approximately 300,000 water wells[9] have been drilled for agricultural and domestic use across the province and 90% of rural Albertans rely on groundwater.[10] Many are very concerned about the protection of water resources, especially as climate change is expected to reduce natural flows in rivers and groundwater recharge.

In an earlier Pembina Institute report, *Troubled Waters, Troubling Trends*, we wrote about oil production and its impact on water resources.[11] In 2003 the Pembina Institute first examined the environmental implications of coalbed methane (CBM) development in Alberta.[12] Now we put the spotlight on all types of gas production, as those living in rural Alberta are worried that new developments, such as drilling for CBM, could impact their groundwater resources. The Pembina Institute's mission is sustainable energy solutions, so we focus on energy issues, but recognize that there are many other activities that impact water resources in the province.

This report aims to provide an overview of the ways in which gas production may affect water, the relevant government regulations, and additional measures that can further reduce the risks. It covers every aspect of gas production, from seismic exploration, through the drilling and completion of wells, to the handling of produced water and the final closing down (abandonment) of a well. The report is written not only to inform landowners, but also to show

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[6] This sentence is taken from World Business Council for Sustainable Development. 2006. *Business in the World of Water: The WBCSD Unveils its Water Scenarios Project*, media release, 15th August. *http://www.wbcsd.org/Plugins/DocSearch/details.asp?DocTypeId=33&ObjectId=MTk5OTI* Although alternative sources of fresh water can be obtained by the desalinization of ocean water or deep brines that are outside the atmospheric water cycle, the desalinization process usually requires a lot of energy and the environmentally safe disposal of the extracted salt may be a problem.

[7] Alberta Energy. 2006. *Ministry of Energy 2005-2006 Annual Report*, p. 14, *http://www.energy.gov.ab.ca/docs/aboutus/pdfs/AR2006.pdf* The report refers to "almost 206,000 non-abandoned wells". This includes wells that are in active use or that have been temporarily shut-in. Abandoned wells are those that have been closed down in accordance with EUB requirements, so that the site can be reclaimed.

[8] Alberta Energy and Utilities Board. 2006. *ST 99-2006: Provincial Surveillance and Compliance Summary 2005*, p. 76, *http://www.eub.ca/docs/products/STs/st99_current.pdf* There is approximately 1 km of pipeline for every 10 people living in Alberta.

[9] There are records for over 500,000 water wells in the Alberta Environment database but some well locations have multiple record entries (e.g., one for drilling, one for water chemistry and one for abandonment). Steve Grasby, Natural Resources Canada, personal communication with Mary Griffiths, January 10, 2007.

[10] Alberta Agriculture, Food and Rural Development. 2001. *Water Wells that Last for Generations*, Module 1. *http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/wwg404* See also, *Understanding Groundwater*, *http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/wwg406?opendocument*

[11] Griffiths, Mary and Dan Woynillowicz. 2006. *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta*, The Pembina Institute, *http://www.pembina.org/energy-watch/doc.php?id=612*

[12] The Pembina Institute. 2003. *Unconventional Gas: the Environmental Challenges of Coalbed Methane Development in Alberta*, *http://www.pembina.org/energy-watch/doc.php?id=157*

industry and government why landowners are concerned and how their concerns can be addressed, through more research into water resources, use of best management practices and further improvements in regulations. Information on groundwater and the importance of water well maintenance is also covered.

The sources of gas in Alberta are changing and so are the potential impacts. As conventional natural gas reserves become depleted, new sources of "unconventional" gas are being developed. Unconventional gas includes not only CBM, but also tight gas (from sandstones and limestones) and shale gas, which is a very new source of gas in Canada. Gas hydrates are another form of unconventional gas that may be produced in Canada in the future.[13] These unconventional sources differ from conventional gas in that they need special drilling, completion, and/or stimulation (such as fracturing of the formation) technologies to develop and maintain the flow of gas in commercial quantities. They tend to produce at lower pressure and have lower production rates than conventional gas wells, but wells may continue producing for many years.[14] Due to the low production rates, many more wells are required to produce a given volume of gas.[15] In some cases production may come from shallower formations than previously developed, where the groundwater is fresh (or non-saline).[16]

The rapid rate of change, as seen with CBM development, means that many new wells are being drilled while the government is still learning about groundwater resources and before there is comprehensive baseline data on shallow groundwater. Only with this baseline information is it possible to determine where the water in the aquifers is being recharged, whether current water withdrawals are sustainable and whether the rate of recharge is changing.[17] Two eminent scientists recently said: "We predict that in the near future climatic warming, via its effects on glaciers, snow-packs, and evaporation, will combine with cyclic drought and rapidly increasing human activity in the WPP [Western Prairie Provinces] to cause a crisis in water quantity and quality with far-reaching implications."[18]

Many activities can impact groundwater, including agricultural production and a variety of industrial projects. Approximately 3,500 new water wells are drilled in Alberta each year, which

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[13] Gas hydrates, which are another form of unconventional gas, are found in areas with low temperatures and high pressures, e.g., on the seabed off the coast of British Columbia and in the Mackenzie Delta (the Mallik gas hydrate field). Their commercial development is unlikely to start within the next 20 years. Petroleum Technology Alliance Canada. 2006. *Filling the Gap: Unconventional Gas Technology Roadmap,* p. 8, http://www.ptac.org/cbm/dl/PTAC.UGTR.pdf

[14] Dawson, Mike. 2005. *Unconventional Gas in Canada: An Important New Resource.* Presentation given on behalf of the Canadian Society for Unconventional Gas (CSUG) at BC Oil and Gas Conference. Ft. St. John, October 5, slide 4, http://www.csug.ca/pres/CSUG%20051005%20BC%20O&G%20Conference.pdf

[15] With respect to Canadian gas production: "Back in 1996, the average gas well - when it came on production - it came on production at about 600 Mcf per day. The average gas well, today, is around 200 Mcf/day - a little bit better than that… In 1996, we drilled 4,000 successful gas wells. The price of gas spiked in 2001 - we drilled 11,000 gas wells. We've had about a 10% increase in productivity by drilling three times as many wells. 2003: even though we drilled 14,000 wells, gas production fell by about 3%. So, it basically hit a peak in 2001, maintained that plateau till mid-2002, declined 3% in 2003. We're now drilling nearly 16,000 gas wells per year, as of 2005, and production is about what it was back in 2002." Transcript of interview with David Hughes, Geological Survey of Canada, on Canada's Oil and Natural Gas, November, 30, 2006. Global Public Media, http://www.globalpublicmedia.com/transcripts/827 This interview provides an update on information found in *Energy Supply/Demand Trends and Forecasts: Implications for Sustainable Energy Future in Canada and the World;* Hughes, J. David. Geological Survey of Canada, Open File 1798, 2004; 47 pages. This is available at http://geopub.nrcan.gc.ca/publist_e.php by searching on "Hughes" and "2004".

[16] See section 2.2 for more information on non-saline (fresh) water and Appendix B: Glossary, for a definition.

[17] Over the very long term, changes in aquifer recharge rates might affect the replacement flows into shallow gas-bearing formations from which gas and water have been withdrawn.

[18] Schindler, David. W., and William F. Donahue. 2006. "An impending water crisis in Canada's western prairie provinces." *Proceedings of the National Academy of Sciences,* April 10, http://www.pnas.org/cgi/reprint/0601568103v1

probably means a proportionate increase in the withdrawals from shallow aquifers.[19] An increase in water withdrawals may impact water levels and water quality. If water is withdrawn faster than the natural rate of recharge (which will be low during periods of drought), then groundwater levels will fall. The water resources in parts of central and southern Alberta are already stressed due to the effects of high population density and agricultural use.[20] The conservation of water will be crucial — and this includes protecting groundwater, which may be an increasingly important resource as surface flows decline.[21] It is essential to learn more about Alberta's shallow aquifers and to be prepared to take action to ensure they are not depleted by unsustainable withdrawals associated with any type of use.[22]

The cumulative impact of gas production is seen in the growing footprint of wells on the land surface and in the fragmentation caused by an expanding network of seismic lines, roads, pipelines and compressor sites. Landowners may be affected by noise from compressors and traffic, emissions from flaring, damage to sensitive vegetation and a variety of other impacts. We deal with some of these issues in *When the Oilpatch Comes to Your Backyard: A Citizens' Guide.*[23]

We do not believe that anyone intentionally damages groundwater, but we want to minimize the risk. We want government not only to provide good regulations to protect groundwater, but also to ensure there are enough staff to implement and enforce them. We encourage industry to adopt best practices to protect fresh aquifers. If there is any reasonable doubt that a practice might damage non-saline groundwater, industry should adopt the precautionary principle and not proceed. We hope that government, industry and landowners will work together to protect the most precious resource in this province — our fresh, usable groundwater.

1.2 The changing face of gas production

The sources of gas are changing and new developments are so rapid that in ten years' time 80% of gas production in North America may come from wells that are yet to be drilled.[24] Unconventional gas already accounts for 32% of gas production in the U.S.,[25] and it has been suggested that U.S. gas production from unconventional sources will account for close to half of the total production by 2012.[26] It seems that Canada is not far behind and an increasing volume

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[19] Alberta Environment, personal communication with Mary Griffiths, November 2, 2006.

[20] Grosshans, Richard E., Henry D. Venema and Stephan Barg. 2005. *Geographical Analysis of Cumulative Threats to Prairie Water Resources*, International Institute for Sustainable Development, http://www.iisd.org/pdf/2006/natres_geo_analysis_water.pdf Figure 24 shows water use and quality stresses across the south east quadrant of Alberta. This report examines precipitation deficits, as well as demands for human and agricultural use. The shortages in some areas give rise to landowner concerns about the use of water for the oil and gas industry.

[21] It is sometimes forgotten that surface water and groundwater are basically the same resource and surface water and groundwater levels are related. Winter, Thomas C., Judson W. Harvey, O. Lehn Franke and William M. Alley. 1998. *Ground Water and Surface Water: A Single Resource.* U.S. Geological Survey Circular 1139, http://pubs.usgs.gov/products/books/circular.html

[22] It is not the task of this report to examine other uses, but given the increase in the number of people living in rural areas, it would be wise for government to review all groundwater allocations and the estimated use by those who do not require licences, to determine how much water is being withdrawn from fresh water aquifers.

[23] Griffiths, Mary, Chris Severson-Baker and Tom Marr-Laing. 2004. *When the Oilpatch Comes to Your Backyard: A Citizens' Guide.* Second edition. The Pembina Institute.

[24] National Petroleum Council. 2003. *Balancing Natural Gas Policy, Volume 1: Summary of Findings and Recommendations,* p.30, http://www.npc.org/.

[25] Dawson, Mike. 2005. *Unconventional Gas in Canada: An Important New Resource,* B.C. Oil and Gas Conference. Ft. St. John, October 5, slide 6, http://www.csug.ca/pres/CSUG%20051005%20BC%20O&G%20Conference.pdf

[26] Halliburton. 2005."Unconventional Oil and Gas Resources are Huge Solvable Problems", *Unconventional Reserves*, p. 2, A Supplement to E & P, November, http://www.halliburton.com/public/pe/contents/Brochures/Web/H04564.pdf The article cites Cambridge Energy Research

of gas in the not-too-distant future is expected to come from unconventional sources, such as coal seams, shale and tight sandstone. One vision suggests that by 2025 40% of natural gas production in Canada will come from unconventional sources.[27] Another source predicts that by 2025 unconventional gas could account for about 80% of new drilling and 50% of gas production in Canada.[28]

Although unconventional gas resources[29] in Canada are enormous, there are no definitive figures for the recoverable gas reserves (that is, the volume of gas that can actually be produced with current technology at current prices).[30] However, estimates indicate that Canadian reserves of CBM exceed the remaining reserves of conventional gas.[31]

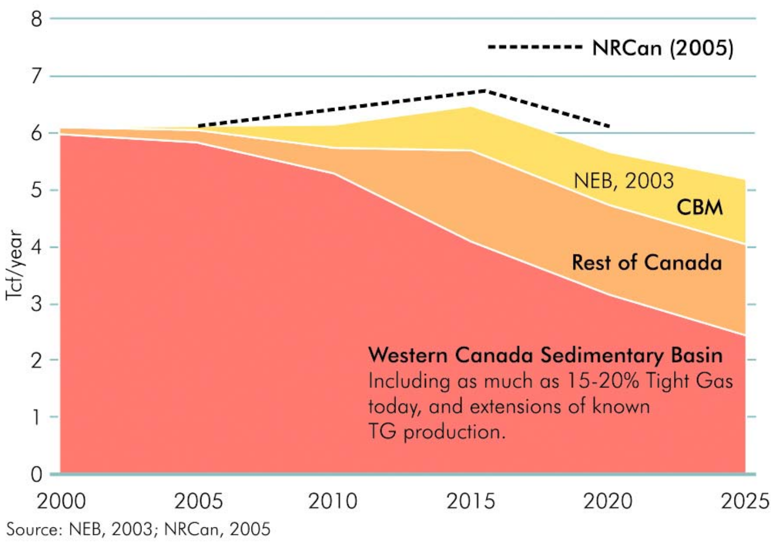

Figure 1-1 Current Canadian natural gas supply projections

Source: Petroleum Technology Alliance Canada, *Unconventional Gas Technology Roadmap,* with permission.[32]

Alberta is a major source of gas in Canada, accounting for almost 80% of total production in 2005, [33] when the province produced 4.9 trillion cubic feet (tcf) of marketable natural gas.[34]

Associates which "estimates unconventional gas plays – tight sands, shale gas and coalbed methane – will constitute close to half of total U.S. gas production by 2012." The article also refers to an Energy Information Association (EIA) estimate that indicates a slower rate of growth, with production of unconventional gas from the lower 48 states growing "from 35% of total Lower 48 production in 2003 to 44% in 2025." Figures from EIA Energy Outlook 2005.

[27] Petroleum Technology Alliance Canada, 2006. *Filling the Gap: Unconventional Gas Technology Roadmap*, p. 4, http://www.ptac.org/cbm/dl/PTAC.UGTR.pdf

[28] Dawson, Mike. 2005. *Unconventional Gas in Canada: An Important New Resource*, B.C. Oil and Gas Conference. Ft. St. John, October 5, slide 6, http://www.csug.ca/pres/CSUG%20051005%20BC%20O&G%20Conference.pdf

[29] The "resource" is the total volume of gas stored in the formation.

[30] Dawson, Mike. 2005. *Unconventional Gas in Canada: An Important New Resource.* B.C. Oil and Gas Conference. Ft. St. John, October 5, slide 7, http://www.csug.ca/pres/CSUG%20051005%20BC%20O&G%20Conference.pdf

[31] Dawson, Mike. 2005. *Unconventional Gas in Canada: An Important New Resource*, B.C. Oil and Gas Conference. Ft. St. John, October 5, slide 7, http://www.csug.ca/pres/CSUG%20051005%20BC%20O&G%20Conference.pdf See also Petroleum Technology Alliance Canada. 2006. *Filling the Gap: Unconventional Gas Technology Roadmap*, p. 7–9, for figures on the ultimate conventional natural gas resource and the estimated CBM, tight gas, shale gas and gas hydrates in place in Canada, http://www.ptac.org/cbm/dl/PTAC.UGTR.pdf

[32] Petroleum Technology Alliance Canada, 2006. *Filling the Gap: Unconventional Gas Technology Roadmap*, Figure 2.4, http://www.ptac.org/cbm/dl/PTAC.UGTR.pdf In that figure, NRCan refers to Natural Resources Canada and NEB refers to National Energy Board.

Encouraged by high prices, over 13,000 new wells were drilled in Alberta for conventional gas in 2005, which was 65% more than the average yearly total for the period 1999–2002.[35] Despite the fact that this was an all-time record for new conventional wells, the production of conventional natural gas in Alberta peaked in 2001 and started declining by approximately 2% per year.[36] The decline in production would be much greater if it weren't for the large increase in wells. As can be seen from Figure 1-2, the number of producing gas wells (for all types of natural gas) has increased two and a half times over a decade.

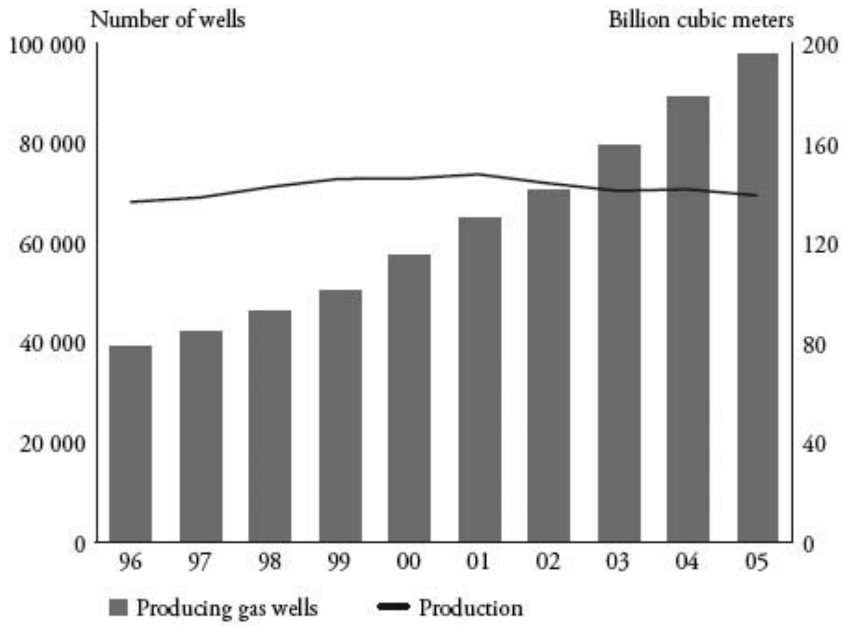

Figure 1-2 Marketable gas production in Alberta and producing wells, 1996-2005

Source: Alberta Energy and Utilities Board[37]

An increasing number of conventional gas wells are in shallow formations and the Alberta Energy and Utilities Board (EUB) "anticipates that shallow drilling will continue to account for a large share of the activity in the province over the next few years."[38] Of successful new conventional gas wells (3,741 wells), 43% were in southeastern Alberta; the Western Plains region of Alberta is seeing an increasing level of activity (3,337 successful conventional gas wells drilled in 2005). In the Western Plains region some of the increased activity may be due to wells drilled for shale gas and tight gas.

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[33] Alberta Energy and Utilities Board/National Energy Board Report 2005-A. *Alberta's Ultimate Potential for Conventional Natural Gas*, p.13, http://www.neb-one.gc.ca/energy/EnergyReports/AlbertaConvNGUltimatePotential2005_e.pdf

[34] Alberta Energy and Utilities Board. 2006. *ST98-2006: Alberta's Energy Reserves 2005 and Supply/Demand Outlook*, p. 5, http://www.eub.ca/docs/products/STs/st98_current.pdf In 2005 0.05 tcf of the total natural gas production in Alberta came from CBM.

[35] Alberta Energy and Utilities Board. 2006. *ST98-2006: Alberta's Energy Reserves 2005 and Supply/Demand Outlook*, p. 5-16, http://www.eub.ca/docs/products/STs/st98_current.pdf In 2005 13,248 conventional gas wells were drilled, an increase of 27% from 2004 and an all-time high.

[36] Alberta Energy and Utilities Board. 2006. *ST98-2006: Alberta's Energy Reserves 2005 and Supply/Demand Outlook*, p. 2, 5-16 and 5-17, http://www.eub.ca/docs/products/STs/st98_current.pdf Natural gas production declined by 2% in 2005 and is expected to have a similar decline in 2006. During the period 1999-2002 an average of 8000 conventional gas wells were drilled each year.

[37] Alberta Energy and Utilities Board. 2006. *EUB 2005 Year in Review*, p. 43, http://www.eub.ca/docs/products/STs/st41-2006.pdf

[38] Alberta Energy and Utilities Board. 2006. *ST98-2006: Alberta's Energy Reserves 2005 and Supply/Demand Outlook*, p. 5, http://www.eub.ca/docs/products/STs/st98_current.pdf

As production from conventional gas wells declines, an increasing proportion of future supply is expected to come from unconventional sources. At the present time, the EUB makes the distinction only between conventional gas and CBM, so production from shale and tight sands is included with conventional gas, even though tight gas and shale gas are usually defined as unconventional gases.[39] They are considered unconventional due to the tight nature of the formations, which means that the gas often does not flow freely and requires special drilling and completion methods to achieve commercial production. For example, production of CBM and other types of unconventional gas frequently requires a higher well density and more extensive fracturing.

The most recent rapid development has occurred with CBM, where the total number of wells in the province more than doubled in a single year; over 4,000 wells were added for CBM during 2005 (which includes both new wells and wells previously drilled for conventional gas that were recompleted for CBM).[40] A further 3,000 wells were completed in coals in 2006, bringing the total to 10,723 CBM wells in Alberta by the end of the year.[41] The number of CBM wells has been increasing far more rapidly than some anticipated.[42] CBM provided 2% of the provincial gas production in 2005, but is expected to supply about 16% of the total marketable gas production in Alberta by 2015 (see Figure 1-2).[43]

[39] "Unconventional gas is most broadly defined by the Society of Petroleum Engineers (SPE) as gas contained in formations from which it is difficult to produce without some extraordinary completion and stimulation practices. The most common unconventional gas formations are low permeability sands ("tight gas"), coals containing coalbed methane (CBM), organic-rich shales, and gas hydrates. One train common to each is a large gas resource in place that is difficult to transform into gas reserves." Petroleum Technology Alliance Canada, 2006. *Filling the Gap: Unconventional Gas Technology Roadmap*, p.1, http://www.ptac.org/cbm/dl/PTAC.UGTR.pdf

[40] Alberta Energy and Utilities Board. 2006. *Bulletin 2006-33: 2005 Coalbed Methane Activity Summary and Well Locations*, http://www.eub.ca/docs/documents/bulletins/Bulletin-2006-33.pdf

[41] Alberta Energy and Utilities Board. 2007. *Bulletin 2007-05: 2006 Alberta Coalbed Methane Activity Summary and Well Locations*, http://www.eub.ca/docs/documents/bulletins/bulletin-2007-05.pdf

[42] In a 2003 publication *Canada's Energy Future* (p. 65), the National Energy Board said in their Supply-Push scenario for Canada that "…CBM development is expected to gradually increase from 300 wells in 2003 to nearly 3,000 wells per year by 2010". In the NEB's Techno-Vert scenario the number of wells would increase to 3,500 by 2010, http://www.neb-one.gc.ca/energy/SupplyDemand/2003/SupplyDemand2003_e.pdf

[43] Alberta Energy and Utilities Board. 2006. *ST98-2006: Alberta's Energy Reserves 2005 and Supply/Demand Outlook*, p. 4-9, http://www.eub.ca/docs/products/STs/st98_current.pdf

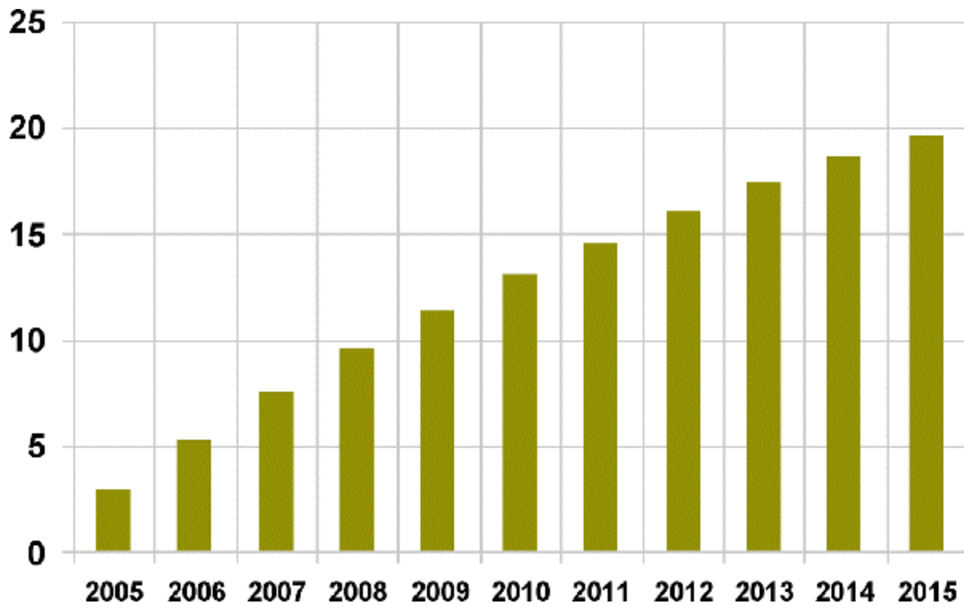

Figure 1-3 Coalbed methane production forecast
Source: Alberta Energy and Utilities Board[44]

At the end of 2005 Alberta's remaining established reserves of conventional natural gas had declined to approximately 40 tcf.[45] The EUB has not yet estimated the total CBM reserves in Alberta that are recoverable,[46] but the Canadian Energy Research Institute has estimated the recoverable national reserves of CBM: "With a recoverable resources estimate of 167 tcf for CBM in Canada, the size of this resource appears to be remarkably similar to estimates for this resource in the United States."[47] Alberta has the most extensive coal resources in Canada, so it seems likely that CBM development will produce more gas than the remaining conventional resources.[48]

Although the EUB does not separate the volume of gas produced from other unconventional sources such as tight sands or shale, it notes that, "Natural gas production from other sources, such as shale gas, may prove to be an additional source in the near future."[49] The National Energy Board estimates that the tight gas resource (i.e., gas from low permeability reservoirs) in

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[44] Alberta Energy and Utilities Board. 2006. *ST98-2006: Alberta's Energy Reserves 2005 and Supply/Demand Outlook*, Figure 4.3, http://www.eub.ca/docs/products/STs/st98_current.pdf

[45] Alberta Energy and Utilities Board. 2006. *ST98-2006: Alberta's Energy Reserves 2005 and Supply/Demand Outlook*, p. 5, http://www.eub.ca/docs/products/STs/st98_current.pdf In 2005 the remaining ultimate potential for conventional natural gas production in Alberta was estimated at 101 tcf. Alberta Energy and Utilities Board/National Energy Board Report 2005-A. *Alberta's Ultimate Potential for Conventional Natural Gas*, p.18, http://www.neb-one.gc.ca/energy/EnergyReports/AlbertaConvNGUltimatePotential2005_e.pdf

[46] The total resource in place is estimated to exceed 500 tcf, but only the reserves in areas of current operation have been estimated. Alberta Energy and Utilities Board. 2006. *ST 98-2006: Alberta's Energy Reserves 2005 and Supply/Demand Outlook*, p. 5, http://www.eub.ca/docs/products/STs/st98_current.pdf

[47] Canadian Association of Petroleum Producers. 2005. *Comments of the Canadian Association of Petroleum Producers before the Senate Committee on Energy and Natural Resources' Natural Gas Supply and Demand Conference, January*, p. 3, *Th*http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=82834

[48] Alberta Energy and Utilities Board/National Energy Board Report 2005-A. *Alberta's Ultimate Potential for Conventional Natural Gas*, p. 13, http://www.neb-one.gc.ca/energy/EnergyReports/AlbertaConvNGUltimatePotential2005_e.pdf. The total CBM resource in place is estimated as 500 tcf.

[49] Alberta Energy and Utilities Board. 2006. *ST98-2006: Alberta's Energy Reserves 2005 and Supply/Demand Outlook*, p. 5, http://www.eub.ca/docs/products/STs/st98_current.pdf

the Western Canada Sedimentary Basin is 300 tcf and the shale gas resource is 250 tcf,[50] but the board does not estimate how much of this gas-in-place will be recoverable. Much of the basin lies within Alberta. Deep basin gas is also likely to be more important in the future.[51]

There is little publicly available information on the development of shale gas in Alberta, but "Shale gas certainly has the potential to be the 'next big thing.'"[52] Interest has grown in this commodity with rising gas prices. In the U.S., shale gas development was encouraged by a federal government tax credit program, and the wide range of experience there will be helpful in understanding the potential impacts of shale gas development in Alberta. Here, shale gas development "will probably be almost identical to what we experienced in the coals. It's the same story, second verse. There are lots of common technologies . . . but different basins require a different approach."[53]

All these developments may have an impact on water, but before we examine the individual types of gas production in Chapter 3, we will provide some background information on why it is important to protect Alberta's water resources and what is being done to achieve this.

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[50] National Energy Board. 2006. *British Columbia's Ultimate Potential for Conventional Natural Gas*, p.23, http://www.neb.gc.ca/energy/energyreports/emanebcgasultimatepotential2006/emanbcgasultimatepotential2006_e.pdf

[51] Canadian Association of Petroleum Producers. 2005. *Comments of the Canadian Association of Petroleum Producers before the Senate Committee on Energy and Natural Resources' Natural Gas Supply and Demand Conference, January*, p. 2, http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=82834

[52] Ball, Candice. 2005. "Shale Silence is Deafening", *Unconventional Gas Supplement – Oilweek*, p. 23, August.

[53] Mike Gatens, Quicksilver Resources Inc. and Past Chairman of the Canadian Society for Unconventional Gas, cited in Jaremko, Deborah. 2005. "Sleeping Giant: Canadian Shale Gas Potential Huge But Waits For Assessment of Technology," p. 42, *Oilweek*, May.

2. Water

2.1 Landowner concerns about the protection of water

People living in rural Alberta told the government about the importance of protecting their water supplies during the public consultations on the draft *Water for Life* strategy. They know that water is the lifeblood of rural Alberta, where the majority of people rely on groundwater. When the government introduced *Water for Life* in 2003, the strategy identified the need to "understand the state of the quality and quantity of Alberta's groundwater supply."[54] This was scheduled as a long-term project for the 2010/11 to 2013/14 timeframe. In the meantime, many new wells are being drilled across Alberta and landowner concerns about the protection of groundwater are increasing.

Issues relating to water were frequently raised at public meetings organized by the MAC in 2004. In 2005, as a result of public response to its draft report, the committee included another recommendation on water well testing.[55] Alberta Environment also heard about the need to protect aquifers when it met the public to explain the new requirement for companies to conduct baseline water well testing before they drill for CBM in shallow coal seams (that is, seams that are above the base of groundwater protection, where the water is non-saline).[56]

Landowners fear that water levels in their wells may fall as a result of oil or gas production. In oil production, the use of fresh water for enhanced oil recovery has been a concern; in gas wells, the production of fresh water from shallow gas-bearing formations, especially from shallow coal seams, is a potential issue. Another concern is that fresh water aquifers may become contaminated by bacteria in the water used for drilling mud (e.g., when the water is taken from a dugout) and by chemicals used in fracturing fluids. A major concern is the risk of gas migrating into the shallow groundwater that supplies landowners' wells. Problems with gas in water wells in areas of CBM production led to questions in the Alberta Legislature[57] and to various features in the media.[58] The explosion of gas in a water well pump house in Spirit River in 2006, in an area of conventional gas production, may have increased concerns about gas migration.[59] It is important for landowners anywhere in the province to realize that it is essential to properly vent a pump house to the outside, to prevent the buildup of naturally occurring gas. The need for this is explained in *Water Wells that Last for Generations*.[60]

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[54] Government of Alberta. 2003. *Water for Life: Alberta's Strategy for Sustainability*, p.12, http://www.waterforlife.gov.ab.ca/

[55] Government of Alberta. 2006. *Coalbed Methane/Natural Gas in Coal Multi-Stakeholder Advisory Committee Final Report*, recommendation 3.3.6, http://www.energy.gov.ab.ca/docs/naturalgas/pdfs/cbm/THE_FINAL_REPORT.pdf

[56] Alberta Environment. 2006. *Coalbed Methane in Coal: Groundwater and Coalbed Methane Information Sessions*, http://www.waterforlife.gov.ab.ca/coal/index.html

[57] See, for example, *Hansard*, Coal-bed Methane Drilling, February 28, 2006, p. 78-79 and March 8, 2006, p. 286-287, http://www.assembly.ab.ca/net/index.aspx?p=han&section=doc&fid=0

[58] See, for example, Jeremy Klaszus. "Trouble in the Fields: Is Our Water Safe?" *Alberta Views*, October 2006, p. 28-33, about the problems encountered in the Hamlet of Rosebud, and Chris Severson-Baker and Mary Griffiths, "To Calm the Troubled Waters", *Alberta Views*, November 2006, p. 7. Gas in water wells may come from various sources, as described in Chapter 4.

[59] Gelinas, Grant. 2006. Feature story in the series *Blueprint Alberta: H2O*, News at Six, October 24 and 25th, http://www.cbc.ca/blueprintalberta/archives.html

[60] Alberta Agriculture, Food and Rural Development. 2001. *Water Wells that Last for Generations*, p.18,. http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/wwg404 Call 1-800-292-5697 (toll free) for a printed version.

Landowners in the Torrington area took their worries about the potential impact of CBM on groundwater to an EUB hearing.[61] They were concerned about the use of surface water for drilling, whether the proposed well casing would adequately protect deeper fresh water aquifers, the potential impact of fracturing and the way in which any water well complaints would be investigated. All these will be discussed in later chapters of this report. In this chapter we examine what is known about fresh groundwater in this province and gaps in that knowledge.

2.2 Fresh and saline groundwater

Water in rivers and lakes is usually fresh. Groundwater may be fresh or salty (saline). Shallow groundwater and surface water are closely related; in fact, they are a single resource. [62] Changes in shallow groundwater levels can impact surface waters, such as rivers and wetlands (and vice versa).

Fresh groundwater is the water that is usually within a few hundred metres of the surface and water becomes increasingly saline deeper in the earth.[63] The degree of salinity is expressed in terms of the total dissolved solids (TDS) in the water. Saline water is defined in Alberta as water with more than 4,000 milligrams per litre (mg/l) TDS.[64] Non-saline water is thus water with less than 4,000 mg/l TDS. Under the *Water Act,* Alberta Environment is responsible for managing all water in the province. A licence is required for the diversion of non-saline water but the diversion of saline water is exempt.[65,66] The EUB requires companies to report on the volume of produced water, whether it is fresh or saline.

In this report we use the term "non-saline" water when referring to specific government requirements.[67] Elsewhere we often use the term "fresh" water, as this is more familiar to many people, but we define it in the same way as non-saline water.

The actual uses of fresh water vary according to the level of dissolved solids in the water. Drinking water (sometimes called "potable" water) should have less than 500 mg/l TDS,[68] while water with higher levels may be used for watering stock or for irrigating crops (see section 4.7).

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[61] Alberta Energy and Utilities Board. 2006. *Decision 2006-102: EnCana Corporation Applications for Licences for 15 Wells, a Pipeline, and a Compressor Addition Wimborne and Twining Fields,* October 31, http://www.eub.ca/docs/documents/decisions/2006/2006-102.pdf

[62] Winter, Thomas C., Judson W. Harvey, O. Lehn Franke and William M. Alley. 1998. *Ground Water and Surface Water: A Single Resource.* U.S. Geological Survey Circular 1139, http://pubs.usgs.gov/products/books/circular.html See also William M. Alley, Thomas E. Reilly and O. Lehn Franke. 1999. *Sustainability of Ground-Water Resources.* U.S. Geological Survey Circular 1186, http://pubs.usgs.gov/products/books/circular.html

[63] For an overview on Groundwater, see Alberta Environment. Undated. *Groundwater Introduction,* http://www3.gov.ab.ca/env/water/GWSW/quantity/learn/what/GW_GroundWater/GW1_introduction.html

[64] *Water (Ministerial) Regulation, section 1(1(z),* http://www.qp. gov.ab.ca/index.cfm

[65] Government of Alberta. 1998 and updates. *Water Act,* sections 3(2) and 26, http://www.qp.gov.ab.ca/documents/Acts/W03.cfm?frm_isbn=0779727428

[66] Government of Alberta. 1998 and updates. *Water (Ministerial) Regulation.* Section 5(1) and Schedule 3, section 1(e) exempt saline groundwater from the requirement for a licence, http://www.qp.gov.ab.ca/documents/Regs/1998_205.cfm?frm_isbn=9780779720699 Since the saline water exemption is in a regulation, not in the *Water Act,* it was determined by a ministerial decision, not by the legislation. Before the *Water Act* became law in 1999, Alberta Environment required diversion permits for saline water. It was found that this type of diversion had little potential to impact fresher waters, so effort was focused on fresh water diversions. Recently, some companies producing small volumes of water with slightly greater than the 4,000 mg/l TDS have submitted applications for permits because of public concern. See also: Alberta Environment. 2003. *Groundwater Evaluation Guideline (Information Required When Submitting an Application Under the Water Act),* http://environment.gov.ab.ca/info/library/7508.pdf Special requirements for diversion of water from coalbed methane wells are described below in Chapter 3.

[67] We attempt to use the same words that the reader might want to search for in government publications; note, however, that the EUB omits the hyphen and writes "nonsaline" in some documents. In the past, both Alberta Environment and the EUB sometimes referred to "usable" water, instead of non-saline, so this word may be found in some documents that have not been updated.

The dividing line between fresh water and saline water is called the base of groundwater protection. This refers to a depth of 15 metres below the deepest non-saline aquifer.[69] The EUB prohibits the use of oil-based drilling fluids (or any other potentially toxic drilling additive) when a company is drilling above the base of groundwater protection.[70] The base of groundwater protection varies in depth. In much of Alberta it is between 150 and 600 metres and it is generally deeper towards the Foothills.[71] The exact depth where fresh water becomes saline varies as it depends on the local geological history, and how the ancient ocean, where the saline water originated, was trapped. Until recently, the base of groundwater protection had not been recorded in detail across the entire province, but the Alberta Geological Survey is scheduled to complete mapping it in 2007.[72]

Some water may flow to the surface with the production of gas. This is referred to as "produced water." It may either be fresh or saline, depending on the formation from which it comes.

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[68] Non-saline water with a very low concentration of salts 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 4 at *http://www.hc-sc.gc.ca/ewh-semt/pubs/water-eau/doc_sup-appui/sum_guide-res_recom/index_e.html* Hydrologists sometimes use the term "fresh water" to describe water with less than 1,000 mg/l TDS and the term "brackish" for water with 1000 – 4000 mg/l TDS; in other cases "brackish" is used to refer to water with more than 4,000 mg/l TDS.

[69] Alberta Energy and Utilities Board. 2006. *Directive 036: Drilling Blowout Prevention Requirements and Procedures***,** p.86, *http://www.eub.ca/docs/documents/directives/Directive036.pdf*

[70] Alberta Energy and Utilities Board. 2006. *Directive 036: Drilling Blowout Prevention Requirements and Other Procedures,* p.89, *http://www.eub.ca/docs/documents/directives/Directive036.pdf* See also, Alberta Energy and Utilities Board. 2005. *Bulletin 2005-04: Shallow Well Operations, http://www.eub.ca/docs/documents/bulletins/Bulletin-2005-04.pdf*

[71] Brenda Austin, Alberta Energy and Utilities Board, personal communication with Mary Griffiths, October 5, 2006. The base of groundwater protection may be between 400 and 1500 metres in the Foothills. Austin, Brenda; Sheila Baron and Stephen Skarstol, 1995. *Groundwater Protection in Wellbores.* CADE/CAODC Spring Drilling Conference, April 19-21, Calgary.

[72] Yee, Beverley. 2006. *Alberta's Strategy for Sustainability.* Presentation at the Petroleum Technology Alliance Canada Conference Water Innovations in the Oilpatch, June 21-22, 2006, *http://www.ptac.org/env/dl/envf0602p04.pdf*

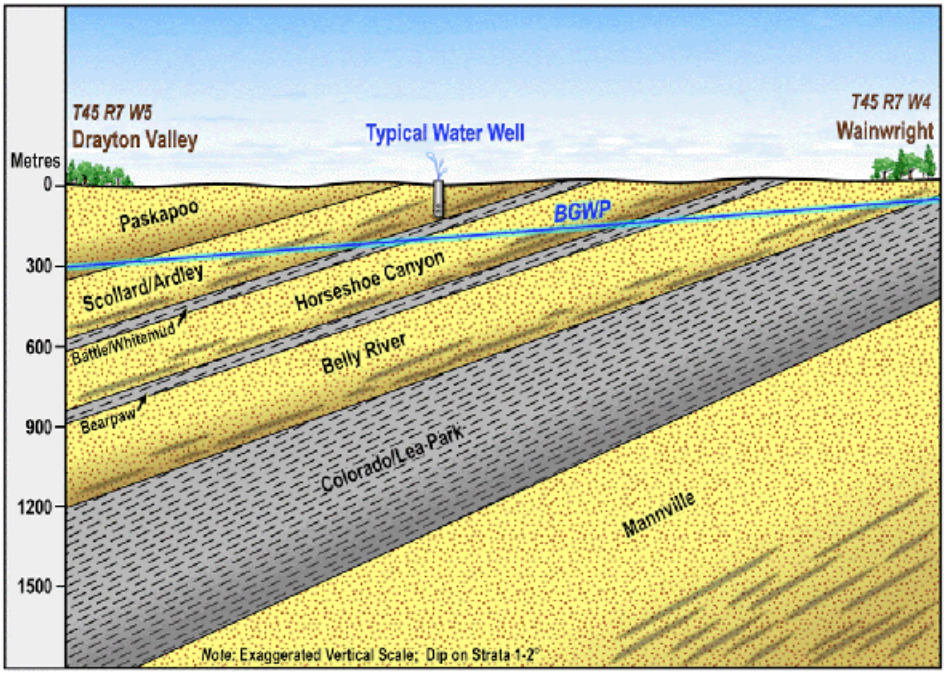

Figure 2-1 Base of groundwater protection in central Alberta

Source: Alberta Energy and Utilities Board[73]

2.3 Alberta's groundwater resources

2.3.1 Existing information on aquifers

Surface water is clearly visible in rivers, lakes or wetlands. It is fairly easy to measure river flows and to see seasonal and annual changes. Much less is known about the state of groundwater. Water is not uniformly available under the Earth's surface. Rock formations that easily allow the transmission (or release) of significant quantities of water from pores between the rock particles or in fractures in the rock are called aquifers.[74] In Alberta, sandstone can make a good aquifer.[75] Many wells are also completed in glacial deposits that overly the bedrock.[76] However, in some areas water wells are completed in coal seams containing water or in fractured shales.

In the 1970s, the Alberta Geological Survey and Alberta Research Council created maps that showed hydrogeological information, including the total yield of aquifers and the general

[73] Alberta Energy and Utilities Board. 2006. *Protecting Water During CBM Development*, slide 14, Community information sessions presentation, *http://www.waterforlife.gov.ab.ca/coal/docs/AENV-EUB_June_26.pps* See other presentations at *http://www.waterforlife.gov.ab.ca/coal/index.html*

[74] Alberta Environment. Undated. *Groundwater. Learn about Water: Aquifers*, *http://www3.gov.ab.ca/env/water/GWSW/quantity/learn/what/GW_GroundWater/GW4_aquifer.html*

For more information on groundwater, see Alberta Environment. Undated. *Groundwater, Introduction*, *http://www3.gov.ab.ca/env/water/GWSW/quantity/learn/what/GW_GroundWater/GW1_introduction.html* and Alberta Environment. 2005. *Focus on Groundwater*, *http://environment.gov.ab.ca/info/library/Focus_On_Groundwater.pdf*

[75] Limestone is also a good aquifer, but very few Albertans use water from limestone aquifers, as they are only present in the mountains, and sometimes the foothills. There are no non-saline domestic limestone aquifers in the Prairie region.

[76] Wells are found in buried valley aquifers and inter-till aquifers that overlie the bedrock.

direction in which the water flowed. The maps do not cover the entire province and, even where they exist, they may be based on inadequate information as water levels are interpolated where there are large distances between wells. The reliability of the maps depends on the density of the well network, and the amount of hydraulic information obtained for each well.

Alberta Environment collects information for its groundwater database through the reports submitted by water well drillers, but the level of detail provided by the drillers varies. The groundwater database has several problems relating to

- the quality and consistency of the data[77]
- the coordinate system used for the horizontal control
- the distribution of the data.[78]

Despite these limitations the database is often the best information available and it has been used to provide an overview of the groundwater characteristics in many municipalities in the agricultural area of the province. A series of reports, compiled for the Prairie Farm Rehabilitation Administration, describes shallow and deep aquifers and their potential yield, as well as indicating water depth and how it has changed over time.[79] These reports provide a good starting point for those wishing to learn more about their local aquifers, but it must be recognized that they are only as good as the data from which they were compiled and that conditions may have changed.

Water quantity and quality in an aquifer may change for a variety of reasons.[80] Population growth can cause an increase in the rate of withdrawal and local depletion of the aquifer. Climatic variability, either seasonal change or long-term changes such as drought, will also have an impact. Sometimes change in the quality of water in a water well may be due to the fact that the well has aged and not been properly maintained; this can result in high bacteria levels and even the production of methane (see Chapter 6). If water wells have been completed in coal seams, and if the water level in the seams is drawn down (due to drought, an increase in demand or dewatering of the coal to extract CBM), the methane levels in water are likely to increase.

A workshop sponsored by the Canadian Council of Ministers of the Environment identified the importance of learning more about the impact of energy developments on aquifers. “There is a need for ongoing supported surveys of baseline conditions and ongoing monitoring of groundwater quality in both conventional petroleum producing areas and non-conventional energy developments to ensure that once exploration and development occurs, groundwater is not impaired.” [81] The workshop also recognized the need for “baseline hydrogeological

[77] The quality of the data may vary as the reporting requirements have changed over time. For example, one reviewer reports that errors sometimes occurred in estimating the base of groundwater protection.

[78] Agriculture and Agri-Food Canada. 2003. *Wheatland County Regional Groundwater Assessment*. Prairie Farm Rehabilitation Administration. p. 59, *http://www.agr.gc.ca/pfra/water/reports/wland11.pdf*

[79] Agriculture and Agri-Food Canada. Various dates. Prairie Farm Rehabilitation Administration. Groundwater Assessment Reports (Alberta), *http://www.agr.gc.ca/pfra/water/groundw_e.htm*

[80] Gorody, Anthony W. 2005. *What’s in Your Water Well Presentation*, presented at the Northwest Colorado Oil and Gas Forum, November 18, slide 45, “Factors Influencing Changes in Aquifer Yield and Water Quality”, *http://www.oil-gas.state.co.us/Library/library.html* or *http://www.oil-gas.state.co.us/Library/WHAT%20IS%20IN%20YOUR%20WATER%20WELL.pdf*

[81] Crowe, Allan, Karl Schaefer, Al Kohut, Steve Shikaze, Carol Ptacek. 2003. *Groundwater Quality*, p. vii, Canadian Council of Ministers of the Environment. Winnipeg, Manitoba. CCME Linking Water Science to Policy Workshop Series. Report No.2, 52 pages. *http://www.ccme.ca/assets/pdf/2002_grndwtrqlty_wkshp_e.pdf*

investigations in coal-bed methane and exploration frontier areas to be able to recognize and track groundwater contaminants."[82]

The need for more research, monitoring and resources has also been emphasized by the Rosenberg International Forum on Water Policy. It points out that "The existing network of groundwater monitoring is insufficient to provide reliable information on water quality and water levels and their variability."[83] Furthermore, "The development and projected exploitation of oil sands and coal bed methane are likely to pose special threats to both groundwater quantity and quality. These threats will be exacerbated unless both public and private stakeholders remain fully accountable for any adverse environmental consequences that result from their activities."[84]

2.3.2 New research on aquifers

It is essential to improve our knowledge of shallow aquifers that are at risk of impacts from gas development. Various studies are being undertaken to learn more about baseline groundwater conditions, both the volume of water and its quality.

The Alberta Geological Survey has completed a study on the water chemistry of CBM reservoirs. One of the purposes of this study was to "collect geochemical information that could be used in the assessment of the connection between gas-producing and domestic or agricultural water use zones of coalbeds".[85] The data collected "suggests that there is a hydraulic connection between the different portions of the coal-bearing formations on the regional scale"[86] but more research is needed to determine the time scale over which this mixing occurred. Another purpose of the study was "to collect additional data on coal-bearing formation water chemistry to continue to build a baseline dataset as well as to assist development companies better understand the issues surrounding the management of any produced water from these formations." (See section 4.7, below.) The study area extends from north of Edmonton to south of Red Deer. Almost the entire area is underlain by the Horseshoe Canyon Formation and the southwestern half of the area is overlain by the Scollard Formation and the Paskapoo aquifer.

The Paskapoo formation is the uppermost bedrock formation underlying much of Alberta and is the single largest source of groundwater in the Prairies. Over 100,000 wells have been drilled into this formation and 85% of them are between Calgary and Red Deer.[87] Despite its importance as a source of water, much has still to be learned about this aquifer, including its relationship

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[82] Crowe, Allan, Karl Schaefer, Al Kohut, Steve Shikaze, Carol Ptacek. 2003. *Groundwater Quality*, p. 28, Canadian Council of Ministers of the Environment. Winnipeg, Manitoba. CCME Linking Water Science to Policy Workshop Series. Report No.2, 52 pages. http://www.ccme.ca/assets/pdf/2002_grndwtrqlty_wkshp_e.pdf

[83] The Rosenberg International Forum on Water Policy. 2007. *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta,* p.10, http://rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf For information on the Rosenberg International Water Forum on Water Policy see http://rosenberg.ucanr.org/index.html

[84] The Rosenberg International Forum on Water Policy. 2007. *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta,* p.13, http://rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf

[85] Alberta Energy and Utilities Board/Alberta Geological Survey. 2007. *Water Chemistry of Coalbed Methane Reservoirs,* EUB/AGS Special Report 081, p.xvi, http://www.ags.gov.ab.ca/publications/SPE/PDF/SPE_081.pdf

[86] Alberta Energy and Utilities Board/Alberta Geological Survey. 2007. *Water Chemistry of Coalbed Methane Reservoirs*, EUB/AGS Special Report 081, p.xvi, http://www.ags.gov.ab.ca/publications/SPE/PDF/SPE_081.pdf The water chemistry in the shallower coal-bearing formations is the result of mixing between formation water and meteoric water (i.e., from the atmosphere). There is no indication on when this mixing occurred, but it is possible that it "takes place over long time periods with recharge occurring during colder climatic periods." p.xvii. The report indicates (p. 126) that the hydraulic connections between the shallower and deeper portions of the Horseshoe Canyon Formation could be limited or take place over long time periods.

[87] Grasby, Steve. 2004. *Paskapoo Groundwater Study.* Sub-project under the groundwater program on Assessment of Regional Aquifers: Towards a National Inventory, http://ess.nrcan.gc.ca/2002_2006/gwp/p3/a7/index_e.php

with the underlying coal zones and other gas-bearing formations. A three-year groundwater study, led by the Geological Survey of Canada, is being conducted by academics and staff from the provincial and federal government. In this project scientists are working to better understand the hydrodynamic conditions in the formation and to work out the water budgets, that is, how much water flows into and out of the region. They are also examining the relationship between surface water and groundwater.[88]

Figure 2-2 The Paskapoo aquifer in Alberta

Source: Steve Grasby, Geological Survey of Canada (adapted)

Although the Paskapoo formation can be traced across a broad area, it lacks a classical "layer cake" structure, as it was formed by rivers that flowed across the region in geological time. It is also affected by faulting as a result of glacial drag and regional stress patterns associated with mountain building.[89] Permeable sandstone channel remnants may be very continuous along their original (paleo) flow directions but are often separated by low permeability mudstones. Since productive water wells are commonly located in channel sandstone or fracture zones, and these productive zones may represent highly localized preferential flow systems, the yield from water wells may not be representative of the water production for the whole region (since these channels are not in communication with each other).[90]

In part of central Alberta the Paskapoo aquifer is underlain by the Ardley coal zone. In 2006, the Alberta Geological Survey initiated a two-year project to develop hydrogeological maps of the Ardley[91] and the Paskapoo. A suite of geological and hydrological maps will be used to create a risk-based approach to classifying potential CBM drilling locations according to the potential for impact on surface bodies of water or near-surface aquifers.[92] It appears the Ardley coals may

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[88] Some of the findings relate to water quality. Hydrologists find that the water quality in the Paskapoo formation varies from west to east, as does the composition of glacial tills that overlie the aquifers. Two major continental glaciers met over the Paskapoo; the one coming from the east brought quantities of pyrite, which has oxidized to create groundwater with high sulphate levels in the eastern part of the Paskapoo aquifer. Stephen Grasby, Natural Resources Canada, personal communication with Mary Griffiths, October 19, 2006.

[89] Bachu, Stefan and Karsten Michael. 2003. Possible controls of hydrogeological and stress regimes on the producibility of coalbed methane in Upper Cretaceous: Tertiary strata of the Alberta Basin, Canada, *AAPG Bulletin*.2003; 87: 1729-1754, *http://aapgbull.geoscienceworld.org/cgi/content/full/87/11/1729*

[90] For example, it was estimated that channel sands make up less than 24% of the Paskapoo in the uppermost few hundred feet of the formation in the West Nose Creek area. Erick Burns, personal communication with Mary Griffiths, February 14, 2007.

[91] de la Cruz, Nga. 2006. *Coalbed Methane/Natural Gas in Coal and Groundwater,* Alberta Environment Conference, May 2 – 6, slide 27, *http://www.environment2006.com/PDFs/session21b.pdf*

[92] Dean Rokosh, Alberta Geological Survey, personal communication with Mary Griffiths, January 31, 2007.

contain fresh water or saline water, depending on their depth, and that at their eastern limits the coals may be dry, as they are in most of the underlying Horseshoe Canyon formation. It is important to ensure that shallow fracturing in the Ardley (or other shallow gas-bearing formations) does not affect fresh aquifers in the Ardley or create pathways into the Paskapoo aquifer.

While the flows and yields of aquifers are very important, so is the water quality. The Alberta Geological Survey and the Alberta Energy Research Institute have created a public-domain database that gives the chemical analyses of groundwater from water wells in three coal-bearing rock formations: the Paskapoo – Scollard formations, the Horseshoe Canyon Formation and the Belly River Group.[93] The water samples were analyzed for a large range of substances, including hydrocarbon concentrations (and the volatile organic compounds, benzene, toluene, ethylbenzene and xylene), stable isotope composition, radiogenic isotopic composition and naturally occurring radioactive materials. An interactive map based on the data shows not only the location of the wells sampled, but the large number of water wells that are perforated through coal seams.[94]

Research is also underway to learn more about methane that occurs in groundwater. This research is briefly described in Appendix A: Gas Composition and Isotopic Analysis. Isotopic analysis should help distinguish between methane that is created by bacteria in groundwater and methane that has migrated, for example from conventional gas or CBM formations or from the aquifers themselves.

2.4 Monitoring groundwater

The aquifer studies described in the previous section are needed to provide background information, but it is also essential to monitor ongoing changes in aquifers. We need to know not only which areas are recharging groundwater and the linkages between different aquifers, but also whether any changes in the recharge areas have occurred that may have altered the recharge rate since earlier decades. Changes in groundwater direction or velocity can be effectively studied only through a network of monitoring wells at sufficient density—a density that will depend on the scale of the aquifer. This will allow investigation of the impact that demand and drought has had on groundwater in the past, and how changes in river flows and wetland areas may affect fresh water aquifers in the future. However, it can be complicated to accurately determine the long-term yield of an aquifer, especially as this can be impacted by reductions in recharge (e.g., from reduced runoff) and unmeasured withdrawals from the aquifer. Currently, most monitoring is related to industrial development, and is usually required in a company's licence to operate. Alberta Environment monitors both groundwater quantity and quality, but it does it not have a high density of monitoring wells at the present time. This lack of background stations makes it hard to track natural variations in groundwater within the province, such as the impacts of climate change on groundwater levels.[95]

Water levels are measured in approximately 200 wells[96] in Alberta's groundwater observation well network (GOWN).[97] The wells are concentrated in the settled area of the province, but there

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[93] Alberta Geological Survey. 2005. *Shallow Coal Aquifer Water Chemistry,* http://www.ags.gov.ab.ca/activities/CBM/shallow_coal.shtml

[94] Alberta Geological Survey. *Alberta GIS and Inter-active Maps, http://www.ags.gov.ab.ca/GIS/gis_and_mapping.shtml*

[95] Steve Grasby, Natural Resources Canada, personal communication with Mary Griffiths, January 10, 2007.

[96] The location of the water wells can be seen in Alberta Environment. 2006. *Protecting Alberta's Groundwater,* slide 11, *http://www.waterforlife.gov.ab.ca/coal/docs/Protect_GW.pdf*

are many gaps and deficiencies in the system. According to a consultant's report, "in the past, due to budgetary constraints, [Alberta Environment] has had to curtail its groundwater monitoring activities."[98] As revealed in that same report, "Lack of monitoring wells in Northern Alberta, as well as in the major regional units/aquifers like the Paskapoo Formation, Horseshoe Canyon Formation, Belly River Formation, Bearpaw Formation, Oldman Formation and Milk River Formation, is clearly evident."[99] Several of the named formations are in central and southern Alberta, where there is much production of gas and also heavy use of aquifers due to high population density.

The consultant's report notes: "Considering the size of Alberta, climatic conditions, populations distribution and level of development, the number of monitoring wells established is comparatively small."[100] In the early 1990s, Alberta had approximately 400 wells in service to monitor groundwater levels.[101] While that number has since been halved, the province of Manitoba has maintained its network of approximately 600 groundwater monitoring wells.[102] The monitoring wells in Alberta are located primarily in agricultural areas,[103] but a much denser network of monitoring wells is required in Alberta if changes in water levels in local aquifers are to be identified. If the monitoring wells currently in the GOWN system were distributed evenly across the province, there would be only one well for every 3,000 square kilometres. It is essential to improve knowledge of Alberta's groundwater to ensure this resource is not over-allocated. Although it is a renewable resource, if demand exceeds the rate of recharge, aquifers become depleted to such an extent that they will no longer provide a viable source of water.

Excessive withdrawals not only impact the depth of groundwater, but can lead to mixing of poorer quality water, affecting the overall water quality.[104] Thus monitoring of groundwater quality is also essential. There were approximately 240 wells in the Provincial Ambient Groundwater Quality Network in 2005, about 80 fewer than in the early 1990s.[105] Sampling was

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[97] Alberta Environment's Groundwater Observation Well Network, *http://www3.gov.ab.ca/env/water/gwsw/quantity/waterdata/gwdatafront.asp* In 2005 the number of wells was approximately 172. The main network is supplemented with manual measurements taken several times a year from about 200 project wells, while approximately 100 additional shallow stainless steel wells are monitored for groundwater quality every few years. Alberta Environment, personal communication with Mary Griffiths, September 2005.

[98] Komex International Ltd. 2005. *Groundwater Monitoring Networks Master Plan Development: Final Report,* p. 36. Prepared for Alberta Environment. See also p. 20: "In the early 1990s there were 400 observation wells with computerized water level data, and approximately 200 of these are still periodically monitored."

[99] Komex International Ltd. 2005. *Groundwater Monitoring Networks Master Plan Development: Final Report,* p. 34. Prepared for Alberta Environment.

[100] Komex International Ltd. 2005. *Groundwater Monitoring Networks Master Plan Development: Final Report,* p. 34. Prepared for Alberta Environment.

[101] Komex International Ltd. 2005. *Groundwater Monitoring Networks Master Plan Development: Final Report,* p. ii. Prepared for Alberta Environment.

[102] Betcher, Robert, Gary Grove and Christian Pugg.1995. *Groundwater in Manitoba: Hydrogeology, Quality Concerns, Management,* National Hydrology Research Institute Report, Environment Canada, p. 37, *http://www.gov.mb.ca/waterstewardship/reports/groundwater/hg_of_manitoba.pdf* The number of monitoring wells in Manitoba is approximately the same as in 1995. Eric Carlson, Groundwater Data Supervisor, Manitoba Water Stewardship, personal communication with Mary Griffiths, August 3, 2006.

[103] Alberta Environment. 2006.*Groundwater and Coalbed Methane Information Sessions. Protecting Alberta's Groundwater during Coalbed Methane Development,* slide 11, *http://www.waterforlife.gov.ab.ca/coal/docs/Protect_GW.pdf*

[104] Excessive withdrawals may also have another impact. "In some instances, lowering of the groundwater surface may trigger aeration of a portion of a previously saturated aquifer. Aeration or cyclic aeration may lead to unfavourable hydrochemical changes (e.g., dissolution of metals). Under this scenario, water may require expensive treatment prior to distribution for domestic use, and long-term availability may also be reduced." Komex International Ltd. 2005. *Groundwater Monitoring Networks Master Plan Development: Final Report,* p. 48. Prepared for Alberta Environment. The over-exploitation referred to in the citation is different from the natural annual cycle in an unconfined aquifer.

[105] This is still the approximate number of wells in the system in 2006. Alberta Environment, personal communication with Mary Griffiths, August 10, 2006.

supposed to be conducted each year until the quality was found to be stable, and then once every five years. However, "Budget and manpower priorities shifted and the schedule was not maintained."[106] As a result, "the existing groundwater monitoring system does not offer an adequate coverage of major aquifers most vulnerable to groundwater contamination."[107] With so few monitoring wells, there is little chance that point sources of contamination will be identified. Alberta Environment has initiated enhanced sampling of existing monitoring wells and the addition of new wells to the provincial network but much more needs to be done. The report of the Rosenberg International Water Forum points out that, "Monitoring networks need to be maintained over time and be sufficiently dense to allow trends to be measured and analyzed and to permit early detection of contamination episodes."[108]

While the potential introduction of contaminants into shallow aquifers as a result of exploration, drilling and production is often a focus of concern, it is also essential to ensure that waste (such as produced saline water or other forms of waste) that is intentionally injected into deep aquifers does not contaminate shallow groundwater. It is worth noting that injection of very large volumes of water into deep saline aquifers has been carried out for many years.[109] Provided the aquifers are deep enough and not in communication with non-saline aquifers, this should not be an issue in the central and southern Alberta.[110]

[106] Komex International Ltd. 2005. *Groundwater Monitoring Networks Master Plan Development: Final Report,* p. 20. Prepared for Alberta Environment.

[107] Komex International Ltd. 2005. *Groundwater Monitoring Networks Master Plan Development: Final Report,* p. 49. Prepared for Alberta Environment.

[108] The Rosenberg International Forum on Water Policy. 2007. *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta,* p.10, *http://rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf*

[109] "In 2003 1.7 billion barrels of produced water was injected into disposal wells associated with oil and gas production in Alberta." Hum, Florence, Peter Tsang, Thomas Harding and Apostolos Kantzas. 2005. *Review of Produced Water Recycle and Beneficial Reuse.* Institute for Sustainable Energy, Environment and Economy. University of Calgary, p.1. This volume of water, 1.7 billion barrels, is equivalent to 270 million m^3.

[110] Everywhere in the province, the disposal zone must be below the base of groundwater protection and "all applications for disposal above 600 metres receive additional scrutiny to ensure disposal is not occurring in close proximity to a non-saline water aquifer." Alberta Energy and Utilities Board. 2006. Untitled document giving responses to questions asked at Alberta Environment public information sessions on CBM, *http://www.waterforlife.gov.ab.ca/coal/docs/EUB.pdf* See also *http://www.waterforlife.gov.ab.ca/coal/index.html* A company applying for a licence must confirm the disposal zone is saline and the EUB requires monitoring of the disposal zone and the next overlying porous zone, to ensure containment. However, it has been recognized that "More research is needed to characterize the hydrologic connection between disposal formations and shallow aquifers/surface water. For example, will the streams of northeast Alberta become affected by deep-well disposal of oil-sand wastewater?" Crowe, Allan, Karl Schaefer, Al Kohut, Steve Shikaze, Carol Ptacek. 2003. *Groundwater Quality,* p. 28, Canadian Council of Ministers of the Environment. Winnipeg, Manitoba, CCME Linking Water Science to Policy Workshop Series. Report No.2, 52 pages. *http://www.ccme.ca/assets/pdf/2002_grndwtrqlty_wkshp_e.pdf*

3. Conventional Gas, Coalbed Methane, Shale Gas and Tight Gas

This chapter describes the characteristics of the different sources of natural gas, how each type of production may potentially affect water and Alberta government regulations that aim to protect water resources. We start with conventional gas, then look at unconventional gas sources: CBM, shale gas and tight gas. Much of the information on conventional gas, especially the way in which the EUB regulates it, also applies to unconventional gas. After examining the distinctive characteristics of various forms of natural gas production in this chapter, Chapter 4 provides more detail on the various processes associated with well drilling, stimulation, and so on, which are often similar for different types of gas production. We hope that both chapters will help landowners understand the issues so they can ask the right questions about new developments planned for their land and, when appropriate, negotiate for best management practices.

3.1 Conventional gas

3.1.1 What is conventional gas?

Conventional gas is natural gas found in pore spaces in porous formations such as sandstone or limestone. It is mainly composed of methane, but may also contain some heavier hydrocarbons, such as ethane, propane and butane, and small quantities of other hydrocarbons.[111] Natural gas usually contains some nitrogen, carbon dioxide and water and may also contain hydrogen sulfide (the gas that makes gas "sour").

Gas found at depths between 200 and 1,000 metres in the Canadian plains is often called shallow gas.[112] Recent work by the Alberta Geological Survey indicates that conventional shallow gas is present at economic levels in some areas of thick glacial drift in northern Alberta.[113] In parts of the province, such as the shallow sandstones and carbonates in southern Alberta, some geologists classify gas in shallow zones as unconventional gas (see section 3.4.1 in the section on tight gas).

3.1.2 How can conventional gas development affect water?

The use of water for well drilling and stimulation, and the potential impacts on shallow aquifers, are described in Chapter 4, since these activities are common to all types of gas production.

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[111] Centre for Energy. 2007. *Natural Gas: Overview. What is Natural Gas?* http://www.centreforenergy.com/silos/ong/ET-ONG.asp

[112] Pederson, Kent. 2006. *Unconventional Shallow Gas – A Geological Point of View*. Abstract for a presentation given to the Canadian Society of Professional Geologists, Calgary, September 7, http://www.cspg.org/events/luncheons/events-luncheon-20060907.cfm The gas is usually found in low permeability sandstones, thin-bedded sandstones and sandstones containing some clay, which helps to keep the gas in the formation.

[113] Pawlowciz, J.G., T. Berezniuk and M. Fenton. 2003. *Quaternary Gas in Northern Alberta: Drift/Glacial Sediment Characteristics and Geometry (A Presentation to the SCPG Annual General Meeting).* EUB/AGS Information Series 127, http://www.ags.gov.ab.ca/publications/pdf_downloads/conference_posters/Shallow_gas_talk.pdf

When a conventional gas well starts producing, gas will flow into the wellbore. There can be mobile water in a formation under the gas "cap," which is found at the top of the formation. As the gas is depleted, the reduction in pressure allows water at the bottom of the formation to become mobile and be pulled up into the gas cap. Thus as a gas well ages, some water may be produced with the gas. When this water comes from deep formations it is saline and, if the well produces sour gas, may also contain some hydrogen sulphide. The water is separated from the gas at the wellhead and sent for re-injection into a deeper formation (see section 4.4).

Initially, natural gas in Alberta was produced from conventional sources in formations with large volumes of high-pressure gas accumulated in the pore space of carbonate and sandstone formations. As these formations were generally deeper than the base of groundwater protection,[114] there was little risk of an impact on fresh water aquifers. However, companies now also drill for gas in low pressure, shallower formations, which are much closer to the surface and potentially above the base of groundwater protection. (These shallower formations may also include coal beds that contain gas adsorbed onto the coal; see section 3.2.2 for more information). Although geologists and engineers do not think that gas production from shallow sandstone reservoirs and coal beds is likely to cause problems, one consultant is concerned that, when gas is produced, some water could gradually infiltrate from fresh water aquifers if there is any connectivity. Ultimately this may be the case until a new state of pressure equilibrium is reached, but the main issues to be considered are the size and time scale of this process. This is discussed in section 4.4.1.

3.1.3 What are the government regulatory programs for conventional gas?

3.1.3.1 General EUB requirements for wells, facilities and pipelines

The EUB regulates all aspects of natural gas production in Alberta, with the exception of the protection of groundwater, which is also under the jurisdiction of Alberta Environment.[115] The EUB and Alberta Environment work together on issues relating to fresh groundwater protection. When a company applies for a licence, for example, to drill a well or construct a pipeline, it must meet all the requirements set out in EUB *Directive 56: Energy Development Application and Schedules.* This directive includes many references to the protection of fresh water bodies[116] and usable groundwater.[117] Under EUB requirements set out in *Directive 56* and other directives, a company must do the following:

- Notify or consult landowners close to a well or pipeline.[118] During this process it is expected to provide information that will help landowners understand the requirements that will affect them, e.g., with respect to water well testing.[119]

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[114] See Appendix B: Glossary.

[115] The EUB also has a mandate that includes water. See *Oil and Gas Conservation Act,* various sections, including section 37 on the disposal of water, *http://www.qp.gov.ab.ca/documents/Acts/O06.cfm?frm_isbn=0779747577*

[116] Alberta Energy and Utilities Board. 2005. *Directive 056: Energy Development Application and Schedules (September 2005),* Figure 3.1, p.16. *http://www.eub.ca/docs/documents/directives/directive056.pdf* Facilities must be set back from water bodies by a minimum of 100 metres (Section 5.9.10, p. 55)

[117] Alberta Energy and Utilities Board. 2005. *Directive 056: Energy Development Application and Schedules (September 2005),* Section 7.9.9, p. 176, *http://www.eub.ca/docs/documents/directives/directive056.pdf*

[118] Alberta Energy and Utilities Board. 2005. *Directive 056: Energy Development Application and Schedules (September 2005),* Section 2, p. 5, *http://www.eub.ca/docs/documents/directives/directive056.pdf* The required notification distance varies, but is often 200 metres for pipelines (Table 6.1, p. 106 in the Directive). Landowners and occupants along the right of way must be consulted. For wells, the notification and

- In its application for a gas well, include a survey plan that shows the topography and any water bodies and water wells located within 200 metres of the proposed gas well.[120]
- Meet setback requirements, such as drilling a well at least 100 metres from a water body (including seasonal or intermittent streams, all types of wetland and human-made drainage ditches and dugouts), or explain how the water body will be protected if the setback is not met.[121]
- Ensure that water bodies are protected during drilling and operations (by using an impermeable berm, vacuum truck, or some other method).[122]
- Check on the depth of usable groundwater and follow specific requirements for casing a well above the base of groundwater protection.[123] Further details on casing requirements are given in *Directive 8.*[124] The surface casing interval on all new wells must be logged to provide additional information on shallow aquifers and help in the evaluation of any potential impact from gas or oil activity, as set out in *EUB Directive 43.*[125]
- Inform the EUB whether it has met Alberta Environment's Environmental Protection Guidelines and all requirements with respect to the Code of Practice under the *Water Act.*[126] A company must also comply with federal legislation relating to water, including the *Navigable Waters Protection Act* and the *Fisheries Act.*[127]
- Regularly patrol pipeline right-of-ways and produced water lines to detect leaks.[128]
- Handle and store all substances to prevent contamination of fresh water. This includes specific requirements for the handling of produced water, which is most frequently saline.

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consultation distance may be only 100 metres; see Table 7.1, p.163. Notification is required for greater distances when a well or pipeline contains sour gas and the potential release rate exceeds specified levels.

119 Alberta Energy and Utilities Board. 2005. *Directive 056: Energy Development Application and Schedules (September 2005),* Section 2.2, p. 9, *http://www.eub.ca/docs/documents/directives/directive056.pdf* Chapter 2 sets out all the general requirements for public consultation. The actual distances within which a company must notify or consult with landowners are set out in separate tables, e.g., Tables 5.1, 6.2 and 7.1.

120 Alberta Energy and Utilities Board. 2005. *Directive 056: Energy Development Application and Schedules (September 2005),* Section 7.9.1, p. 166-167, *http://www.eub.ca/docs/documents/directives/directive056.pdf*

121 Alberta Energy and Utilities Board. 2005. *Directive 056: Energy Development Application and Schedules (September 2005),* Section 7.10.11.1, p. 199, *http://www.eub.ca/docs/documents/directives/directive056.pdf*

122 Alberta Energy and Utilities Board. 2005. *Directive 56: Energy Development Application and Schedules (September 2005),* Section 7.9.12.1, p. 181, *http://www.eub.ca/docs/documents/directives/directive056.pdf*

123 Alberta Energy and Utilities Board. *Directive 56: Energy Development Application and Schedules (September 2005),* Section 7.9.10, p. 176, *http://www.eub.ca/docs/documents/directives/directive056.pdf* Companies refer to an EUB CD entitled *ST-55 Alberta's Usable Groundwater Base of Groundwater Protection Information*

124 Alberta Energy and Utilities Board. 1997. *Directive 008: Surface Casing Depth Minimum Requirements, http://www.eub.ca/docs/documents/directives/directive008.pdf* A company can obtain a waiver to *Directive 008* if they file a non-routine application. See *Directive 56,* Section 7.9.10, p. 176

125 Alberta Energy and Utilities Board. 2006. *Directive 043: Well Logging Requirements – Surface Casing Interval, http://www.eub.ca/docs/documents/directives/directive043.pdf*

126 Alberta Energy and Utilities Board. 2005. *Directive 056: Energy Development Application and Schedules (September 2005),* p. 150, *http://www.eub.ca/docs/documents/directives/directive056.pdf*

127 Alberta Energy and Utilities Board. 2005. *Directive 056: Energy Development Application and Schedules (September 2005),* Section 7.9.12.1, p. 184, *http://www.eub.ca/docs/documents/directives/directive056.pdf*

128 Alberta Energy and Utilities Board. 2005. *Directive 056: Energy Development Application and Schedules (September 2005),* Section 6.9.3, p. 112, *http://www.eub.ca/docs/documents/directives/directive056.pdf*

Provisions may include containment of the storage location, such as with a dyke to limit contamination from leaks or spills.[129]

- Report the volume of water produced with the gas.[130] *Directive 44* requires a company to closely monitor production of water from gas (and oil) wells completed above the base of groundwater protection; if the volume of non-saline water exceeds 5 m^3/month it must notify the EUB.[131] The company must then determine the source and composition of the water and prepare a mitigation plan (which might involve ending production from the zone above the base of groundwater protection). The mitigation plan must be approved by the EUB and Alberta Environment. This directive also reminds companies that they need a diversion permit from Alberta Environment for the production of non-saline water.
- Dispose of produced water so that it does not harm the environment. The EUB normally requires produced water to be disposed of by injection into a disposal well.[132, 133] However, Alberta Environment is considering whether to allow the beneficial use of produced water from CBM wells, if protection of the surface environment can be ensured (see sections 3.2.3 and 4.7). [134]
- Ensure that when a well is abandoned (i.e., closed down at the end of its life) all non-saline water zones are covered by cement and the base of groundwater protection is protected from zones containing hydrocarbons.[135]

All EUB directives include a surveillance and enforcement component. Failure to provide adequate groundwater protection is a major offence, as is failure to meet or address the setback requirements for water bodies.[136]

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[129] Alberta Energy and Utilities Board. 2001. *Directive 055: Storage Requirements for Upstream Petroleum Industry*, Section 5.2, *http://www.eub.ca/docs/documents/directives/Directive055.pdf* The requirements apply if the tank for storing water has a capacity of more than 5 m^3. There is an exemption for secondary containment for specified storage containers of less than 30 m^3, for produced water from the Milk River, Medicine Hat and Second White Specks pools (see Section 3.4.1); these pools usually have relatively low salinity water. Surface runoff from within the containment area can be released to the environment, if it is not contaminated (see Chapter 11 in the EUB directive).

[130] Alberta Energy and Utilities Board. 2005. *Directive 056: Energy Development Application and Schedules (September 2005),* Section 5.9.13, p. 58, *http://www.eub.ca/docs/documents/directives/directive056.pdf*

[131] Alberta Energy and Utilities Board. 2006. *Directive 044: Requirements for the Surveillance, Sampling and Analysis of Water Production in Oil and Gas Wells Completed Above the Base of Groundwater Protection, http://www.eub.ca/docs/documents/directives/directive044.pdf* The EUB has developed a mechanism to identify wells that may fall in the >5 m^3/month category, and is notifying companies that testing is required. A company must identify and test the water, even if they plan to abandon the zone.

Other directives dealing with water production include: Alberta Energy and Utilities Board. 2004. *Directive 004: Determination of Water Production at Gas Wells, http://www.eub.ca/docs/documents/directives/Directive004.pdf* and Alberta Energy and Utilities Board. 2001. *Directive 007: Production Accounting Handbook, http://www.eub.ca/docs/documents/directives/directive007.pdf* Although a company must normally report the water production from each well, in this directive the EUB waives the reporting of water production from individual shallow gas wells in southeastern Alberta.

[132] *Oil and Gas Conservation Act,* section 37. See also Alberta Energy and Utilities Board. 1994. *Directive 051: Injection and Disposal Wells, http://www.eub.ca/docs/documents/directives/Directive051.pdf*

[133] The EUB no longer allows a company to dispose or inject water produced from shallow-gas-bearing formations back into the zone of origin or other shallow zones. Alberta Energy and Utilities Board. 2000. *General Bulletin: GB 2000-8: Process Changes to Disposal Well Applications, http://www.eub.ca/docs/ils/gbs/pdf/gb2000-08.pdf*

[134] Government of Alberta. 2006. *Coalbed Methane/Natural Gas in Coal Multi-Stakeholder Advisory Committee Final Report,* recommendation 3.5.1, *http://www.energy.gov.ab.ca/docs/naturalgas/pdfs/cbm/THE_FINAL_REPORT.pdf*

[135] Alberta Energy and Utilities Board. 2003. *Directive 020: Well Abandonment Guide,* Section 5.3, p. 27, *http://www.eub.ca/docs/documents/directives/Directive020.pdf*

[136] Alberta Energy and Utilities Board. 2005. *Directive 056: Energy Development Application and Schedules (September 2005),* Table 4.1, p. 36, *http://www.eub.ca/docs/documents/directives/directive056.pdf* The penalties are set out in Alberta Energy and Utilities Board. 2005. *Directive 019: Compliance Assurance – Enforcement, http://www.eub.ca/docs/documents/directives/Directive019.pdf*

3.1.3.2 Alberta Environment requirements

The *Water Act* determines when a licence is required to use water, but the details are set out in the *Water (Ministerial) Regulation.* Companies must have a licence to use fresh water, but the use of saline water is exempt under the regulation.[137] Thus a company must usually obtain a licence to use water from a river or fresh groundwater for drilling a well or fracturing, but there are some exemptions (e.g., a licence is not required to use water from a dugout if certain conditions are met).[138]

Anyone wishing to divert groundwater from above the base of groundwater protection must also obtain a diversion licence from Alberta Environment.[139] The department did not require a licence for diversion of water from conventional gas wells as traditionally they were deep and contained saline water. In recent years more gas wells have been completed in shallow formations that may produce fresh water. Alberta Environment plans to develop a process that will apply to water production from shallow gas wells, but at the time of writing this is not yet in place.

The *Environmental Protection and Enhancement Act*, which prohibits the release of substances that may cause adverse effects to the environment, is used to protect water from contamination.[140] Most produced water is saline and is sent for injection in a disposal well (see section 3.1.3.1, above).[141] If the chemical composition is compatible, water may be injected back into the aquifer from which it was diverted, but at some distance from the production area, or into a different aquifer containing groundwater of lesser quality.[142] If water is re-injected to recharge a non-saline aquifer, it must be authorized under the *Water Act.*[143]

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[137] Government of Alberta. 2000 and updates. *Water Act*, *http://www.qp.gov.ab.ca/catalogue/catalog_results.cfm?frm_isbn=0779727428&search_by=link* See also the *Water (Ministerial) Regulation*, , section 5 and Schedule 3, section 1(e), *http://www.qp.gov.ab.ca/documents/Regs/1998_205.cfm?frm_isbn=0779750764*

[138] Government of Alberta. 2000 and updates. *Water (Ministerial) Regulation*, section 5 and Schedule 3, section 1(c), *http://www.qp.gov.ab.ca/documents/Regs/1998_205.cfm?frm_isbn=0779750764*

[139] Alberta Environment. 2003. *Groundwater Evaluation Guideline (Information Required when Submitting an Application under the Water Act)*, *http://environment.gov.ab.ca/info/library/7508.pdf* Special requirements for CBM wells that produce fresh water are described in the next section.

[140] Government of Alberta. 2000 and updates, *Environmental Protection and Enhancement Act*, *http://www.qp.gov.ab.ca/catalogue/catalog_results.cfm?frm_isbn=0779748611&search_by=link* See especially Part 5 Release of Substances and the accompanying regulation, *Substance Release Regulation*, *http://www.qp.gov.ab.ca/documents/Regs/1993_124.cfm?frm_isbn=0779746325*

[141] It should be noted that at the time of writing, there is no provision for the disposal of produced water to the surface. Only surface run-off may be released to surface waters if it meets the required standards. Alberta Environment. 1999. *Surface Water Quality Guidelines for Use in Alberta*, *http://environment.gov.ab.ca/info/library/5713.pdf* Table 1 gives guidelines for fresh water aquatic life; Table 2 gives the guidelines for irrigation and livestock. The Guidelines form the basis for the discharge of wastewater and the limits are incorporated into the approval for a specific project issued under the *Environmental Protection and Enhancement Act*, which means they can be enforced.

[142] Alberta Environment, personal communication with Mary Griffiths, 2003.

[143] At present Alberta Environment requires an approval only for the re-injection of non-saline water. The Department interprets re-injection as part of the process of diversion and points out that the diversion of saline water is exempted by the *Water (Ministerial) Regulation.* They indicate that the *Environmental Protection and Enhancement Act* would allow them to take action if a company damaged a non-saline aquifer or caused other impacts during the re-injection process. However, it can be argued that any re-injection that could disturb water is an “activity” under the *Water Act* and should require an approval unless the activity is specifically exempted by the regulations.

3.2 Coalbed methane

3.2.1 What is coalbed methane?

Coalbed methane (CBM) is known by various names, including natural gas in coal and natural gas from coal.[144] The EUB provides an overview of CBM in its brochure, *EnerFAQs 10: Coalbed Methane*.[145]

Coal was formed by the effects of heat and pressure on buried plant materials over millions of years.[146] During this process methane was formed. CBM often contains about 95% methane, with small volumes of nitrogen and carbon dioxide and other gases. Much of the methane gas is adsorbed, or bonded, to the internal surfaces of the coal at a molecular level where it is held in place by the pressure of the overlying rocks and by water in the coal seams. Methane is also stored in natural fractures in the coal, called cleats.[147] Because of these many surfaces, when coal is fully saturated with methane, the volume of gas it contains may be up to 28 times the volume of the coal at standard conditions.[148]All coals, no matter what the depth, contain methane in their internal structure. They possibly contain tiny volumes of ethane, propane, and butane that are only isotopically detectable.[149]

Much CBM was formed as a result of heat and pressure (thermogenic methane), but it can also be formed by bacteria (biogenic methane). The Alberta Geological Survey has found that the age of the groundwater in coal seams varies widely and in some rock units the water might have been recharged in relatively recent geological time.[150] It also found that "microbiological communities exist within these rock units that may be responsible for the generation of methane."[151] Scientists at Alberta Research Council are currently investigating coals to determine whether biogenic methane can be produced on a sustainable basis.[152]

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[144] Although coalbed methane is the term used in the U.S. and was used in early reports in Alberta, in 2003 the Canadian Association of Petroleum Producers advocated for a change in name from coalbed methane to "natural gas from coal". They felt that this would "… more accurately reflect that coalbed methane is simply a form of natural gas and will be developed in a similar manner." *Natural Gas from Coal in Alberta: Position Paper prepared for the Canadian Association of Petroleum Producers,* p. 2, http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=72435 In this paper (p. 7) CAPP states that the government should continue to regulate CBM in the same way as natural gas, except to comply with their recommendations, which relate to tenure and fiscal matters as well as regulatory issues.

[145] Alberta Energy and Utilities Board. 2004. *EnerFAQs 10: Coalbed Methane,* http://www.eub.ca/portal/server.pt/gateway/PTARGS_0_0_281_237_0_43/http%3B/extContent/publishedcontent/publish/eub_home/public_zone/eub_process/enerfaqs/enerfaqs10.aspx

[146] Trident Exploration Corp. *How is Natural Gas from Coal Created?* http://www.tridentexploration.ca/displaylinkngc.asp?LinkID=10&Submit=Go

[147] The Canadian Society for Unconventional Gas website provides an overview of coalbed methane at http://www.csug.ca/faqs.html

[148] Eltschlager, Kenneth K., Jay W. Hawkins, William C. Ehler, Fred Baldassare. 2001. *Technical Measures for the Investigation and Mitigation of Fugitive Methane Hazards in Areas of Coal Mining,* p.23. U.S. Department of the Interior, Office of Surface Mining, http://www.osmre.gov/pdf/Methane.pdf

[149] Isotopic data shows that, in addition to methane, coals contain very small percentages of ethane, propane and butane. The volumes are so small that they may not be apparent in the compositional analysis of the gas. However, if a water well is completed in a coal seam, a landowner may see reference to ethane, propane or butane in the isotopic analysis of the well water.

[150] The Alberta Geological Survey work was done on coal seams in water wells. As the coals are shallow one would expect to see thermogenic methane formed with the coal deep underground and biogenic methane related to the current shallow stratigraphic position. (Coal seams were formed at depth, but may now be near the surface, due to erosion of the overlying sedimentary rocks.)

[151] Lemay, Anthony. 2006. *Water Chemistry of Coalbed Methane Reservoirs,* Canadian Society of Petroleum Geologists, Canadian Society of Exploration Geophysicists and Canadian Well Logging Society, Joint Conference, Calgary, May 15-18, 2006, http://www.geoconvention.org/sessions/cspg-unconventional-gas.asp Scientists at Alberta Research Council are currently investigating the generation of biogenic methane in coal seams.

[152] Budwill, Karen. 2006. *Role of Biogenic Gas Generation for Sustainable CBM Production,* Williston Basin Petroleum Conference, May 7 – 9, http://www.state.nd.us/ndgs/wbpc/pdf/Karen_Budwill.pdf

There are several formations containing coal in Alberta, as shown in Figure 3-1.

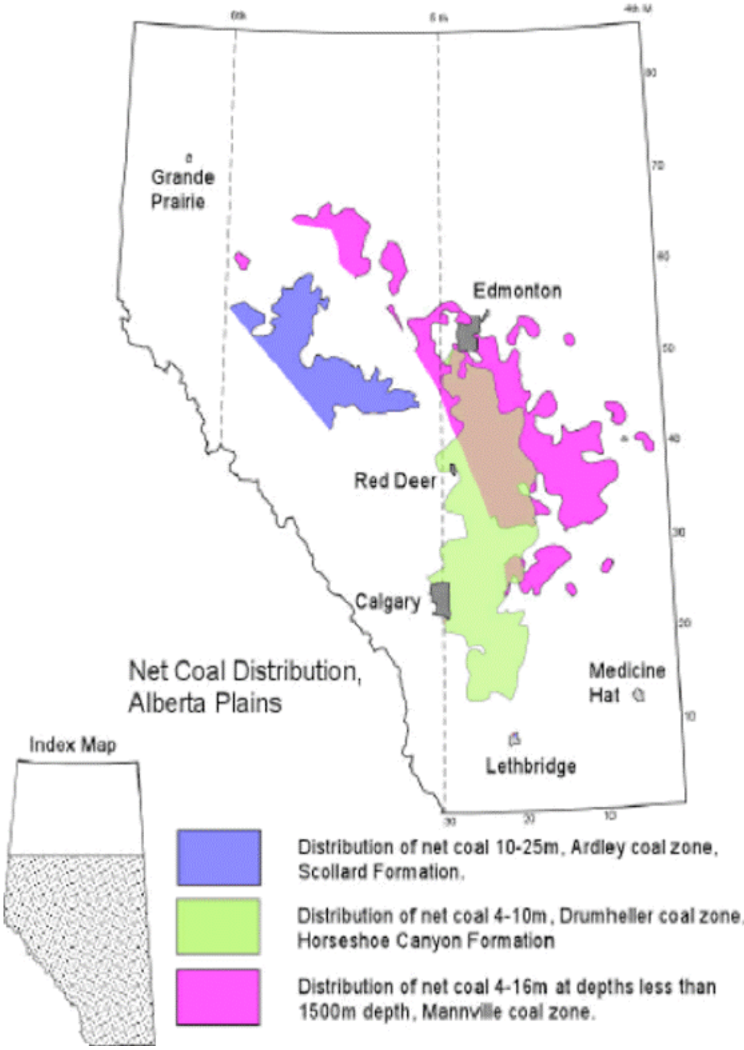

Figure 3-1 Main coalbed methane target areas in Alberta

Source: Alberta Energy and Utilities Board

The characteristics of the coal vary with its age and depth. Although methane gas is often held in place by the water in the formation, the volume of water in coal seams varies enormously. Some coal zones are predominantly dry, especially in the Horseshoe Canyon.[153] The formations across central Alberta dip (become deeper) towards the west, but are thrust up towards the surface against the mountains (see Figure 3-2).

[153] Bedard, Adam. Norwest Corporation. 2005. *CBM Water Management Case Study*, Petroleum Technology Alliance Canada 2005 Water Efficiency and Innovation Forum, June 23, Calgary, *http://www.ptac.org/env/dl/envf0502p15.pdf* Slide 6 compares the average gas and water production from CBM wells in Alberta (Horseshoe Canyon and Mannville Coals) with several CBM basins in the U.S.

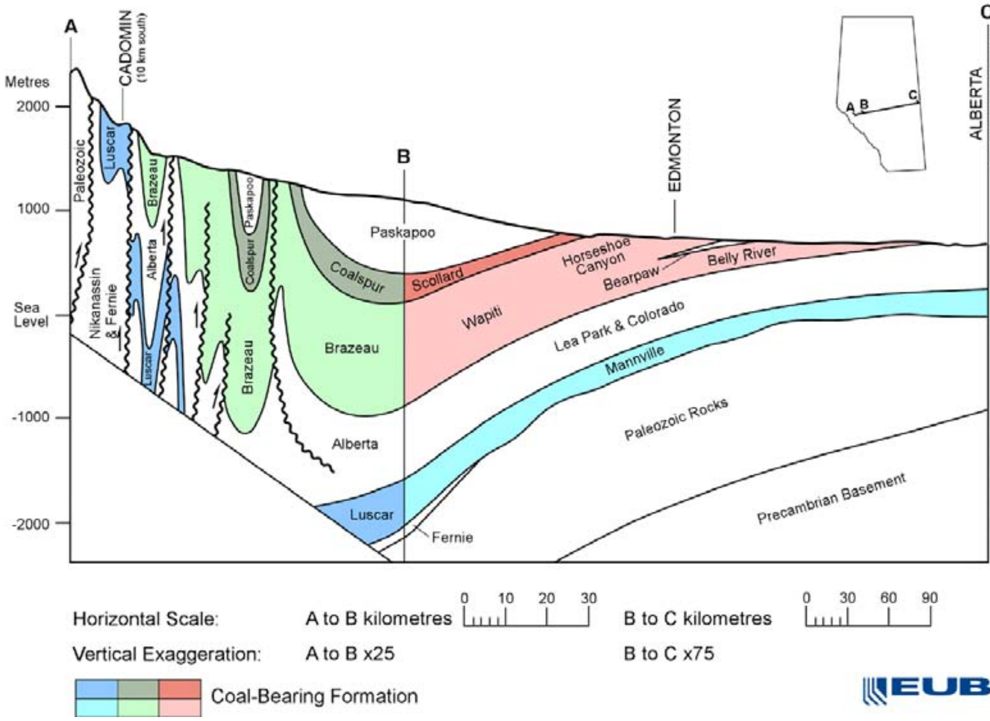

Figure 3-2 Representative cross-section showing Central Alberta's significant coal bearing formations

Source: Alberta Energy and Utilities Board/Alberta Geological Survey

Coal seams may vary in thickness from a few centimetres to several metres.[154] There are usually a number of seams in a zone and a number of coal zones within each formation or group, as can be seen from Figure 3-3. The coal seams within a formation may be grouped into a single "pool"[155] and a company can produce from many seams or even from more than one pool at the same time. This practice is referred to as "commingling." The EUB has special requirements if a company commingles production from two or more zones or pools (see section 4.6).

[154] The geological description of the Mannville coals: "Typically six or more seams with cumulative coal thickness ranging from 2 to 14 metres occur over a stratigraphic interval of 40 to 100 metres." Alberta Geological Survey. 2005. *Alberta Coal Occurrences and Potential Coalbed Methane (CBM) Areas,* http://www.ags.gov.ab.ca/activities/CBM/coal_and_cbm_intro.shtml

[155] Alberta Energy and Utilities Board. 2006. *Bulletin 2006-16: Commingling of Production from Two or More Pools in the Wellbore.* See p.20, Appendix 7, for Criteria for Designating CBM Pools, http://www.eub.ca/docs/documents/bulletins/Bulletin-2006-16.pdf "The EUB is establishing a number of separate CBM pools by defining the vertical and lateral extent. The vertical extent of a CBM pool is based on stratigraphy and is defined by the EUB as all seams in a geological formation unless separated by more than 30 m of non-coal-bearing strata or separated by a conventional gas pool … Because coal zones can extend for great lateral distances, the lateral extent of a CBM pool is established by the EUB as an administratively manageable area, usually corresponding to a field boundary. In some situations, there may be more than one CBM pool within a field or a CBM pool may extend beyond a single field (a multifield pool)." The reference includes figures and further explanation.

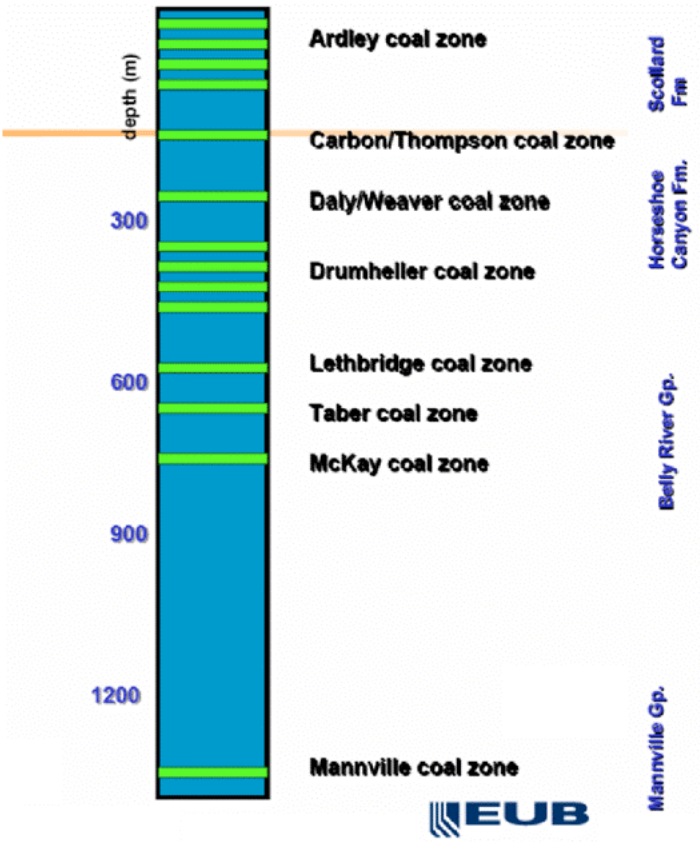

Figure 3-3 Generalized coal zone stratigraphy, Alberta Plains

Source: Alberta Energy and Utilities Board

By the end of 2006 there were 10,723 gas wells in Alberta that had been drilled or recompleted for CBM.[156] More than 9,700 of these wells were in the Horseshoe Canyon/Belly River Formations, where the focus has been on the dry coals. The area where the resource is "developable" is estimated to extend to about 14,500 sections, or 9.3 million acres.[157] In July 2005 the first companies announced commercial production in the Mannville Formation, and by the end of 2006 over 800 wells had been drilled in the Mannville coals. However, there are no definitive estimates of the reserves here. The location of wells as at the end of 2005 is shown in Figure 3-4.

CBM will often require a higher density of wells than is needed to produce conventional natural gas.[158] As a result, where coal seams are wet there may be four to eight CBM wells producing water per section (which is one or two wells per 160 acres). This well density is likely with CBM wells producing above the base of groundwater protection. If a company is drilling for CBM

[156] Alberta Energy and Utilities Board. 2007. *Bulletin 2007-05: 2006 Alberta Coalbed Methane Activity Summary and Well Locations,* http://www.eub.ca/docs/documents/bulletins/bulletin-2007-05.pdf

[157] Howard, Peter; Govinda Timilsina, Janna Poliakov, Michael Gatens, Peter Bastian, Chris Mundy. 2006. *Socio-Economic Impact of Horseshoe Canyon Coalbed Methane Development in Alberta,* p.1 and 12. Canadian Energy Research Institute and Canadian Society for Unconventional Gas. The total resource in the area described is estimated to be 30.3 tcf. The total CBM that is recoverable from the Horseshoe Canyon Formation is estimated at about 10 to 12 tcf from approximately 35,000 wells.

[158] A company is required to apply to the EUB to obtain approval for a well density that is higher than the standard.

from the deep Mannville Formation, it may locate 8 to 16 wells on one pad and access the gas under two to four sections, using horizontal wells deep underground.

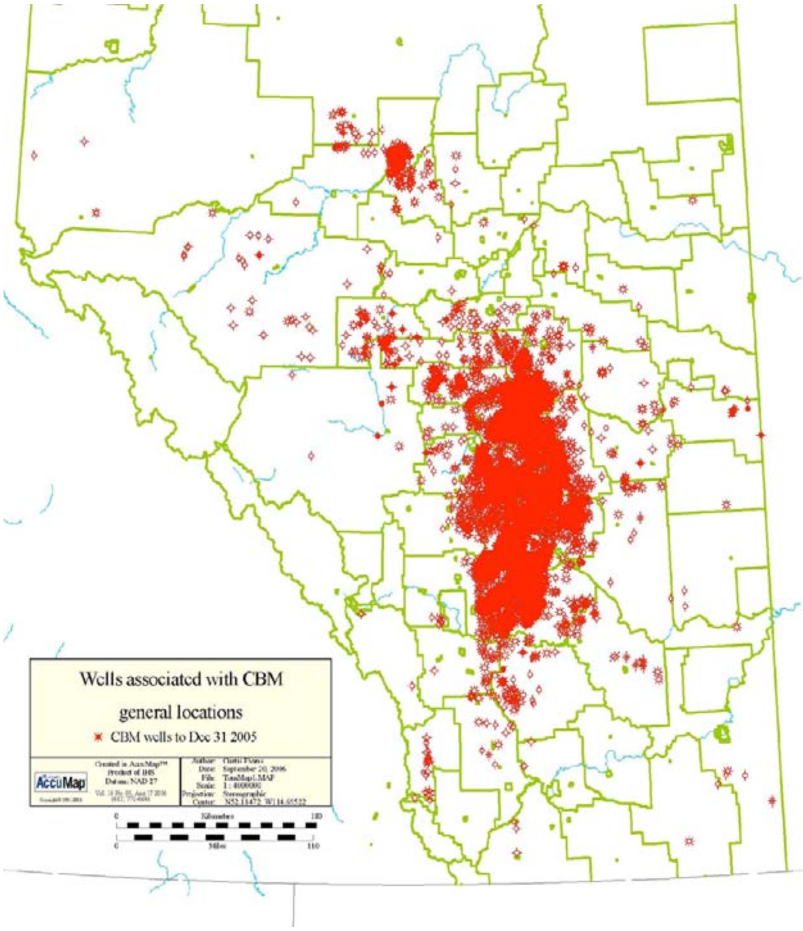

Figure 3-4 Coalbed methane wells in Alberta, December 31, 2005

Source: Alberta Energy and Utilities Board

3.2.2 How can coalbed methane development affect water?

The potential for CBM production to affect fresh water will primarily be determined by the depth of the coal seams and whether they contain fresh or saline water or are dry. When the coal seams contain water, it is first necessary to produce some of the water to reduce the pressure in the coal and allow the gas to flow to the wellbore. The potential impacts of removing this water will depend on the depth of the coal seams and the salinity of the water. These factors may also affect how the water is handled.[159]

Figure 3-5 shows the generalized relationship between coal-bearing formations in central Alberta, the base of groundwater protection and water wells. Although the majority of producing

[159] Petroleum Technology Alliance Canada. 2006. *Filling the Gap: Unconventional Gas Technology Roadmap,* p. 36-38, *http://www.ptac.org/cbm/dl/PTAC.UGTR.pdf*

coal seams are deeper than 200 metres, the shallowest CBM wells have been drilled at a depth of about 50 metres,[160] which is shallower than many water wells.

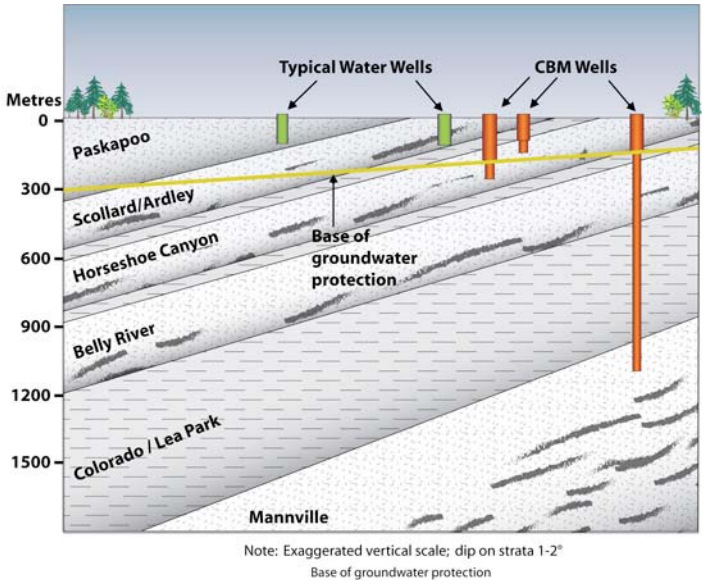

Figure 3-5 Coalbed methane wells and the base of groundwater protection

Source: The Pembina Institute, adapted from Alberta Energy and Utilities Board and Alberta Environment figures

As noted earlier, although some coals in the Horseshoe Canyon contain water (especially towards the northern and eastern edge of the formation, such as the Ferintosh area south-east of Wetaskiwin) they are predominantly dry, so the CBM will flow to the wellbore as soon as a well is drilled. It is uncertain why a majority of the coal seams in the Horseshoe Canyon Formation are dry, but the formation is overlain by low permeability units that restrict water from overlying aquifers flowing into the coal seams. Extracting methane from these low pressure (under-pressured) dry coals is not expected to affect any aquifers. However, even dry coals produce a very small amount of water with the gas.[161] The water usually collects in a sump at the bottom of the wellbore and is pumped out intermittently and sent for deep well disposal.

The Ardley Coal Zone (within the Scollard Formation — see Figure 3-3) may contain fresh or saline water, however the Ardley Coal Zone has recently been determined to be relatively dry in some areas, especially the lower parts of the zone.[162] There are concerns that production from shallower formations in the Ardley could impact groundwater resources; even where the Ardley is deeper there are concerns about potential effects on overlying shallow groundwater systems (see section 2.3.2).

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[160] Canadian Society for Unconventional Gas. 2006. Untitled document giving responses to questions asked at Alberta Environment public information sessions on CBM, http://www.waterforlife.gov.ab.ca/coal/docs/Canadian_Society_for_Unconventional_Gas.pdf See also http://www.waterforlife.gov.ab.ca/coal/index.html

[161] The average volume produced from wells in the Horseshoe Canyon Formation depends on the location. One company analyzed over 1100 wells with sufficient production history and found that the mean water production is 0.3 m^3/month, with a minimum of zero and a maximum of 4 m^3/month, but 90% of the wells produced less than about 0.9 m^3/month. Doreen Rempel, Quicksilver Resources Canada, personal communication with Mary Griffiths, January 21, 2007. A more global look at data on water production from the Horseshoe Canyon shows average water production of 2.3 m^3/month. This average includes a number of "wet" Horseshoe Canyon CBM wells, particularly on the northeastern fringe of the area of CBM production. Over 57% of the wells reported no water production at all and over 76% of the wells have produced less than 5 m^3 of water over their entire production history. Burns Cheadle, Outrider Energy Ltd., personal communication with Mary Griffiths, January 7, 2007.

[162] Richards Oil and Gas. 2006. *Our Assets: Core Properties: Ardley Resource Play*, http://www.richardsoilandgas.com/our_assets/ardley.html Some dry Ardley coals have been found in the Hinton area.

The deep Mannville Formation contains considerable volumes of saline water, so it may be necessary to pump out water for weeks or months before pressure in the seams is reduced sufficiently to produce commercial quantities of gas.

In the Foothills, water in the Kootenay Formation may be fresh or saline, depending on the depth. At the time of writing, the only pilot project in the Kootenay had ceased, as it produced too much water and too little gas.

The actual process of CBM production may affect water in a number of ways. Some potential impacts, such as the effect of drilling fluids or the production of non-saline water, are also relevant to the production of shallow gas, but they have gained attention with the rapid development of CBM. In particular, landowners are concerned that fracturing of coal seams could impact fresh water aquifers. Effects are likely to be greatest where the coals are relatively shallow, such as the Ardley Coal Zone, but some landowners have complained of water well problems, including gas in water wells, in areas where CBM is being produced from the Horseshoe Canyon Formation. These complaints are being investigated (see section 4.5).

The MAC was aware of public concerns and one-third of the recommendations in its final report relate to water.[163] Some recommendations are summarized here, with those that the committee considered most important at the top of the list. The recommendation number in the report is given in brackets. The committee recognized the need to do the following:

- Protect aquifers by developing a decision-tree approach to review CBM applications for non-saline water production. The process takes into account the level of risk to aquifers. (#3.3.2)
- Improve scientific information about aquifers. This requires, for example, an expansion of the Alberta Environment monitoring network and data management system, a complete inventory of groundwater in the province and completion of the mapping of the base of groundwater protection. (#3.2.1)
- Investigate the potential for methane migration or release to water wells. (# 3.6.1)
- Develop standard procedures for testing and reporting on the quality and quantity of non-saline and saline water and potentially impacted non-saline water wells. (#3.3.5)
- Investigate drilling fluids. This includes researching whether drilling and completion practices, such as the use of water from farm dugouts and untreated river water may affect aquifers. Also a review is recommended of substances used in drilling and completion fluids. (#3.4.2)
- Enhance Alberta Environment's *Guidelines for Groundwater Diversion for Coalbed Methane/Natural Gas in Coal Development* and conduct a province-wide review of existing CBM wells to ensure all guidelines have been met. (#3.3.3)
- Protect aquifers by clarifying Alberta Environment's rules, which limit the extent to which water levels can be drawn down during depressurization in a confined non-saline aquifer. (#3.3.4)

[163] Government of Alberta. 2006. *Coalbed Methane/Natural Gas Multi-Stakeholder Advisory Committee Final Report,* http://www.energy.gov.ab.ca/docs/naturalgas/pdfs/cbm/THE_FINAL_REPORT.pdf

- Develop a water well testing program to establish a baseline before a CBM well is drilled and establish a clear process to address water well complaints. (#3.3.6)
- Review drilling and completion practices, including fracturing. (#3.3.7)
- Review the existing requirements for deep well disposal of non-saline produced water to ensure they promote the wise use and conservation of water. (#3.5.1)
- Establish criteria for the beneficial use of marginally saline produced water. (#3.5.2)

Many of these impacts are examined in Chapter 4. The government is implementing all the MAC's recommendations with respect to water and the committee is monitoring progress.

Handling of saline water was not considered by the committee, as it is not unique to CBM development. Within this report it is discussed in section 4.4.

3.2.3 What are the government regulatory programs for coalbed methane?

The EUB initially regulated CBM in the same way as conventional natural gas (and only required CBM wells to be identified by a separate code in the fall of 2003). The regulation of CBM is still basically the same as for conventional gas, but Alberta Environment has introduced some requirements for protecting non-saline (fresh) groundwater. As the MAC's recommendations are implemented, additional changes may be made in the way in which CBM development is managed to protect fresh groundwater.[164]

If a company expects to complete a CBM well in a coal seam containing fresh water it must meet both EUB and Alberta Environment requirements.[165] These requirements are described in the next two subsections.

3.2.3.1. Baseline water well testing for shallow CBM wells

Due to concerns that gas production from shallow coal seams may impact fresh aquifers, Alberta Environment introduced a Standard for Baseline Water Well Testing.[166] It requires a company to test water wells within 600 metres of any well that is drilled (or recompleted) for the production of CBM if the CBM well will be producing above the base of groundwater protection. If there is no water well within 600 metres of the proposed CBM well, the company must test the nearest water well within a 600- to 800-metre radius.[167] In addition "AENV [Alberta Environment] and the EUB expect industry to identify those situations where unique geological or topographical conditions, or landowner concern warrant testing at greater distances or more than one well in

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[164] Government of Alberta. 2006. *Coalbed Methane/Natural Gas Multi-Stakeholder Advisory Committee Final Report,* http://www.energy.gov.ab.ca/docs/naturalgas/pdfs/cbm/THE_FINAL_REPORT.pdf When the report was released the Minister of Energy announced that the government intended to accept 42 of the 44 recommendations (the exceptions relate to royalties). The MAC is monitoring implementation of the recommendations and will release a progress report. More information will be available on the Alberta Energy web site at http://www.energy.gov.ab.ca/245.asp

[165] Alberta Energy and Utilities Board. 2004. *EnerFAQs 10: Coalbed Methane,* http://www.eub.ca/portal/server.pt/gateway/PTARGS_0_0_281_237_0_43/http%3B/extContent/publishedcontent/publish/eub_home/public_zone/eub_process/enerfaqs/

[166] Alberta Environment. 2006. *Standard for Baseline Water-Well Testing for Coalbed Methane/Natural Gas in Coal Operations,* http://www.waterforlife.gov.ab.ca/coal/docs/CBM_Standard.pdf Baseline testing was recommended by the MAC, see recommendation #3.3.6.

[167] Some members of the government's Coalbed Methane/Natural Gas in Coal Multi-Stakeholder Advisory Committee suggested that wells within 880 metres (i.e., ½ mile) should be tested prior to coalbed methane development, but the Committee could not reach consensus on this point. Government of Alberta. 2006. *Coalbed Methane/Natural Gas in Coal Multi-Stakeholder Advisory Committee Final Report,* p. 25, http://www.energy.gov.ab.ca/docs/naturalgas/pdfs/cbm/THE_FINAL_REPORT.pdf

the 600–800 metre radius."[168] This requirement assumes that an accurate regional understanding of the groundwater flow regime exists, which may not be a valid assumption.

Testing must be conducted in the way set out in the standard and includes a two-hour yield test, the collection of water quality samples and a test for the presence of gas. The water samples must be tested for routine potability (which includes tests for the presence of various minerals such as calcium, chloride, iron, nitrite and nitrate and total dissolved solids) and bacteria (including iron and sulphate-reducing bacteria and total and fecal coliform) commonly found in water. If there is any free gas in the water, gas samples must be collected and sent to a laboratory accredited to do compositional analysis.

If free gas is found, gas and water samples must be collected from a representative number of wells. The volume of gas per flow-through volume of water must be recorded and the stable isotopic composition of the gas analyzed.[169] The way in which the gas sample must be collected and analyzed is set out in a protocol: "A minimum of 20% of free gas samples collected from water wells around each CBM well must undergo isotopic analysis, up to a maximum of 10 samples per CBM well. At least one gas sample must be submitted for isotopic analysis per CBM well."[170]

The standard does not require the analysis of dissolved gas,[171] but Alberta Environment is undertaking research on the value of sampling it and whether it can be done accurately.

A landowner can refuse a water well test and Alberta Environment routinely investigates water well complaints where there is no baseline data. However, baseline information makes complaint investigation easier, particularly if there are later changes in water well production or water quality.

If a landowner does not want his or her water well tested, the company must obtain written confirmation from the landowner that testing is not required. If a landowner declines to provide written confirmation of his or her refusal, a company representative must record this, and give the landowner a notice describing this protocol. It is important for landowners to be aware of the required process and to immediately notify the EUB if the company fails to comply with the requirements.[172]

Alberta Environment's standard requires a company to return the results of the water well tests within two months, or to give a reason why it is taking longer.[173] Landowners may try to negotiate for the return of the water testing results prior to allowing drilling to commence since

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[168] Alberta Environment. 2006. *Standard for Baseline Water-Well Testing for Coalbed Methane/Natural Gas in Coal Operations,* http://www.waterforlife.gov.ab.ca/coal/docs/CBM_Standard.*pdf*

[169] Alberta Environment. 2006. *Gas Sampling Requirements for Baseline Water-Well Testing for Coalbed Methane/Natural Gas in Coal, http://www.waterforlife.gov.ab.ca/coal/docs/Gas_sampling_for_CBM.pdf*

[170] Alberta Environment. 2006. *Gas Sampling Requirements for Baseline Water-Well Testing for Coalbed Methane/Natural Gas in Coal Operations, http://www.waterforlife.gov.ab.ca/coal/docs/Gas_sampling_for_CBM.pdf* Alberta Environment does not require isotopic testing of all water samples, as the characteristics of the gas will normally be consistent within the distance being tested around a CBM well. Isotopic testing is very expensive and costs approximately $400 for the laboratory isotope analysis of a sample. In addition there are the costs of collecting the sample and analysing the proportion of different gases in the sample.

[171] It is most important to identify the composition of the gas to help determine its source. The gas composition will be the same, whether it is free or dissolved, so measurement of dissolved gas will not help in the identification of the source.

[172] Landowners have reported that a company used "implied refusal", if a landowner failed to contact them asking for their water well to be tested. In such situations, the company cannot even be sure that the landowner has received the information package about baseline water well testing.

[173] The results are also reported to Alberta Environment and are entered into a database that will become public.

some landowners have complained that the baseline data has been lost in the process.[174] Once a well has been drilled or fractured, it is too late to get the pre-drilling baseline data.

Alberta Environment's baseline water well testing requirements are implemented and enforced by the EUB.[175] The EUB has an audit process to check selected company well-drilling applications and ascertain that the company has correctly informed landowners about the opportunity for a baseline water well study.[176]

Although Alberta Environment's standard refers to the collection of baseline data, its "baseline" refers to the conditions that exist in 2006 or later. It is not the pre-development baseline, but rather includes decades of oil and gas activity in the province that may have caused some changes in aquifers.[177] However, since baseline testing was introduced, it does provide a record of conditions before the latest CBM developments.

If a landowner finds a change in water well quality or quantity after CBM development he/she must inform Alberta Environment of the complaint and the CBM developer must retest the water well. It is important to ensure that Alberta Environment is informed before the water well is retested.[178] Alberta Environment staff investigates complaints and coordinates with the EUB and the regional health authority, where appropriate.[179]

Alberta Environment planned to review the standard after six months and to conduct a comprehensive review after a year, which will form the basis of a report. The review will determine whether the standard needs to be modified. A scientific panel has been established by Alberta Environment to conduct the review.[180]

Additional information on issues that may arise with respect to water well testing, including gas migration, dissolved gas, bacteria and isotopic testing, is given in Chapter 4 and Appendix A.

Some landowners feel that the baseline water well testing is not stringent enough and want it to include a test for dissolved gas (see comments on dissolved gas test in section 4.5).[181] A landowner can always try to negotiate for additional testing with any company requesting access to his or her lands.

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[174] Norma LaFonte, personal communication with Mary Griffiths, January 21, 2007.

[175] Alberta Energy and Utilities Board. 2006. *Directive 035. Baseline Water Well Testing Requirement for Coalbed Methane Wells Completed Above the Base of Groundwater Protection,* http://www.eub.ca/docs/documents/directives/directive035.pdf The fact that the EUB implements the Alberta Environment requirement may be partly in response to the Canadian Association of Petroleum Producers position that: "The government of Alberta should adopt a 'one-window' approach pursuant to which all licenses required to operate an NGC development would be obtained from the EUB, accounting for the concerns of all ministries that currently have jurisdiction over the matter." Canadian Association of Petroleum Producers. 2003. *Natural Gas from Coal in Alberta: Position Paper prepared for the Canadian Association of Petroleum Producers,* p. 11, http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=72435

[176] Alberta Energy and Utilities Board. 2006. *Directive 035. Baseline Water Well Testing Requirement for Coalbed Methane Wells Completed Above the Base of Groundwater Protection,* section 2.1.1, http://www.eub.ca/docs/documents/directives/directive035.pdf

[177] It had been suggested that open seismic holes, stratigraphic test holes and poorly cemented or uncemented oil and gas wells (prior to remediation) may have allowed changes, but it would be very difficult or impossible to prove this.

[178] Complaints should be registered with Alberta Environment by calling 1-800-222-6514. This is the 24-hour environmental hotline.

[179] Alberta Environment. Undated. *Water Well Investigations,* http://www.waterforlife.gov.ab.ca/coal/docs/Water_Well_Investigations.pdf

[180] Alberta Environment. 2006. *Standard for Baseline Water-Well Testing for Coalbed Methane/Natural Gas in Coal Operations,* http://www.waterforlife.gov.ab.ca/coal/docs/CBM_Standard.pdf

[181] Norma LaFonte, personal communication with Mary Griffiths, January 21, 2007.

3.2.3.2. Diversion of water from shallow CBM wells

As explained above, if a company wishes to produce CBM from a coal seam that contains water it must first remove the water to reduce the pressure on the formation. If the water is fresh, removal of the water could have an adverse impact on shallow aquifers. If a company plans to drill a CBM well into a formation that may contain non-saline water, it must comply with Alberta Environment's requirements. At the time of writing, these requirements are being revised to correspond with the MAC recommendations.

As noted in section 3.1.3.1, EUB *Directive 44*, requires all companies to report the volume of water produced if any type of gas well is completed or has perforations above the base of groundwater protection. The board must be immediately notified if the volume of produced water exceeds 5 m^3/month. The EUB will review the situation with the company and determine what measures are being taken to protect non-saline groundwater. If there is no risk of commingling of water from different formations, a company may be allowed to produce some water from a shallow CBM well, provided it meets the requirements of Alberta Environment's proposed Code of Practice (as noted in section 3.1.3.1). It is intended that this code will apply if a well produces more than 5 m^3/month but less than 30 m^3/month of water and the total volume diverted from a section of land (640 acres) is less than 100 m^3/month.[182] These are interim threshold values, as proposed by the MAC and may be modified as a result of research and experience.

If, based on other CBM wells in an area, a company expects to produce a large volume of non-saline water, it must submit an application to Alberta Environment to divert the water before starting to drill.[183] Alternatively, if, on drilling a CBM well, a company finds that a well that was expected to operate under the Code of Practice produces more than the upper threshold limit, it must immediately notify the EUB and Alberta Environment. Alberta Environment will work with the EUB and the company to resolve the situation. In some cases the company may shut in the well or shut off the perforations to the zone producing non-saline water, but if the company wishes to keep operating it will have to apply for a diversion permit.[184] The application must be accompanied by a detailed technical report that includes an overview of the existing geological and hydrologic information, the results of an aquifer test and an analysis of the water quality, including a sample of the base composition and the stable isotopes of each gas detected (methane, ethane, propane, and so on). The technical report must also include an assessment of the cumulative impact of diverting the non-saline groundwater for the entire project. Once the application is made, the company is required to notify the public by placing an advertisement in a newspaper that circulates in the area. Members of the public who are directly affected may submit a Statement of Concern that Alberta Environment must consider before deciding whether

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[182] This would allow up to 1,200 m^3/year per section to be diverted without prior approval. For comparison, the *Water Act*, sections 1(1)(x) and 21, allows a landowner or occupier to withdraw up to 1,250 m^3/year for "household purposes" (i.e., for human consumption, watering animals, gardens and lawns, etc.), *http://www.qp.gov.ab.ca/documents/Acts/W03.cfm?frm_isbn=0779727428*

[183] Alberta Environment. 2004. *Guidelines for Groundwater Diversion for Coalbed Methane/Natural Gas in Coal Development,* *http://www3.gov.ab.ca/env/water/Legislation/Guidelines/groundwaterdiversionguidelines-methgasnatgasincoal.pdf* At the time of writing, these Guidelines are being revised.

[184] Alberta Environment. 2004. *Guidelines for Groundwater Diversion for Coalbed Methane/Natural Gas in Coal Development,* *http://www3.gov.ab.ca/env/water/Legislation/Guidelines/groundwaterdiversionguidelines-methgasnatgasincoal.pdf* 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.

to permit (or continue to permit) diversion of the water.[185] Anyone directly affected who has submitted a Statement of Concern is also entitled to appeal the department's decision.[186]

Alberta Environment intends to develop a policy to encourage the beneficial use of produced water. Depending on the salinity, the water may first need to be treated. Before any water is discharged to surface waters or used for agricultural purposes (irrigation and livestock) it is essential to require regular water quality monitoring to ensure the water meets the criteria for the specified use.[187] Some dissolved solids are more harmful than others and of particular importance is the relative proportion of sodium ions to the concentration of calcium and magnesium. This relationship is described as the Sodium Adsorption Ratio (SAR). A high SAR may affect soil structure, limit permeability and be toxic to plants.[188] The salinity levels that are suitable for irrigation vary with the soil and crop, as some species are more salt-tolerant than others.[189]

As indicated earlier in section 3.1.3.1, the EUB regulates the disposal of produced water and at the time of writing even non-saline water is usually sent for deep well disposal. However, the EUB expects that wherever possible companies will conserve water resources, including surface waters and waste streams, and *Directive 51* allows scope for produced water to be treated and used.[190]

3.2.3.3. Deep CBM wells

Deep CBM wells can be defined as those that produce saline water, which may be collected in tanks and trucked out or piped to a disposal well, in the same way as for conventional gas or oil wells.[191] If saline water is stored on site, precautions must be taken to ensure that any spill is contained and does not contaminate surrounding land.[192] Pad drilling of horizontal wells offers the best opportunity to manage produced water handling and contain any spills. It is possible that the produced saline water could be used for injection to enhance oil recovery, as Alberta

[185] Alberta Environment. 2004. *Groundwater Diversion for Coalbed Methane/Natural Gas in Coal Development,* http://www3.gov.ab.ca/env/water/Legislation/Guidelines/groundwaterdiversionguidelines-methgasnatgasincoal.pdf

[185] Government of Alberta. *Water Act*, s.109 (1)(a), http://www.qp.gov.ab.ca/documents/Acts/W03.cfm?frm_isbn=0779727428

[186] Government of Alberta. *Water Act*, s.115(1)(c), http://www.qp.gov.ab.ca/documents/Acts/W03.cfm?frm_isbn=0779727428

[187] At present deep well injection of water is the normal process to ensure that no problems are caused by the discharge of water containing harmful levels of salts. If a company wishes to discharge or use produced water they must make a special application to the EUB and Alberta Environment. N.B. Alberta Environment's *Surface Water Quality Guidelines for Use in Alberta,* apply to site runoff, rather than produced water http://environment.gov.ab.ca/info/library/5713.pdf The Guidelines may also be used in setting water quality based approval limits for wastewater discharges (p. 2).

[188] Agriculture and Agri-Food Canada. 1999. *Water Quality Fact Sheet: Irrigation and Salinity*, http://www.agr.gc.ca/pfra/water/irrsalin_e.htm TDS levels below 700 mg/l and SAR below 4 are considered safe; TDS levels between 700 and 1,750 mg/l and SAR levels between 4 and 9 are considered possibly safe, while levels above these are considered hazardous to any crop.

[189] Alberta Agriculture, Food and Rural Development. 2003. *Salinity and Sodicity Guidelines for Irrigation Water,* http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/irr6428

[190] Alberta Energy and Utilities Board.1994. *Directive 051: Injection and Disposal Wells – Well Classification, Completions, Logging and Testing Requirements,* Section 2.2, Deepwell Philosophy, p. 4, http://www.eub.ca/docs/documents/directives/Directive051.pdf

[191] Alberta Energy and Utilities Board.1994. *Directive 051: Injection and Disposal Wells – Well Classification, Completions, Logging and Testing Requirements,* http://www.eub.ca/docs/documents/directives/Directive051.pdf

[192] Alberta Energy and Utilities Board. 2005. *Directive 056: Energy Development Application and Schedules (September 2005),* Section 7.9.12.1, p. 181, http://www.eub.ca/docs/documents/directives/directive056.pdf See also Alberta Energy and Utilities Board. 2001. *Directive 055: Storage Requirements for the Upstream Petroleum Industry*, http://www.eub.ca/docs/documents/directives/Directive055.pdf

Environment is encouraging companies to look for alternatives to fresh water for enhanced oil recovery.[193]

3.3 Shale gas

3.3.1 What is shale gas?

Shale is a fine-grained rock formed by the deposition and compression of clay, silt and sand, although the rock is dominated by clay-sized minerals. Shale may contain organic matter and be a source of hydrocarbons. The gas is stored in the rock in three main ways:

- Adsorbed or bonded onto the surface of insoluble organic matter in the rock
- Trapped in pore spaces in the rock
- Confined in fractures within the shale.[194]

Shale gas is either formed by bacteria (biogenic gas) or by the effect of heat and pressure on organic matter deep under the surface (thermogenic gas).[195] Some of the gas is stored in the pore space and is called "free gas" (as in conventional gas reserves) and some is adsorbed onto the organic matter (kerogen) in the shale (similar to CBM). Industry uses the type of kerogen found in shale as well as the total organic content to classify the shale. The proportion of gas that is adsorbed varies considerably,[196] as does the total gas content of shale.

Beds of gas shale are usually much thicker than coal seams. Although they contain a large volume of gas in place, the recovery rate is generally much lower than from coal seams or from conventional gas formations. Shale usually extends over very wide areas and hence shale gas reservoirs are termed "continuous."[197] The suitability of reservoirs for development depends on the permeability and porosity of the rocks. Even when shale has sufficient porosity with natural fractures providing some permeability, the wells need to be stimulated by fracturing techniques, so the gas can flow to the wellbore in commercial quantities. Developing and implementing the technologies to unlock the resource is an important aspect of shale gas production. The decision to develop a specific shale zone will depend on characteristics such as the maturity of organic matter, shale thickness and the extent of natural fractures. Successful projects are usually located where shale is brittle because brittle shale is more easily fractured than is soft shale.

In the U.S. several regions are producing shale gas and in 2005 there were approximately 30,000 shale gas wells,[198] producing between 3 and 4% of domestic gas production.[199] The rates of

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[193] Alberta Environment. 2006. *Water Conservation and Allocation Policy for Oilfield Injection,* http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_Policy.pdf and *Water Conservation and Allocation Guideline for Oilfield Injection, http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_GUIDELINE.pdf*

[194] Centre for Energy. 2007. *Natural Gas: Shale Gas Overview, http://www.centreforenergy.com/silos/ong/ET-ONG.asp*

[195] Canadian Society for Unconventional Gas. *Shale Gas Overview. http://www.csug.ca/faqs.html#Sa*

[196] In the U.S. the adsorbed gas varies between 20% and 60% in the Barnett Shale (Terratek Inc. brochure, undated, *Shales and Unconventional Reservoirs*), while up to 85% of the gas may be adsorbed in the Lewis shale. See Ball, Candice. 2005. "Shale Silence is Deafening", *Unconventional Gas Supplement – Oilweek* , p.23, August.

[197] A "continuous" accumulation of gas is one that is regional in extent and it not controlled by buoyancy. For a detailed definition see Christopher J. Schenk. 2002. *Geologic Definition and Resource Assessment of Continuous (Unconventional) Gas Accumulations – the U.S. Experience, http://www.searchanddiscovery.net/documents/abstracts/cairo2002/images/schenk.htm*

[198] Dawson, Mike. 2005. *Unconventional Gas in Canada: An Important New Resource.* For CSUG at B.C. Oil and Gas Conference. Ft. St. John, October 5, slide 18, *http://www.csug.ca/pres/CSUG%20051005%20BC%20O&G%20Conference.pdf* Production in 2005 was approximately 1.6 bcf/d.

production along with the techniques to drill and complete wells vary considerably from one shale area to another. Production from shale started many years ago, but new areas, such as the Barnett shale in Texas, are experiencing rapid growth.[200]

The development of shale gas is relatively new in Canada and as rates of sustained production are fairly low (generally less than 100–200 mcf/d[201]), development is sensitive to the price of natural gas. Shale accounts for almost two-thirds of the rock in the Western Canada Sedimentary Basin, and deposits extend from southern Manitoba and Saskatchewan, through Alberta into northeast British Columbia. It has been estimated that the total resource in place in the basin could be as much as 10,000 tcf or more,[202] but the organic-rich shale formations in Alberta and British Columbia that contain sufficient gas to make recovery economic are much more limited in extent.[203] The Gas Technology Institute evaluated only part of the shale gas resource and found that "formations studied in the basin contain potentially large volumes of hydrocarbons, because these organic rich rocks have the potential to generate and store large volumes of methane regardless of their maturity, or generally how deep they are."[204] This institute estimated that the shale gas potential in the formations it studied could be 86 tcf.[205] As indicated in Chapter 1, the National Energy Board estimates the shale gas resource in the Western Canada Sedimentary Basin to be 250 tcf,[206] although another source puts the basin's shale gas potential at more than 860 tcf.[207] Geologists are learning about the characteristics of different types and ages of shale in Alberta[208] and have estimated the volume of gas in place in some specific shale formations in Alberta.[209] Further research is under way and more work is needed to evaluate the recoverable reserves of shale gas. In 2005 the Alberta Research Council's unconventional gas

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[199] Faraj, Basim. 2006. *An Overview of Shale Gas Activity in Canada and the U.S.*, The Canadian Institute's 2nd Annual Capturing Opportunities in Canadian Shale Gas Conference, January 31 and February 1, Calgary.

[200] In the successful Barnett shales in Texas, the organic content is 4.5 %. Gary Schein. *Barnett Shale Completions*, slide 8. The Canadian Institute's 2nd Annual Capturing Opportunities in Canadian Shale Gas Conference, January 31 and February 1, Calgary.

[201] For comparison, in the mid 1990s the average conventional gas well produced about 600 mcf/d at the start of production, but the average for all gas wells declined to about 200 mcf/d by 2005.

[202] Basim Faraj, Talisman Energy, personal communication with Mary Griffiths, September 19, 2006.

[203] Faraj, Basim. 2006. *An Overview of Shale Gas Activity in Canada and the U.S.*, slide 13, The Canadian Institute's 2nd Annual Capturing Opportunities in Canadian Shale Gas Conference, January 31 and February 1, Calgary.

[204] Jaremko, Deborah. 2005. "Sleeping Giant: Canadian Shale Gas Potential Huge But Waits For Assessment of Technology," p. 43, *Oilweek*, May. The Gas Technology Institute suggested that the resource potential of shale gas of a few formations they studied in a limited area of northwestern Alberta and British Columbia could exceed 86 tcf. Canadian Society for Unconventional Gas. Shale Gas Overview, http://www.csug.ca/faqs.html#Sa

[205] Faraj, Basim, Harold Williams, Gary Addison, Brian McKinstry, et al., 2004. "Gas Potential of Selected Shale Formations in the Western Canadian Sedimentary Basin, *GasTIPS*, Winter, p. 21 – 25, http://www.gastechnology.org/webroot/downloads/en/4ReportsPubs/4_7GasTips/Winter04/GasPotentialOfSeclectedShaleFormationsInTheWesternCanadianSedimentaryBasin.pdf Starting with the most recent, these formations are: Upper Cretaceous Shale, the Poker Chip/Nordegg (Jurassic), Montney/Doig (Triassic) Besa River/Exshaw and Duvernay/Cynthia (Upper Devonian) and Keg River (Middle Devonian). Some wells have been completed in the Second White Specks shale and Poker Chip shale.

[206] National Energy Board. 2006. *British Columbia's Ultimate Potential for Conventional Natural Gas*, p.23, http://www.neb.gc.ca/energy/energyreports/emanebcgasultimatepotential2006/emanbcgasultimatepotential2006_e.pdf

[207] This estimate by the Gas Technology Institute is cited in *Unconventional Gas, Supplement to Oilweek*, August 2006, p.8. See also Canadian Gas Potential Committee. 2006. Natural Gas Potential in Canada – 2005, Brochure, p. 4, http://www.canadiangaspotential.com/2005report/brochure_4page.pdf

See also, AJM Consultants – 100 tcf Resource, http://www.ajma.net/about/pdfs/ajm_pres_2005_09_reserves.pdf

[208] Ross, Daniel and Marc Bustin. 2006. *Re-evaluation of Gas Shale Reservoir Characterization: Applicability of CBM Analogues*, Canadian Society of Petroleum Geologists, Canadian Society of Exploration Geophysicists and Canadian Well Logging Society, Joint Conference, Calgary, May 15-18, 2006, http://www.cspg.org/conventions/abstracts/2006abstracts/100S0130.pdf

[209] Centre for Energy, 2007. *Shale Gas Overview, Where is Shale Gas Found?* http://www.centreforenergy.com/silos/ong/ET-ONG.asp

group spent 75% of its budget investigating shale gas.[210] The Alberta Geological Survey is evaluating shale gas resources and intends to create geological and geochemical maps showing areas of shale gas potential.[211] A detailed overview of the potential shale formations in Alberta is provided in a report from the Geological Survey of Canada.[212]

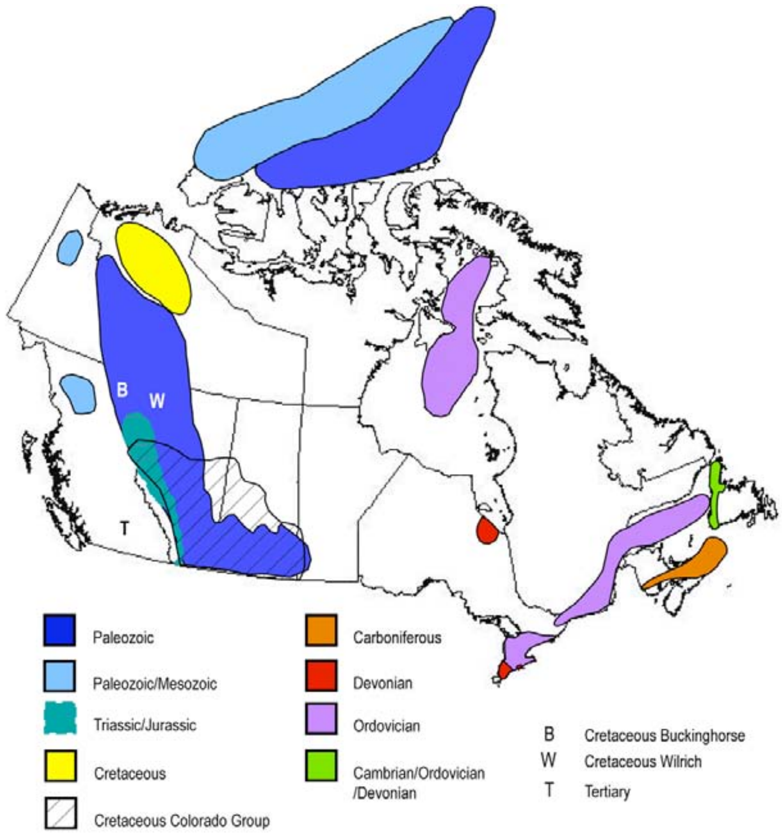

Figure 3-6 The extent of shale gas formations in Canada
Source: Alberta Geological Survey and Geological Survey of Canada[213]

By the beginning of 2006 about 30 companies were active in shale gas exploration,[214] and it has been suggested that shale gas development in Alberta is at the same stage as CBM was about five years ago. As the EUB does not have a separate code for shale gas, it is not easy to identify the location of shale gas wells. Companies may also elect to commingle the production of shale gas with production from conventional gas wells or CBM, where the gas pressures make this possible.

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[210] Jaremko, Deborah. 2005. "Sleeping Giant: Canadian Shale Gas Potential Huge But Waits For Assessment of Technology," p. 41, *Oilweek*, May. One initiative involves work to develop ways to accurately determine the gas potential of shale from drill cuttings.

[211] Rauschning, Sharla. 2006. *Alberta's Shale Gas Regulatory Structure*, slide 6. The Canadian Institute's 2nd Annual Capturing Opportunities in Canadian Shale Gas Conference, January 31 and February 1, Calgary.

[212] Hamblin, Anthony P. 2006. *The "Shale Gas" Concept in Canada: A Preliminary Inventory of Possibilities*, Geological Survey of Canada, Open File 5384, http://geopub.nrcan.gc.ca/ Use GEOSCAN and insert 5384 to locate the publication. This publication includes maps showing the general extent of the main shale zones.

[213] Map provided by Dean Rokosh, Alberta Geological Survey and Anthony Hamblin, Geological Survey of Canada.

[214] Faraj, Basim. 2006. *An Overview of Shale Gas Activity in Canada and the U.S.*, slide 36, The Canadian Institute's 2nd Annual Capturing Opportunities in Canadian Shale Gas Conference, January 31 and February 1, Calgary.

3.3.2 How can shale gas development affect water?

Extraction of shale gas may require a high density of wells, where economically warranted, to maximize production; each well will require fracturing to increase the size of the pathways for gas to flow to the wellbore. Some water will be needed for drilling the wells and water may be required for fracturing, although fracturing may also be carried out using nitrogen,[215] carbon dioxide or other substances.[216] General details about drilling, fracturing and the disposal of water are given in Chapter 4. Here, we give a few examples of selected characteristics of shale gas in parts of the U.S. The main lesson from the U.S. experience is that the geological and geochemical characteristics of shale are diverse, so the impacts of shale gas extraction vary significantly from one area to another. At present, it is not possible to say which areas will be relevant for development in Alberta.

Experience in the U.S. shows that many shale formations are almost dry like the long-producing Ohio shales of Appalachia, but occasionally they produce large volumes of relatively fresh water, as shown in Figure 3-7. This water must be drained off to reduce pressure in the formation before the gas can be produced, in a manner similar to CBM.[217] The Antrim shale in Michigan produces moderate volumes of water (from 3 to 16 m^3/day), while the New Albany shale in the Illinois Basin may produce from 1 to 80 m^3/day. The Antrim and New Albany shales contain biogenic gas, which, in the case of the Antrim shale, is believed to have been generated during the past 22,000 years by bacteria circulating in groundwater.[218] Conditions in parts of the Colorado Formation in Alberta may be similar to those in the Antrim and Lewis shales in the U.S.[219]

[215] Gardes, Bob. 2006. *Canadian Shale Gas: A Technology Drive Resource in its Infancy,* The Canadian Institute's 2nd Annual Capturing Opportunities in Canadian Shale Gas Conference, January 31 and February 1, Calgary.

[216] Centre for Energy. 2007. *Shale Gas Overview: How is Shale Gas Produced?* http://www.centreforenergy.com/silos/ong/ET-ONG.asp

[217] Centre for Energy. 2007. *Shale Gas Overview: How is Shale Gas Produced?* http://www.centreforenergy.com/silos/ong/ET-ONG.asp

[218] Faraj, Basim, Harold Williams, Gary Addison, Brian McKinstry, et al., 2004. "Gas Potential of Selected Shale Formations in the Western Canadian Sedimentary Basin", *GasTIPS,* Winter, p. 21–25.

[219] Hamblin, Anthony P. 2006. *The "Shale Gas" Concept in Canada: A Preliminary Inventory of Possibilities,* p. 54. Geological Survey of Canada, Open File 5384, http://geopub.nrcan.gc.ca/ Use GEOSCAN and insert 5384 to locate the publication.

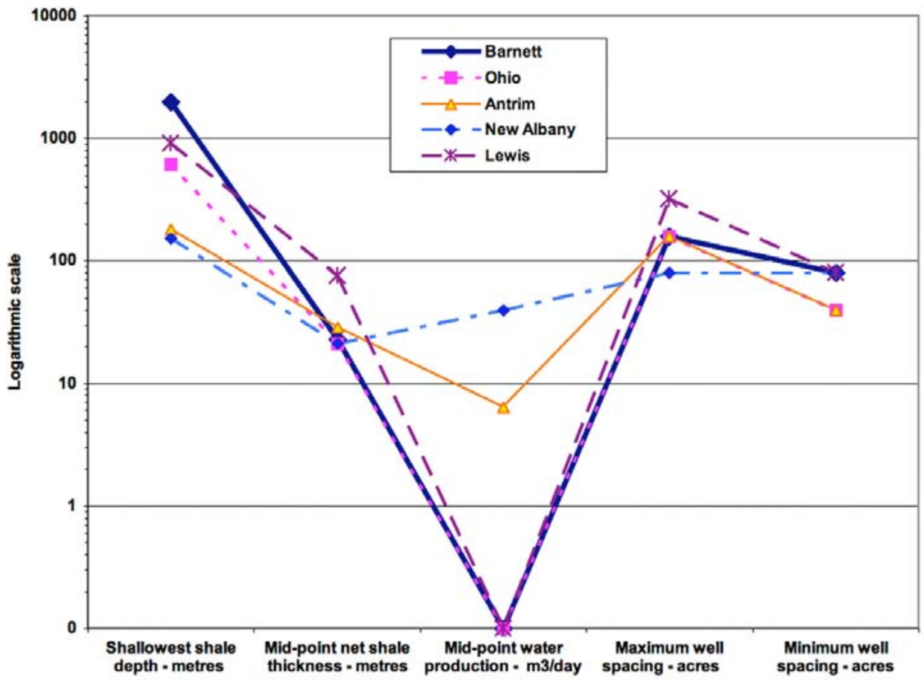

Figure 3-7 Selected properties of shale reservoirs in the U.S.

Source: American Association of Petroleum Geologists and Mike Mullen, Halliburton.

Figure 3-7 shows there is considerable variation in the depth of the producing shale formations in the U.S. The shallowest shale is less than 200 metres from the surface in the New Albany and Antrim shales; the deepest shale is between 2,000 and 2,500 metres deep in the Texas Barnett shale. Development of the shallow shale reservoirs could potentially impact fresh groundwater if dewatering is required to produce the gas or if the gas is at a similar depth to producing water wells. Gas production from deep shale may have an impact if large volumes of fresh water are withdrawn from aquifers for fracturing, as is done to stimulate the Barnett shale in Texas. The thickness of the Barnett shale means that a large volume of water is used; a large number of treatments are required as long-reach horizontal wells are drilled to communicate with and fracture as many natural fractures as possible. Some organic-rich shales in the Western Canada Sedimentary Basin are up to several hundred feet thick, but at the present time it is unknown if high-volume fractures, such as those employed in the Barnett shale, will be appropriate for any Canadian gas shales. It seems unlikely that such large volumes of water will be used in Alberta (see section 4.3.3). However, with respect to the Colorado shales, "the conditions in the Foothills may be similar to those of the Style C (Barnett-like) shale play of the U.S. and suggest that these parts of the Colorado should be seriously investigated for shale gas potential."[220] Using water as a fracturing fluid requires a specific mineralogy in that there must be little or none of a clay mineral commonly referred to as "smectite," which swells in contact with water thereby blocking pore throats and reducing gas production. Given present technology, water use in Alberta will be limited to shale zones similar to the Barnet shale, where smectite is a minor constituent.[221]

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[220] Hamblin, Anthony P. 2006. *The "Shale Gas" Concept in Canada: A Preliminary Inventory of Possibilities,* p. 54. Geological Survey of Canada, Open File 5384, *http://geopub.nrcan.gc.ca/* Use GEOSCAN and insert 5384 to locate the publication.

[221] In the Barnett shale the dominant clay mineral is illite.

The impacts will clearly vary with well density. As with CBM, the low volume of gas produced from each well means a company may need to drill many wells over a considerable land area to get enough gas for an economic project.[222] According to the Canadian Society for Unconventional Gas, "Due to the relatively low production rates anticipated from most gas shale wells, development of this resource will likely involve a fairly high density of wells similar to NGC [natural gas in coal] and the shallow gas fields in SE Alberta."[223] In the U.S., wells are generally drilled at very high densities, with one well per 40 to 80 acres for most vertically drilled shale gas wells.[224]

In some areas it may be possible to conduct horizontal or lateral drilling, with multiple bore holes from a single well pad, which will reduce the well density. Horizontal wells may be over a kilometre long, with the longest being approximately 1.5 kilometres.[225] Generally, this means that there will be fewer impacts on the surface, but the volume of water required for fracturing may still be high.[226] There is considerable debate and research regarding the effective drainage area for vertical and horizontal shale gas wells, and since it is likely that each shale gas reservoir will have unique drainage characteristics, each shale gas project may have unique well spacing requirements.

3.3.3 What are the government regulatory programs for shale gas?

At the time of writing, shale gas is subject to the same rules as conventional natural gas. However, due to some similarities between CBM and shale gas, "Key insights and recommendations from the multi-stakeholder consultation on natural gas in coal/coalbed methane may apply to shale gas."[227]

At the time of writing, Alberta Energy does not have any special provisions for shale gas, but the EUB recognizes that shale gas exploration and development is starting.[228]

In contrast, the British Columbia government has issued an assessment of shale gas potential in the northeast part of the province,[229] and the B.C. Oil and Gas Commission has invited applications for experimental shale gas schemes.[230]

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[222] Moorman, Richard. 2006. *Developing a Canadian Shale Gas Strategy: How Can You Do It Well?* slide 17., The Canadian Institute's 2nd Annual Capturing Opportunities in Canadian Shale Gas Conference, January 31 and February 1, Calgary.

[223] Canadian Society for Unconventional Gas. Undated. *Industry Facts and Figures: Shale Gas.* Scroll to find the section on Shale Gas at *http://www.csug.ca/faqs.html#Sa8*

[224] Well density varies considerably. Vertical wells in one area in the U.S. have a drainage area of 5 – 20 acres and horizontal wells drain from 18 – 62 acres. Shelby Geological Consulting. 2006. *The Fayetteville Shale Play – A Bonanza for Arkansas?* Norman Lecture Series, Arkansas Tech University, October 4, slide 23, *http://pls.atu.edu/physci/geology/shale20061006.ppt#326,20,Shelby*

[225] Duncan, Lee. 2006. *Directional Drilling in North America,* The Canadian Institute's 2nd Annual Capturing Opportunities in Canadian Shale Gas Conference, January 31 and February 1, Calgary.

[226] Gardes, Bob. 2006. *Canadian Shale Gas: A Technology Drive Resource in its Infancy,* The Canadian Institute's 2nd Annual Capturing Opportunities in Canadian Shale Gas Conference, January 31 and February 1, Calgary.

[227] Rauschning, Sharla. Alberta Energy. 2006. *Alberta's Shale Gas Regulatory Structure,* slide 16. The Canadian Institute's 2nd Annual Capturing Opportunities in Canadian Shale Gas Conference, January 31 and February 1, Calgary.

[228] The EUB refers to shale gas in Alberta Energy and Utilities Board. 2006. *ST98-2006: Alberta's Energy Reserves 2005 and Supply/Demand Outlook*, p. 5, *http://www.eub.ca/docs/products/STs/st98_current.pdf* See also, Alberta Energy and Utilities Board. 2006. *Management of Commingling in the Wellbore, Control Well Requirements Coalbed Methane and Shale Gas, http://www.eub.ca/portal/server.pt/gateway/PTARGS_0_212_820116_0_0_18/* .

[229] British Columbia Ministry of Energy, Mines and Petroleum Resources. 2005. *Shale Gas Potential of Devonian Strata, Northeastern British Columbia, Canada, http://www.em.gov.bc.ca/subwebs/oilandgas/petroleum_geology/uncog/shale.htm*

[230] Oil and Gas Commission, British Columbia. 2004. *Information Letter #OGC 04-32 Section 100 Status for Shale Gas Projects, http://www.ogc.gov.bc.ca/documents/informationletters/OGC%2004-32%20Status%20for%20Shale%20Gas%20Projects.pdf* The B.C.

3.4 Tight gas

3.4.1 What is tight gas?

Tight gas is similar to conventional gas, except that it comes from reservoirs with low porosity and low permeability.[231] The low permeability may be due to the fine nature of the sediments or compaction or because the spaces between the sands are "cemented" with deposits from water in the formation (e.g., carbonates or silicates). There is no exact definition of tight gas in Canada but "a generally accepted industry definition is reservoirs that cannot be produced at economic flow rates or that do not produce economic volumes of natural gas without assistance from massive stimulation treatments or special recovery processes and technologies."[232, 233] The U.S. has a definition, since it provided tax credits for certain tight formations.[234] Tight sands are found in the deep basin that lies east of the Foothills in Alberta and northeastern British Columbia, where they may be referred to as "deep basin" gas (see Figure 3-8). As the price of natural gas has increased and advanced technologies have been developed, it is becoming increasingly economic to develop deep basin gas[235] and companies are now increasing their level of activity in the deep basin area.[236] Unless there is an opportunity for directional drilling, the density of wells for tight gas is usually higher than for conventional gas and well spacing may be between 80 and 320 acres.[237] In some extreme situations in the U.S. the density has been much higher.[238]

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government has also conducted a study on *Shale Gas Potential of Devonian Strata, Northeastern British Columbia,* http://www.em.gov.bc.ca/subwebs/oilandgas/petroleum_geology/uncog/shale.htm#Studies

[231] Centre for Energy Information. 2006. *Natural Gas from Tight Sands,* *http://www.centreforenergy.com/generator2.asp?xml=/silos/ong/NatGasFromTightSands/tightSandsOverview01XML.asp&template=1,2,3*

[232] Centre for Energy. 2007. *Natural Gas from Tight Sands: What is Natural Gas from Tights Sands?* *http://www.centreforenergy.com/silos/ong/ET-ONG.asp*

[233] National Energy Board. 2006. *Short-Term Natural Gas Deliverability 2006-2008: An Energy Market Assessment.* p. 4, *http://www.neb-one.gc.ca/energy/energyreports/emagasstdeliverabilitycanada2006_2008/emagasstdeliverabilitycanada2006_2008_e.pdf* The National Energy Board includes tight gas with conventional gas as "at present there is no generally agreed upon criteria to identify tight gas."

[234] The U.S. Natural Gas Policy Act of 1978, section 107(c), provided for tax credits for designated tight gas formations. A summary of the Act is available at *http://www.eia.doe.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ngact1978.html* Tight gas sands are defined as having less than 0.1 millidarcy permeability. Kent F. Perry, Michael P. Cleary, John B. Curtis, *New Technology for Tight Gas Sands,* World Energy Council , *http://www.worldenergy.org/wec-geis/publications/default/tech_papers/17th_congress/2_1_16.asp#Heading2*

[235] Hayes, Brad. J.R., 2003. *The Deep Basin – A Hot "Tight Gas" Play for 25 Years,* Search and Discovery Article # 10052, *http://www.searchanddiscovery.net/documents/2003/hayes/index.htm* See also, Hayes, Brad J.R., Marc Junghans, Kim Davies and Murray Stodalka, *New Deep Basin Gas Plays at Hooker, Alberta – Extending Deep Basin Prospectivity Southward,* Search and Discovery Article #10051, *http://www.searchanddiscovery.net/documents/2003/hayes02/index.htm*

[236] Jaremko, Gordon. 2005. "Company sees 'incredible' potential in Alberta basin gas," *Edmonton Journal,* December 20, p. F1. The article reports on Shell Canada's interest in the Rocky Mountain foothills near Hinton, where the company purchased rights to 270 square kilometers in a December auction. Burlington Resources Canada Ltd., prior to its take-over by ConocoPhillips, purchased the rights to over 4,000 sq km. or about half the prospective acreage in the Deep Basin of northwestern Albert and eastern British Columbia. See also "Talisman notches B.C., Alberta gas strikes", *Petroleum News, February 5, 2006,* *http://www.petroleumnews.com/pntruncate/88314403.shtml*

[237] For example, eight wells per section will be required in the Callum Thrusted Bellly River tight sands. Compton Petroleum Canada. 2006. *CAPP Presentation,* June 14, slide 19, *http://www.comptonpetroleum.com/06Slides/06index.html* Compton likens the area to the Greater Green River Basin in Wyoming, *http://www.comptonpetroleum.com/02Core/s_alberta.html*

[238] In part of the Jonah and Pinedale fields which lie in the northern part of the Green River Basin, well densities of up to 1 well per 10 acres have been approved. Anadarko, 2006. *Operations by Region, Wyoming Pinedale /Jonah,* *http://www.anadarko.com/operations_by_region/us_rockies/wyoming_pinedale_jonah.asp?r=1* See also Bureau of Land Management Wyoming. 2006. *Jonah Infill Drilling Project: Final Environmental Impact Statement,* especially Chapter 4 Environmental Consequences and Mitigation Measures, and the Board's *Record of Decision,* *http://www.wy.blm.gov/nepa/pfodocs/jonah* The high density of wells requires large volumes of water for drilling and there are also large volumes of produced saline water. In parts of Garfield County, Colorado, up to one well every 10 acres is allowed, but no more than one surface pad "on a given quarter quarter section" (that is, every 40 acres). Oil and Gas Commission of the State of Colorado. 2006. *Order Nos. 169-34 and 440-35, In the Matter of Promulgation and Establishment of Field Rules to Govern Operations in the Rulison and Parachute Fields, Garfield County, Colorado,* *http://oil-gas.state.co.us/orders/orders/139/64.html*

Shallow gas was described in the section on conventional gas, but it is sometimes considered a form of tight gas, since the low pressure and low permeability shallow reservoirs need stimulation to produce economic amounts of gas. As with other forms of tight gas, shallow gas requires a high well density to extract the gas and, due to the shallow nature of the formations, pad or directional drilling is not usually feasible. However, the development requirements and potential impacts of shallow gas on fresh groundwater are quite different from other tight gas reservoirs.

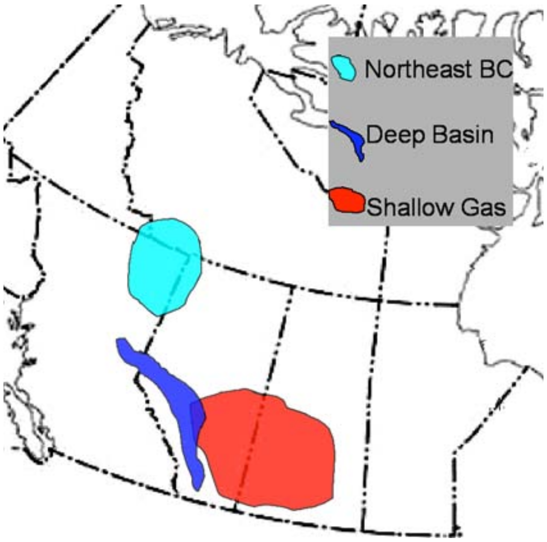

Figure 3-8 The extent of tight gas in western Canada

Source: Mike Dawson, Canadian Society for Unconventional Gas (adapted)

As noted in section 1.2, the EUB does not have a separate classification for tight gas, and production figures in Alberta are included with conventional gas.

3.4.2 How can tight gas development affect water?

The type of drilling for tight gas will vary depending on the formation and operator. In some cases, underbalanced drilling will be used. Underbalanced drilling means that pressure in the wellbore is below that in the formation to prevent drilling fluids entering and damaging the formation). Some types of underbalanced drilling use water.[239]

Tight sands reservoirs do not usually contain much mobile water, so are not likely to need dewatering,[240] but wells do need stimulation to enable the gas to flow to the wellbore. Special fracturing fluids have been designed for tight gas formations, but where water is used in the fracturing fluid, the water consumption may be high. The amount of fracturing and the number

[239] Underbalanced drilling can be carried out in a number of ways including air-drilling, drilling with an air-water mist and injection of an inert gas (usually nitrogen) foam. The foam may contain water. Petroleum Technology Transfer Council. Undated. *Underbalanced Drilling,* http://www.pttc.org/solutions/504.pdf N.B. Underbalanced drilling is normally used in the horizontal section of a well. Conventional drilling techniques are normally used to get to the kickoff point so a well that is underbalanced has a conventional vertical section, including normal surface casing, and then a horizontal section.

[240] Petroleum Technology Alliance Canada. 2006. *Filling the Gap: Unconventional Gas Technology Roadmap,* p. 35, http://www.ptac.org/cbm/dl/PTAC.UGTR.pdf "Tight gas and shale reservoirs typically host less water, but can also contain light hydrocarbons that can affect gas production." See also Alberta Energy and Utilities Board *Directive 008,* Section 1. The production casing comes to surface and due to the low pressure of the gas, surface casing is not needed to hold the wellhead or deal with pressures. In an area of SE Alberta (from Saskatchewan Border to T37 and R21) the requirement for surface casing is waived for wells drilled above the base of the Second White Specs.

of fracture treatments required will depend on the formation; some formations may be fractured repeatedly.

3.4.3 What are the government regulatory programs for tight gas?

The EUB requirements for conventional natural gas apply to tight gas.

4. Development of the Resource

This chapter reviews each stage in gas production, from seismic operations, well drilling and fracturing to the abandonment of wells, to examine the potential impacts that these operations might have on water.

4.1 Seismic exploration

Seismic exploration is needed to locate deep gas-bearing zones.[241] Seismic exploration involves the use of an explosive or non-explosive energy source at or near the ground surface to produce vibrations for acquiring exploration data. Explosive energy sources use dynamite or other explosives in a 10-cm drilled shot hole that is 20 metres or less in depth. A non-explosive energy source is mechanically generated on the ground surface by using a vibroseis unit or an air gun.

The energy source produces vibrations that are recorded by strategically placed geophones and provide subsurface information that enables potential hydrocarbon reservoirs to be identified. To minimize any risk of impacts due to vibrations, a company must follow the setback distances as set out in the *Exploration Regulation,* which is administered by Alberta Sustainable Resource Development.[242] The setback distances are the minimum distance permitted between the vibration source point and water wells, buildings, and so on. Despite the regulated setback distances and the outcome of studies,[243] some people think that seismic surveys may still occasionally impact a water well. It is estimated that in up to 10% of water well investigations conducted by geophysical inspectors in Alberta problems are "quite likely associated with geophysical operations.[244] However, it is very difficult to prove a connection, especially if the condition of the water well is not known prior to the seismic activity. Thus it is advisable for landowners to arrange for the company to conduct a production test on their water wells before giving permission for a seismic survey on their lands.

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[241] For shallow gas development companies usually rely on existing well log data.

[242] Government of Alberta. *Exploration Regulation,* http://www.qp.gov.ab.ca/documents/Regs/2006_284.cfm?frm_isbn=9780779720651

[243] Ross, I.C. 1995. *Summary of Previous Studies on the Effect of Seismic Shooting on Water Wells in Alberta,* The Groundwater Centre, http://www.10704.com/pdf/misc/seismic_shooting.pdf This report is posted on the website of Hydrogeological Consultants Ltd., at http://www.hcl.ca/reports.asp In studies cited, some large explosive charges were used close to water wells, but, as the Abstract states, "No damage was ever observed, and, although some data suggested the possibility of slight changes in transmissivity following the huge close-in shots, no permanent changes were observed which would have been noticeable in a domestic well far less explain the catastrophic damage which constitutes most claims involving seismic activity."

[244] Alberta Sustainable Resource Development, Land Management Branch provided the following information in a personal communication with Mary Griffiths, November 8, 2006:Geophysical inspectors with Sustainable Resource Development (SRD) investigated 157 water well related issues associated with geophysical activity during the 30 months prior to November 2006. These are only the water well-related issues that have come to SRD's attention during that time frame. Due to the ambiguity of identifying cause and effect, it is difficult to attain exact statistics, but an *estimate* of water well issues associated with geophysical activity (directly, indirectly or perceived) is that:

- Up to 10% of water wells investigated are quite likely associated with geophysical operations.
- Up to 30% of water well issues investigated prove inconclusive in that the available information does not substantiate or disprove a causal link to geophysical activity.
- Up to 60% of water well issues investigated are related to other causes, such as natural occurrences, natural well deterioration, lack of servicing and maintenance, equipment failure (electrical and mechanical), and human activities.

Any landowner who thinks that a water well has been impacted by seismic operations (or has other concerns about a seismic survey) should contact Alberta Sustainable Resource Development and ask a geophysical inspector to investigate.[245]

If it appears that a water well has been damaged, the landowner should seek compensation from the company. In addition, the Farmers' Advocate Office may be able to assist through the Water Well Restoration or Replacement Program.[246]

If explosives are used as an energy source to generate the vibrations, a company must plug the hole as set out in the regulations to prevent water and contaminants from entering any aquifers.[247] After the survey has been conducted landowners should check to ensure that all shot holes have been properly plugged to prevent surface contaminants from contaminating shallow groundwater, and that no water is flowing from open shot holes. [248]

The Alberta Surface Rights Federation expressed concern that shot holes have to be plugged only a metre below the surface, and fear that pollutants, such as *E. coli* bacteria, might wash down the hole into the groundwater.[249] The government report, *Water Wells that Last for Generations,* recommends that a landowner negotiate with a seismic company to put the plastic plug closer to the bottom of each hole, and fill from the plug to the ground surface with only bentonite pellets.[250]

A seismic/groundwater survey is underway in Alberta to determine whether current legislated shot hole abandonment methods are adequate to prevent overland flow (surface water) from reaching an aquifer via a seismic shot hole that has been permanently abandoned in accordance with current requirements.

4.2 Well drilling

There are several stages to drilling and completing a gas well that might affect shallow aquifers if there are problems with the drilling process. Impacts may relate to the water-based mud used for the drilling process, the construction of the well casing, the fracturing of the formation to enable the gas to flow to the wellbore or the commingling of production from different formations. If the gas-bearing formation contains water there may also be impacts associated with the diversion of fresh water.

Due to the potential for impact on shallow groundwater, baseline water well testing is required before a company drills a shallow CBM well (see section 3.2.3.1). Some companies offer to test

[245] To contact a geophysical inspector, call Alberta Sustainable Resource Development at. 780-427-3932. To call toll free using the government RITE line, first dial 310-0000.

[246] The Office of the Farmers' Advocate of Alberta. 2006. *32nd Annual Report,* p. 7 shows the proportion of energy files that relate to seismic operations, but there are no specific figures on the number of water well cases that relate to seismic exploration. See p.11 for information a report on the Water Well Restoration or Replacement Program for 2005-2006. The report is online at http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/ofa10882

[247] Government of Alberta. *Exploration Regulation,* section 42, http://www.qp.gov.ab.ca/documents/Regs/2006_284.cfm?frm_isbn=9780779720651

[248] It is possible that shallow groundwater could be affected as a result of contaminated surface water entering unplugged shot holes. Edo Nyland, Professor Emeritus, University of Alberta, personal communication with Mary Griffiths, January 2, 2007.

[249] The Alberta Surface Rights Federation points to the example of Wyoming, where a company is required to fill the shot hole from bottom to top with bentonite or some equivalent method. See Wyoming Oil and Gas Conservation Commission. Undated. *Rules, Chapter 4, section 6. Geophysical/seismic operations,* http://wogcc.state.wy.us/db/rules/4-6.html

[250] Alberta Agriculture, Food and Rural Development. 2001.*Water Wells That Last For Generations,* Module 8. http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/wwg404 Call 1-800-292-5697 (toll free) for a printed version.

a landowner's water well before they undertake drilling any gas (or oil) well and landowners have the ability to request and negotiate for water well testing at the time the company is requesting a surface lease. Landowners may want to negotiate a wider range of testing (such as all water wells within 880 metres or more, including adjacent landowners) or testing of surface waters or spring-fed ponds, and so on.

4.2.1 Drilling mud

When a gas well is drilled, drilling mud is circulated down the drill pipe to cool the bit, maintain the desired pressure in the wellbore, bring the drill cuttings to the surface and, most importantly, form a filter cake to stabilize the hole and prevent communication between zones.

Drilling mud is often a water-based clay mixture (especially when drilling shallow wells), but a range of substances may be added to it, such as bactericides, emulsifiers, foaming agents, polymers and surfactants. Drilling mud may be oil based if, for example, there is a risk of encountering a water-sensitive rock formation (e.g., where water could cause clays to swell).[251] Companies need to assure themselves that the volume of additives they are using to control such things as mud viscosity are not impacting groundwater. This calculation has to be specific to the mud volume, depth of well and area of the province. If viscosity is not controlled, there is a risk of lost circulation, stuck pipe, and other problems.

Each additive to a drilling mud has different effects. For example, caustic soda is used to control the pH of the mud under acidic conditions. The use of caustic soda leads to more alkaline or basic conditions.[252]

If there is loss of circulation during drilling, i.e., the drilling mud does not return to the surface, the drilling mud may enter the surrounding groundwater.[253] Landowners have expressed concern that the water used for drilling mud could be contaminated with *E.coli* or fecal coliforms if it is taken from a river or dugout, and that it could contaminate fresh aquifers. They want drilling mud to be constituted with potable or treated water.[254] As noted in section 2.2, the MAC recommended that this should be investigated as part of the study of drilling fluids.[255] The EUB has recognized that the use of untreated water in drilling fluids is a concern to landowners[256] and is commissioning a third-party report on the subject.

One report, written prior to the MAC recommendation, indicates that the direct health risk from surface waters can be addressed "by effective disinfection of those waters before they are used

[251] See, for example, Halliburton. 2006. *Drilling Fluid Additives,* http://www.halliburton.com/ps/Default.aspx?navid=28&pageid=64&prodgrpid=MSE%3a%3aIQU4J8JSZ

[252] Cullimore, Roy. 2005. *Potential Biological Impact on Shallow Aquifers from Using Surface Water as a Drilling Fluid,* p. 13. Droycon Bioconcepts Inc. for EnCana. N.B. More alkaline or basic conditions could increase the risk that biological encrustations will occur, which might impact the flow of water through the affected area close to the well. This could be an issue if drilling a water well, as it could impair the flow of water into the well, but it will not affect the aquifer.

[253] A reviewer has pointed out that loss of circulation happens when water wells are being drilled and is not unique to the drilling of oil and gas wells. The source cited is the evidence of a water well driller, Mr. Doering, at the EUB hearing on EnCana Corporation Application for 15 Wells, a Pipeline and a Compressor Addition, Wimborne and Twining Fields.

[254] Landowners want the same conditions to apply as when a water well is drilled. When drilling a water well, "No driller shall use a fluid or substance in a drilling operation that may cause an adverse effect on the environment, human health, property or public safety." *Water (Ministerial) Regulation,* section 50, http://www.qp.gov.ab.ca/documents/Regs/1998_205.cfm?frm_isbn=9780779722945

[255] Government of Alberta. 2006. *Coalbed Methane/Natural Gas in Coal Multi-Stakeholder Advisory Committee Final Report,* recommendation 3.4.2, http://www.energy.gov.ab.ca/docs/naturalgas/pdfs/cbm/THE_FINAL_REPORT.pdf

[256] Alberta Energy and Utilities Board. 2006. Decision 2006 –102, *EnCana Corporation Application for 15 Wells, a Pipeline and a Compressor Addition, Wimborne and Twining Fields,* p. 6, http://www.eub.ca/docs/documents/decisions/2006/2006-102.pdf

(primarily in drilling fluids)."[257] The author points out that the key is "effective" disinfection: chlorination will eliminate the majority of the *E. coli* bacteria, but only a minority of other types of coliform bacteria will be eliminated and some of those remaining can adapt and grow in the groundwater environment. [258] While chlorine will kill some bacteria in water at the surface, any residual chlorine will be neutralized within the natural biomass present in the ground water within a month of injection.[259] Thus, chlorine disinfection does not have a lasting effect once it is underground and some types of coliform bacteria survive and flourish in groundwater. As stated in the report, "These bacteria can become integrated into the natural bacterial communities within the ground water environment and do not normally pose a significant health threat to the users of that ground water. It can therefore be considered that surface water, even if it possesses coliform bacteria, does not pose a long term threat to the ground water even in the immediate location of the new oil and gas well."[260] It seems that "Any health risks are likely to be of short duration (less than seven days) and limited to regions close to the well (within two metres)."[261] If the drilling of a gas well goes according to plan then the impacts of surface water injection are probably going to be limited to the local environment. This view seems to be supported by various studies, although the distance bacteria travel will depend on the geology.[262]

It has been suggested that deep saline groundwater could be used as a source of drilling water in water-short areas. However, there are environmental risks associated with the use of saline groundwater. If salt water is spilled on the ground, the salt water must be recovered and the spill site must be remediated. If there is lost circulation during drilling, saline groundwater could negatively impact an aquifer. Moreover, drill cuttings mixed with saline drilling mud cannot be land spread without having a salt-management plan. Therefore, the use of saline groundwater in the drilling of hydrocarbon wells would be practical only under a limited number of conditions.[263] Various substances, such as slowly degrading cellulose fibre, sawdust or walnut

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[257] Cullimore, Roy. 2005. *Potential Biological Impact on Shallow Aquifers from Using Surface Water as a Drilling Fluid,* p.4. Droycon Bioconcepts Inc. for EnCana. The full report gives a careful examination of the various factors affecting coliform levels.

[258] Roy Cullimore. Droycon Bioconcepts Inc., personal communication with Mary Griffiths, July 27, 2006.

[259] Cullimore, Roy. 2005. *Potential Biological Impact on Shallow Aquifers from Using Surface Water as a Drilling Fluid,* Droycon Bioconcepts Inc. for EnCana, p.19.

[260] Cullimore, Roy. 2005. *Potential Biological Impact on Shallow Aquifers from using Surface Water as a Drilling Fluid,* Droycon Bioconcepts Inc. for EnCana, p. 5. Roy Cullimore, Droycon Bioconcepts Inc., has indicated in a personal communication with Mary Griffiths, July 27, 2006, that the word "threat" should perhaps be qualified as a "hygiene threat".

[261] Cullimore, Roy. 2005. *Potential Biological Impact on Shallow Aquifers from using Surface Water as a Drilling Fluid,* Droycon Bioconcepts Inc. for EnCana, p.2.

[262] Roger Clissold, Hydrogeological Consultants Ltd., compared data from approximately 1,000 water wells drilled by rotary rigs (which are similar to those used to drill gas wells) and 1,000 drilled using other rigs and found no significant difference in the proportion of coliform bacteria in the groundwater. Water wells are usually chlorinated after being drilled, but until 20 years ago this was not common practice. Most of the studies done on water well contamination are in limestone areas, where the water is not filtered in any way. Clays and sands filter the water that flows through them, so it is unlikely that any bacteria would be found more than 20 metres from the wellbore. Very coarse gravel does not filter so well, and one study in the U.S. showed that bacteria moved up to 500 metres from the source. Roger Clissold, personal communication with Mary Griffiths, January 19, 2007.

See also U.S. Environmental Protection Agency. 2006. *Occurrence and Monitoring Document for the Final Ground Water Rule,* Chapter 4: Microbial Contaminant Fate and Transport, *http://www.epa.gov/ogwdw/disinfection/gwr/pdfs/support_gwr_occurance-monitoring*.pdf This report deals primarily with flows from septic tanks, sewage lagoons, etc., which are a constant source of contaminants, into adjacent shallow aquifers, so it is not directly relevant to drilling mud, where any pathogens will to some extent be bonded in the mud. However, it provides an overview of the distances that free pathogens (not bonded in drilling mud) may travel in different types of material. N.B. There is no karst (limestone) in the Prairie region of Alberta and sedimentary deposits often contain a mixture of fine particles to which any pathogens are likely to bond within a relatively short distance.

[263] Roger Clissold, Hydrogeological Consultants Ltd., personal communication with Mary Griffiths, January 24, 2007.

shells, may be used to “plug” the formation if there is loss of circulation while drilling.[264] The exact nature and speed of degradation will depend on the substances used and on whether the groundwater conditions allow these materials to degrade.[265] It will also depend upon depth and time frame considerations. Although the impacts of lost circulation will most likely remain close to the wellbore, [266] the concern remains that loss control materials[267] (LCM) may affect groundwater. However, “While this concern needs to be addressed, most LCM have only short active life spans and are not easily or quickly degraded biologically.”[268]

Drilling techniques and substances vary, depending on the formation. For example, in some tight sands, underbalanced drilling is used, which involves drilling with foams or insert gases instead of water.[269] Different drilling and completion techniques may be used in shales and they may vary within the shales.[270]

The Petroleum Services Association of Canada provides a list showing the toxicity threshold of drilling fluid products.[271] This list was designed to work with EUB *Directive 50: Drilling Waste Management.* A landowner can also ask to see a copy of the Material Safety Data Sheet (MSDS) for a product being used for drilling or fracturing or can search on the Internet if he or she knows the name of the product(s) used.[272] A MSDS describes the characteristics of the concentrated product to protect workers and it will often be diluted before it is used. Some of the substances are toxic, but they cannot be used in concentrations that would contravene Alberta’s legislation, which prohibits the release of any substance in a concentration that causes or may cause a significant adverse effect.[273]

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[264] There are no specific requirements for materials that are used for handling lost circulation. Brenda Austin, Alberta Energy and Utilities Board, personal communication with Mary Griffiths, October 5, 2006.

[265] “All three have some potential to trigger biological activity, but tend to be recalcitrant (difficult to degrade biologically, long lasting) in the type of environment that would occur in aquifers.” These various substances are mostly made from organic matter that degrades relatively slowly (once any oxygen had been consumed by the microorganisms in the ground water). If there is some microbial activity breaking down the organic matter, it is thought that the resultant gases (e.g., methane) will form a temporary foam barrier, while any slimes formed as a result of this bacterial action could also plug the formation and help to seal off the lost-circulation leakage. Cullimore, Roy. 2005. *Potential Biological Impact on Shallow Aquifers from Using Surface Water as a Drilling Fluid,* p. 14 - 15. Droycon Bioconcepts Inc. for EnCana.

[266] Cam Cline, EnCana, personal communication with Mary Griffiths, October 27, 2006.

[267] Also referred to as “lost circulation material”.

[268] Cullimore, Roy. 2005. *Potential Biological Impact on Shallow Aquifers from Using Surface Water as a Drilling Fluid,* p. 2 Droycon Bioconcepts Inc. for EnCana.

[269] Centre for Energy. *Natural Gas: Tight Sands: Overview. How is Gas from Tight Sands Produced?* http://www.centreforenergy.com/silos/ong/ET-ONG.asp

[270] Moorman, Richard. 2006. *Developing a Canadian Shale Gas Strategy: How Can You Do it Well?* slide 26, The Canadian Institute’s 2nd Annual Capturing Opportunities in Canadian Shale Gas Conference, January 31 and February 1, Calgary.

[271] Petroleum Services Association of Canada. 2005. *Drilling Fluid Product Listing for Potential Toxicity Information,* http://www.psac.ca/mudlist/pdf/mud_list.pdf The toxicity threshold is based on potential acute effects. The thresholds are expressed in terms of EC50, which refers to a dose-response relationship, where the value given (the EC50) is 50% of the dose that would give the maximum possible response (see “introducing Dose-Response Curves at http://www.graphpad.com/curvefit/introduction89.htm). A list of the chemicals used in the past is also available at http://www.psac.ca/mudlist/index_list.html The list of drilling fluids was designed for use with EUB *Directive 051: Drilling Waste Management,* and is not designed to indicate the toxicity should any of the substances accidentally get into fresh water.

[272] The Canadian Centre for Occupational Health and Safety web site at http://www.ccohs.ca/ provides some information but Material Safety Data Sheets (MSDS) are only available to subscribers (though the site offers a free trial). See also Workers’ Compensation Board, Northwest Territories and Nunavut. 2000. *Understanding an MSDS* at http://www.oshforeveryone.org/ntnu/files/ccohs/msds.pdf and Alberta Employment, Immigration and Industry. 2004. *WHMIS Information for Workers,* Safety Bulletin CH007, Workplace Health and Safety Bulletin, http://www.hre.gov.ab.ca/documents/WHS/WHS-PUB_ch007.pdf For a brief explanation of the Microtox test that is used to determine the toxicity, see *Summary of Microtox Systems – Where They Stand Today* at http://www.sciencelives.com/microtox.html

[273] Government of Alberta. 1992 and updates. *Environmental Protection and Enhancement Act,* http://www.qp.gov.ab.ca/documents/Acts/E12.cfm?frm_isbn=0779746678 Section 109 relates to the release of substances into the environment.

After drilling is complete, the way in which the drilling mud is disposed of will depend on the substances it contains. The EUB's requirements for the disposal of drilling waste aim to prevent harmful effects on land and water and depend on the toxicity and nature of the drilling mud constituents. They are set out in *Directive 50.* [274] Solids from the drilling process may be sent to landfill. One common off-site disposal process for certain types of drilling mud is landspraying while drilling. Providing the chemical composition of the drilling mud meets required toxicity standards, the land is not too steep, not frozen and far enough away from a water body, etc. the waste may be sprayed on the land.[275] Allowed on-site and off-site disposal practices are based on "loading rates," which are estimates of the amount of waste the environment can handle without irreparable damage occurring. Regulators set these rates on the assumption that the contaminants (which may include salts, metals and hydrocarbons) will become diluted in the environment.[276] Landowners should be aware of exactly what chemicals are in the drilling mud and their concentration. They should also find out the volume of waste and when it will be spread, before deciding whether to accept drilling mud on their land.[277]

A study of landspraying while drilling on Crown Land showed that over one quarter of the sites studied failed to meet the requirements set out in the directive during the period 1997–2001.[278] This spraying was on native prairie that could not be tilled; since the study was conducted, spraying on native prairie has been discontinued. In 2005, the EUB conducted 166 drilling waste inspections of disposal sites that did not require pre-approval (e.g., mix-bury-cover, landspray, landspray while drilling, and pump-off) and almost 10% were in the EUB's "major unsatisfactory" category.[279] The most common reasons for major noncompliance were landspraying closer than allowable limits to surface water, waste spread on a slope with a greater than 5% incline, and inadequate sump construction. When conducting its inspections, the EUB targets most audits on locations where there is most risk, so the non-compliance rate is not representative of all operations. To avoid problems, the Pembina Institute suggests it is preferable for drilling mud to be taken to an approved waste disposal site,[280] with waste water being sent for deep well disposal, below the base of groundwater protection. [281]

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[274] Alberta Energy and Utilities Board. 1996. *Directive 050: Drilling Waste Management,* http://www.eub.ca/docs/documents/directives/Directive050.pdf

[275] Alberta Energy and Utilities Board. 1996. *Directive 050: Drilling Waste Management,* section 4.3, http://www.eub.ca/docs/documents/directives/Directive050.pdf

[276] Thus, for example, a company may land spread drilling mud with an application rate of up to 100 kg/ha lead. Alberta Energy and Utilities Board. 1996. *Directive 050: Drilling Waste Management,* Appendix 2, Table 1, Summary of Loading Criteria for Disposal Methods, http://www.eub.ca/docs/documents/directives/Directive050.pdf

[277] It is also important to consider the cumulative load on the land and the way in which the spread chemicals will react with the existing soil chemistry and plant species. Of course, it is not acceptable to spread drilling mud on land that is used for organic production, or if the land is adjacent to organic operations (including organic bee hives).

[278] Landspraying While Drilling Review Team. 2003. *Landspraying While Drilling (LWD) Review.* Public Lands and Forests Division, Alberta Sustainable Resource Development, December. The study was conducted in the Medicine Hat Area, for work done between 1997 and 2001. Over 28% of file audits and 29% of field audits were judged as having "significant problems or deficiencies". A field audit found that in 17% of all projects (and half the projects that failed), some spraying was conducted outside the approved area; 8% of all projects (26% of those that failed) had load rates that were too heavy. Four percent of all cases had no approval.

[279] Alberta Energy and Utilities Board. 2006. *ST 99-2006: Provincial Surveillance and Compliance Summary 2005,* p. 92, http://www.eub.ca/docs/products/STs/st99_current.pdf

[280] Despite the fact that a company is liable for any contamination that results from its activities, some banks have asked for an environmental assessment of sumps or sites used for drilling waste disposal before allowing a person to use their property as security for borrowing. A bank may also want an environmental audit before they give a purchaser a mortgage. If a landowner encounters such a problem, the Farmers' Advocate Office may be able to give advice.

[281] Alberta Energy and Utilities Board. 1996. *Directive 050. Drilling Waste Management,* Section 6: Alternative Disposal Options, http://www.eub.ca/docs/documents/directives/Directive050.pdf

4.2.2 Casing the well

When a well is being drilled, surface casing is usually put in place as a means of controlling pressure at the wellhead after the first part of a well has been drilled. It may also to help protect groundwater.[282] Cement is pumped around the well casing to protect movement of fluid and gases between different zones along the wellbore.[283] After the drilling of a well is complete, production casing is installed.[284] The depth of the surface casing will depend on the type and depth of the well. Where the surface casing cement does not cover all fresh water aquifers (or has been waived), the next casing string (which may be an intermediate casing or production casing) must be cemented all the way to the surface to ensure that there is no pathway for migration of water or gas along the wellbore.[285] A cement bond log is run to ensure that the cementing is complete if cement returns are not maintained at the surface during cementing operations on any casing string. The EUB casing requirements to protect non-saline groundwater are summarized in *Bulletin 2005-04: Shallow Well Operations*.[286]

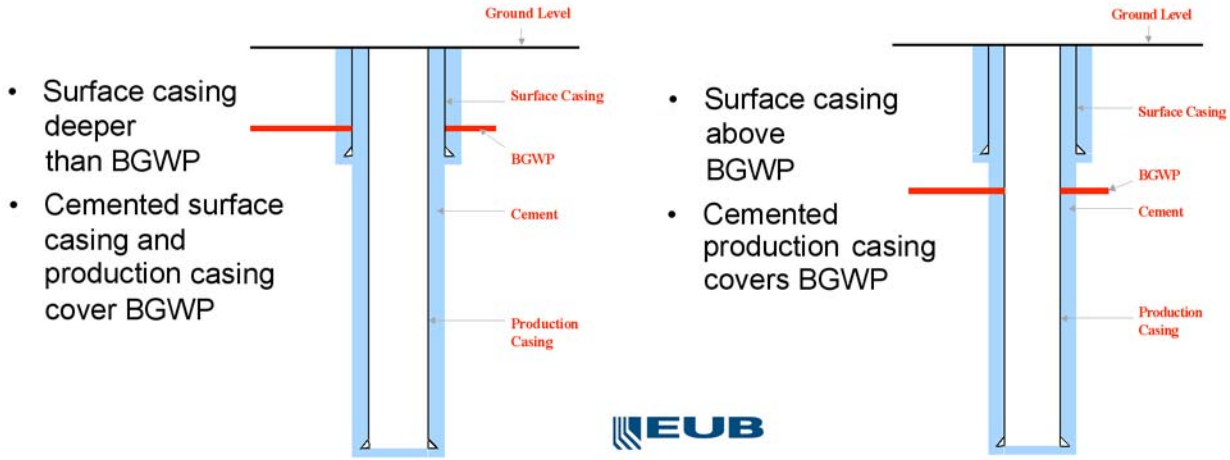

Figure 4-1 Well casing to protect non-saline groundwater
Source: Alberta Energy and Utilities Board (adapted)

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282 Alberta Energy and Utilities Board. 1997. *Directive 008: Surface Casing Depth Minimum Requirements.* In some shallow gas wells the requirement for surface casing may be waived, or it may not extend to the base of groundwater protection. For various views on the need for surface casing to cover all non-saline groundwater, see Alberta Energy and Utilities Board. 2006. *Decision 2006 –102, EnCana Corporation Application for 15 Wells, a Pipeline and a Compressor Addition, Wimborne and Twining Fields,* section 5.2, p. 7-11, http://www.eub.ca/docs/documents/decisions/2006/2006-102.pdf

283 Alberta Energy and Utilities Board. 1990. *Directive 009: Casing Cementing Minimum Requirements.* For information on cementing see, for example, BJ Services Company. 2001 *Cementing Services,* http://www.bjservices.com/website/ps.nsf/CementingFrameset?openframeset and Schlumberger. 2006. *Cementing Services,* http://www.slb.com/content/services/cementing/index.asp?

284 For a good summary of the different types of casing, see Alberta Energy and Utilities Board. 2006. *Decision 2006-102 EnCana Corporation Application for 15 Wells, a Pipeline and a Compressor Addition, Wimborne and Twining Fields,* http://www.eub.ca/docs/documents/decisions/2006/2006-102.pdf

285 Alberta Energy and Utilities Board. 1990. *Directive 009: Casing Cementing Minimum Requirements,* http://www.eub.ca/docs/documents/directives/Directive009.pdf Typically surface casing is 10% of the vertical depth of a well and in deep wells this is enough to protect shallow aquifers. If the surface casing depth is less than 180 metres or less than 25 metres below any aquifer that is a source of usable water, the casing string next to the surface casing must be cemented for its full length. In deep sour gas wells the surface casing may be as deep as 500 metres.

286 Alberta Energy and Utilities Board. 2005. *Bulletin 2005-04: Shallow Well Operations,* http://www.eub.ca/docs/documents/bulletins/Bulletin-2005-04.pdf

Although current regulations require that the casing be cemented to the surface across non-saline groundwater, this was not always the case.[287] In wells drilled and completed under earlier regulations, remedial cementing is mandatory at abandonment if non-saline groundwater is not covered with cemented casing.[288] A company that plans to undertake shallow fracturing must check the cement integrity of all oilfield wells within 200 metres.[289]

4.3 Well stimulation

After a well has been perforated, the gas may flow to the wellbore under its own pressure but, depending on the porosity and permeability of the formation, the well may need stimulation to allow the gas to flow more easily from the perforated interval into the wellbore. Hydraulic fracturing is the initiation and propagation of a fracture (large crack) into the perforated part of the formation by means of hydraulic pressure (see Figure 4-2).[290] The fracturing fluid is the substance used to apply the hydraulic pressure.

[287] Austin, Brenda; Sheila Baron and Stephen Skarstol, 1995. *Groundwater Protection in Wellbores.* p. 7, CADE/CAODC Spring Drilling Conference, April 19-21, Calgary. "Historical cementing practices in many areas of the province of Alberta have left zones containing usable water open to zones containing non-usable water." Thus in wells completed prior to 1992, there may be a route for water with different salinity levels to cross-contaminate. Furthermore, if hydraulic pressures are higher in the shallow aquifers than at deeper levels, fresh water could move downward in the wellbore and cause dewatering of that aquifer. If the pressures are higher in the deeper aquifers, water could migrate up the wellbore, so that more saline water mixes with and contaminates the less saline water in the shallower formation. A modeling study done for wellbores in the Provost area of Alberta indicated that if the shale formations sloughed into the wellbore, the downward rate of water migration would by extremely slow. However, the model showed that, under certain conditions, aquifers would be in open communication above the settled mud solids, with the potential for crossflow contamination. Remedial cementing was carried out to seal off aquifers in the wellbore in the Provost area, but this is often not successful so Alberta Environment "has accepted that usable waters of differing qualities may be left open to one another in Alberta's older wells."

[288] Evidence since 1995 indicates that companies are not finding cross-flows when they squeeze cement into the annulus to abandon older wells in accordance with modern standards. In many cases it is not even possible to squeeze in the cement, since mud has blocked off the annulus. Brenda Austin, Alberta Energy and Utilities Board, personal communication with Mary Griffiths, October 5, 2006.

[289] Alberta Energy and Utilities Board. 2006. *Directive 027: Shallow Fracturing Operations – Interim Controls, Restricted Operations, and Technical Review,* http://www.eub.ca/docs/documents/directives/Directive027.pdf

[290] U.S. Environmental Protection Agency. Undated. *Study Design for Evaluating of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs,* Section 1.2, http://www.epa.gov/safewater/uic/cbmstudy/cbmeth.html

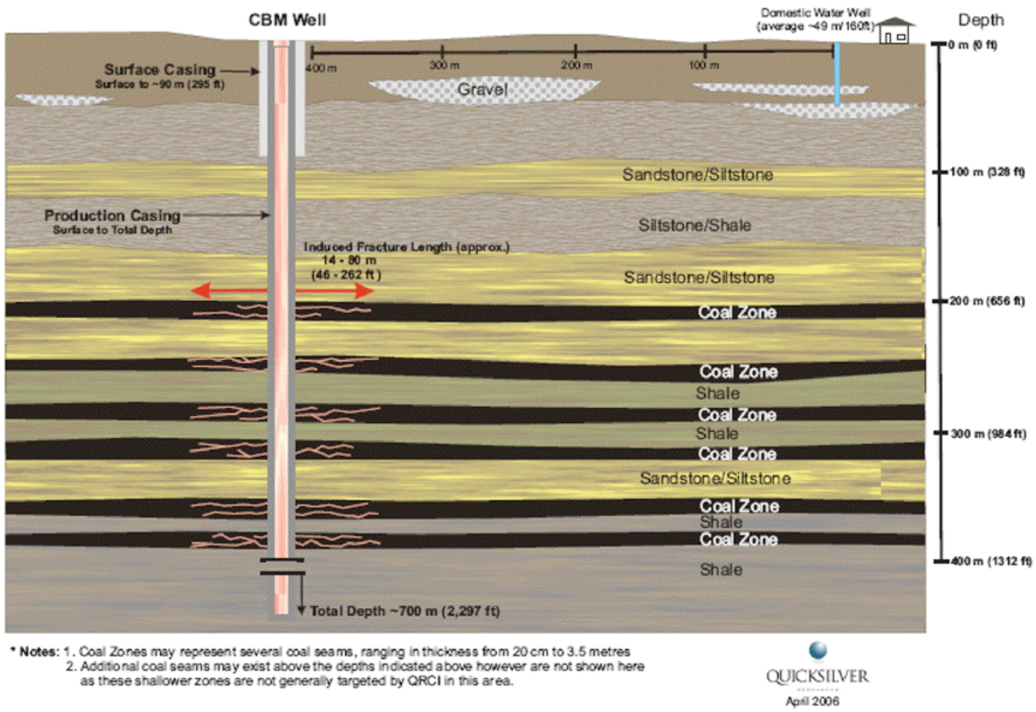

Figure 4-2 Schematic of fracturing in coal seams

Source: Quicksilver Resources Canada Inc.[291]

4.3.1 Fracturing fluids

4.3.1.1 Fracturing fluids in Canada

Here we give an overview of the major fracturing fluids used in Canada and describe some forms of fracturing conducted in Alberta, especially shallow fracturing.

Fracturing fluids may include water, hydrocarbons, gases and acids. These fluids are applied using a wide variety of techniques to hydraulically fracture targeted formations.[292] If water is used, a company will normally obtain it from the local area. Methanol may be used with water to generate a fracturing fluid. These fluids may be used in combination with carbon dioxide or nitrogen to facilitate the treatment and reduce the total amount of fluid (water) needed for the fracture treatment.[293] If the proportion of gas added is less than 55% of the total volume, it is referred to as an energized fracturing system (which is comparable to putting carbon dioxide into soft drinks). If the proportion of gas exceeds 55%, the mixture is a foam (rather like whipping or shaving cream). Gases such as carbon dioxide and nitrogen may also be used alone. In Alberta, the most common fracturing techniques for CBM stimulations, especially in shallow, dry coals is a 100% gas (usually nitrogen) fracture. Water-based fluids are normally used in wet coal

[291] The schematic is based on the Chigwell area in Kneehill County, where the average water well is less than 40 metres deep. Seam thickness and depth will vary in other parts of the Horseshoe Canyon formation.

[292] Halliburton. 2005. *Unconventional Reserves*, A Supplement to E & P, November, http://www.halliburton.com/public/pe/contents/Brochures/Web/H04564.pdf This 20-page brochure provides a good overview of fracturing methods and products used for CBM, shale gas and tight gas.

[293] Halliburton. 2005. "Advanced Frac Fluids, Reliable Tools Help Get Most from Tight Gas Sands", *Unconventional Reserves*, A Supplement to E & P, November, p. 11-13, http://www.halliburton.com/public/pe/contents/Brochures/Web/H04564.pdf

zones.[294] An acid, such as hydrochloric acid, is often used in limestone formations to dissolve some of the rock to increase the number and size of channels for assisting hydrocarbon (gas or oil) to flow to the wellbore.[295]

Proppants, which are solid granular materials such as sand, ceramic beads, glass or plastics, are used to keep the generated fractures open (since much of the fracture fluid is recovered from the stimulated reservoir). Gelled fluids are more efficient at transporting the proppant than straight base fluids (water). The gelling agent is usually an organic substance such as guar (which is derived from a bean and is also used in the food industry). This guar is mixed or slurried with water to generate a thick gelatin-like mixture that supports the added proppant. Once the stimulation is complete the gelled fluid needs to be broken (ungelled) or returned back to a thin watery fluid so it can be recovered from the stimulated reservoir. To do this, a breaker, usually an enzyme, is pumped with the fracture fluid.

As noted above, in Alberta, where CBM is found in dry coals, such as in the Horseshoe Canyon Formation, the seams are fractured using nitrogen.[296] Gaseous nitrogen is usually injected through continuous coil tubing into a number of seams. Once the fracturing is complete the gas is flowed back and released to the air.[297] Chemicals or additives are not normally used with nitrogen fracturing,[298] although other methods may be used in low permeability seams.[299] In the Ardley formation, which may be dry or contain fresh or saline water, various fracturing fluids have been tried.

In southern Alberta, companies use water-based fracturing fluids for fracturing shallow conventional gas wells. The complete fracture fluid, though water-based, will have other additives mixed in; these can include guar or guar derivatives, synthetic polymers, surfactants, gases (nitrogen or carbon dioxide), clay stabilizers and enzymes. Other substances (alcohol, biocide) may be used when needed due to specific conditions.[300]

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[294] In comparison, water-based fracturing fluids predominate for CBM fracturing operations in the U.S.

[295] Centre for Energy. *Natural Gas: Overview; Completing a Well,* http://www.centreforenergy.com/silos/ong/ET-ONG.asp N.B. When an acid is used it reacts with the calcium in a limestone or sandstone formation and is "spent", leaving primarily a calcium chloride brine (which is what is used on roads to melt ice) in the formation.

[296] Horseshoe Canyon CBM wells typically required 3-5 trucks carrying nitrogen. See Canadian Society for Unconventional Gas. 2006. Untitled document giving responses to questions asked at Alberta Environment public information sessions on CBM,. http://www.waterforlife.gov.ab.ca/coal/docs/Canadian_Society_for_Unconventional_Gas.pdf See also http://www.waterforlife.gov.ab.ca/coal/index.html

See also U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs,* p. 4-5, http://www.epa.gov/safewater/uic/cbmstudy.html The EPA report refers to the use of foams for fracturing, with nitrogen or carbon dioxide gas being the most common gases to create the bubbles in the foam. The report notes that foaming agents can contain various additives (such as diethanolamine and alcohols, e.g., isopropanol, ethanol, 2-butoxyethanol) as well as hazardous substances such as glycol ethers. They point out that one of the foaming agent products can cause negative liver and kidney effects, although the actual component causing these effects is not specified on the manufacturer's data sheets. Foaming agents may also be used with gelled fluids.

[297] The atmosphere contains approximately 78% nitrogen and 21% oxygen, so the release of additional nitrogen is not an issue. However, the release of methane to the atmosphere should be avoided as it is a powerful greenhouse gas.

[298] Dawson, Mike. 2006. *Shallow Coalbed Methane Development in Alberta.* Presentation in Nanton for Canadian Society of Unconventional Gas, January 20, http://www.csug.ca/pres/CSUG%20060309%20Nanton.pdf

[299] Hoch, Ottmar. 2006. *Latest Techniques and Technologies for Improving CBM Well Productivity.* The Canadian Institute, 5th Annual Coalbed Methane Symposium, June 19-20, Calgary. Fracturing stimulation in the Ardley have been conducted with nitrogen, nitrogen foams and low-polymer borate gel.

[300] Fulton, Clyde. 2006. *Recycling Blowback from Fracture Stimulation of Shallow Gas Wells,* Petroleum Technology Alliance Canada Water and Innovation in the Oil Patch Conference, June 21-22, Calgary, http://www.ptac.org/env/dl/envf0602p07.pdf EnCana indicates that typical additives used in their shallow gas operations in southern Alberta include guar gum, enzyme breakers, clay control and buffers (to prevent the

The EUB prohibits the use of any toxic substances for fracturing above the base of groundwater protection.[301] The board does not define what is meant by toxic, because toxicity is a function of dosage.[302, 303] A company would normally use a gas- or water-based fracture system when fracturing at shallow depths, but companies are not required to fully disclose the substances used in fracturing, so neither the EUB nor Alberta Environment can scrutinize the list of substances in advance.

Environment Canada is reviewing thousands of substances, and information on the potential effects of specific ingredients in a fracturing fluid may be found on its website.[304] During the initial categorization process Environment Canada determined which substances meet certain ecological criteria (such as persistence and bioaccumulation, toxicity to aquatic organisms and potential for human exposure). The list includes a variety of substances that may be found in fracturing fluids (or drilling muds) including emulsifiers, foaming agents, polymers, gels and surfactants.[305] It has not assessed them specifically in relation to their use for fracturing geological formations or in drilling muds. To use this information, it would be necessary to know all the constituents in fracturing fluids and the way in which different substances react together. It seems that this is not being done in Canada. Service companies are unlikely to reveal all the details of how constituents in fracturing fluids are blended, since they regard this as proprietary information that might give them a competitive advantage. It should, however, be possible to find out the basic constituents since the government requires the MSDS to accompany the chemicals when they are transported and on site during treatment. As with drilling muds (section 4.2.1) it must be remembered that the MSDS refer to the concentrated chemicals, which become diluted in use and further diluted in groundwater.[306]

The *Canadian Drinking Water Quality Guidelines* set limits for some substances that might be contaminants in water, but they do not cover the wide range of substances that might be found in fracturing fluids. Even in their diluted form such substances should not be allowed to

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swelling of clays) and buffers to control the pH of the fracturing fluid. EnCana. 2005. *Recycling Frac Fluid Pilot.* Petroleum Technology Alliance Canada 2005 Water Efficiency and Innovation Forum, June 23, Calgary, *http://www.ptac.org/env/dl/envf0502p07.pdf*

[301] Alberta Energy and Utilities Board. 2006. *Directive 027: Shallow Fracturing Operations – Interim Controls, Restricted Operations, and Technical Review*, p.2, *http://www.eub.ca/docs/documents/directives/Directive027.pdf* The EUB does not specify what it considers to be toxic, since toxicity is a function of dosage. Companies need to assure themselves that the volume of additives they are using to control mud viscosity, etc. are not impacting groundwater. The calculation will be specific to the mud volume, depth of well and area of the province. N.B. If viscosity is not controlled, there is a risk of lost circulation, stuck pipe, etc.

[302] Paraclesus, a famous 15th century Swiss physician and one of the founders of modern medicine said that “The dose makes the poison”. Rachel’s Environment and Health News. 2002. “Paraclesus Revisited”, #754, October 17, *http://www.safe2use.com/ca-ipm/02-12-18h.htm* However, it is also important to remember that some individuals are more susceptible than others.

[303] Alberta Energy and Utilities Board. 2006. *Directive 027: Shallow Fracturing Operations – Interim Controls, Restricted Operations, and Technical Review*, p.2, *http://www.eub.ca/docs/documents/directives/Directive027.pdf* N.B. One common way to determine the toxicity of a substance is to conduct a Microtox test. Certain bacteria are put into a substance and the laboratory measures the proportion that die within a given period of time (e.g., 15 minutes). However, the value of the test is limited when used on viscous fluids, such as fracturing fluids and hydrocarbons, as even non-toxic substances such as guar or mineral oil fail the Microtox test. A complex fluid like coffee, presumably fit for human consumption fails Microtox tests even when diluted with water. Industry expert, personal communication with Mary Griffiths, January 29, 2006.

[304] Environment Canada. Last reviewed 2004. *Substances List*, *http://www.ec.gc.ca/substances/nsb/eng/lists_e.shtml*

[305] Mary Ellen Perkin, Domestic Substances List Surveys Coordinator, Environment Canada, personal communication with Mary Griffiths, September 25, 2006. Any new substances that are not on the current Domestic Substances List, but which may be proposed for use in drilling muds or fracturing fluids, are assessed by the New Substances Division.

[306] For information on Workplace Health and Safety Materials Safety Data Sheets, see Work Safe Alberta, *http://www.hre.gov.ab.ca/whs/network/hstopics/whmis/index.asp*; also Canadian Centre for Occupational Health and Safety, *http://www.oshforeveryone.org/ntnu/external/www.ccohs.ca/*

contaminate drinking water but it is unlikely that there are any routine tests for them.[307] While it might be a good idea to extend the *Canadian Drinking Water Quality Guidelines* to include substances used for shallow fracturing, it would not be feasible to examine domestic water wells for a much wider range of chemicals due to the costs involved and the uncertainty about which substances might be found. Thus, it is essential to ensure that fracturing fluids have no chance of contaminating shallow aquifers.

In addition to nitrogen and carbon dioxide, other less harmful alternatives are being developed for use as fracturing fluids. For example, diesel gel slurries, which are sometimes used in deeper formations, are being replaced by biodegradable mineral oil slurries. Some companies have developed special fracturing fluids for use under the oceans that do not damage marine life.[308] Similar low-toxicity substances might be suitable for use in shallow formations under the land surface. One company is developing new well-drilling technology, which it claims will reduce formation damage in shallow wells and could remove the need for fracture stimulation.[309]

4.3.1.2 Fracturing CBM in the U.S.

The substances used for fracturing in Canada may be similar to those used in the U.S., but environmental laws are significantly different in the two countries, with the Canadian laws being generally more stringent. Also, some fracture techniques used in the U.S. are not appropriate here, due to the nature of the formation or the different climatic conditions.[310] For example, in Canada, the most common fracturing technique for CBM stimulations is a 100% gas fracture, but in the U.S. water-based fracturing fluids predominate in CBM fracturing operations. These differences should be remembered when reading about operations in the U.S.

In the U.S., citizens from seven states in which CBM development is concentrated expressed concern that substances used in fracturing could have impacted shallow aquifers that supply drinking water.[311] Following a court case in Alabama, which found that fracturing had contaminated a residential water well, the Environmental Protection Agency (EPA) decided to evaluate the potential threat. It identified two ways in which fracturing fluids might contaminate aquifers:

1. Direct injection of fracturing fluids into an underground source of drinking water (USDW) in which the coal is located, or injection of fracturing fluids into a coal seam

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[307] Acceptable quantities of substances in drinking water are set out in the *Canadian Drinking Water Quality Guidelines*, *http://www.hc-sc.gc.ca/ewh-semt/pubs/water-eau/doc_sup-appui/sum_guide-res_recom/index_e.html* Under the *Water Act, Potable Water Regulation*, section 6 operators of municipal water works are required to monitor for substances that have the potential to contaminate the supply of raw water, as listed in the *Canadian Drinking Water Quality Guidelines.* However, it is unlikely that substances used in fracturing fluids are included in this list.

[308] Sumi, Lisa. 2005. *Our Drinking Water at Risk: What EPA and the Oil and Gas Industry Don't Want Us to Know about Hydraulic Fracturing,* Oil and Gas Accountability Project, p. 53-56, *http://www.earthworksaction.org/publications.cfm?pubiD=90* Schlumerger has produced a "Green Slurry" system for use in sensitive marine environments, *http://www.slb.com/content/services/stimulation/fracturing/greenslurry.asp*? BJ Services Company produce Cl – 27, which is used in marine environments, is described as "a 'greener' (environmentally friendly) acid inhibitor" in the company's product information sheet.

[309] Scotia Capital. 2006. *Daily Edge,* "Nabors Looking to Run with New Technology", September 15. The new process is Reverse Circulation Centre Discharge.

[310] In the U.S. water without any additives is sometimes used to clean out wells and improve gas flow. For example, in Montana, treated municipal water or untreated produced water is sometimes used to clean cleats in CBM wells. Personal communication between Mary Griffiths and a staff person from the Montana Board of Oil and Gas Conservation, September, 2006. However, straight water has not worked as a stimulation fluid in shallow coals in Alberta. Industry expert, personal communication with Mary Griffiths, January 15, 2007.

[311] U.S. Environmental Protection Agency. Undated. *Study Design for Evaluating of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* Section 1.2, *http://www.epa.gov/safewater/uic/cbmstudy/cbmeth.html*

that is already in hydraulic communication with a USDW (e.g., through a natural fracture system).

2. Creation of a hydraulic connection between the coalbed formation and an adjacent USDW.[312]

In the U.S., a USDW is broadly defined as an aquifer that supplies or has sufficient water to supply a public water system and contains water with less than 10,000 mg/l TDS.[313] This recognizes the fact that may be necessary to desalinize water for use in the future and this water should be protected from contamination. The EPA reviewed public literature and reported groundwater contamination incidents and also conducted field visits in three states. It found that "Most of the literature pertaining to fracturing fluids relates to the fluids' operational efficiency rather than their potential environmental or human health impacts. There is very little documented research on the environmental impacts that result from the injection and migration of these fluids into subsurface formations, soils, and USDWs."[314]

The EPA study looked at different substances and fluids that may be used at different stages in the fracturing process. It examined various additives such as biocides, acids, diesel fuel, solvents and surfactants.[315] Biocides (which are used when the source water is biologically active, i.e., slough, pond water) are used to prevent the growth of bacteria. Acids, such as hydrochloric acid, are very corrosive and will corrode steel piping, so when acids are pumped they usually contain an acid corrosion inhibitor. The report's authors note that the substances are diluted before use. For example, both acids and acid corrosion inhibitors are quite hazardous in their concentrated form, but they are usually diluted on a 1:1,000 ratio and very small quantities are used in U.S. CBM fracturing. They also point out that after fracturing the fluids are pumped back to the surface, sometimes for reuse, which minimizes the possibility that chemicals included in the fracturing fluids would adversely affect shallow groundwater.[316] However, according to studies reported in the original draft of the EPA report, less than half the fracturing fluid may flow back to the wellbore.[317]

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[312] U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs,* p.1-1, *http://www.epa.gov/safewater/uic/cbmstudy.html* The Executive Summary is available at *http://www.epa.gov/safewater/uic/cbmstudy/pdfs/completestudy/es_6-8-04.pdf*

[313] U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs,* p.1-4, *http://www.epa.gov/safewater/uic/cbmstudy.html* This reference gives the full details on the definition of a underground source of drinking water (USDW). Note that the U.S. protects aquifers in USDWs to a much higher salinity level than Alberta (where Alberta Environment protects water up to 4,000 mg/l total dissolved solids (TDS).

[314] U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs,* p. 4-1, *http://www.epa.gov/safewater/uic/cbmstudy.html*

[315] Harmful substances, such as hydrochloric acid and water mixed with a solvent (slick water) were being used in some areas designated as underground sources of drinking water, e.g., the San Juan Basin, New Mexico. U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs, Chapter 5, http://www.epa.gov/safewater/uic/cbmstudy.html*

[316] Not all the fracturing fluids will be recovered and not all the substances in the fluid may return. The actual volume that flows back will vary considerably, depending on the formation. Some of the gel in a fluid may be left in the formation and it may later be mobilized by flowing groundwater. When BTEX is used, 20-30% might remain in the formation, posing a risk if it migrates into shallow groundwater. U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs* p. 4-15, *http://www.epa.gov/safewater/uic/cbmstudy.html*

[317] Sumi, Lisa. 2005. *Our Drinking Water at Risk: What EPA and the Oil and Gas Industry Don't Want Us to Know about Hydraulic Fracturing,* p. 23, footnote 91 Oil and Gas Accountability Project, *http://www.earthworksaction.org/publications.cfm?pubiD=90*

The hazards and toxicological information on undiluted chemicals found in hydraulic fracturing fluids used in the U.S. are summarized in the EPA report,[318] but it does not identify the potentially hazardous level if substances get into water for human consumption. One outcome of the study is that in December 2003 the three largest fracturing companies in the U.S. signed a voluntary agreement with the EPA not to use diesel fuel in hydraulic fracturing fluids in CBM wells in USDWs.[319]

The EPA looked at complaints about possible contamination of aquifers as a result of fracturing CBM formations. Although the EPA focused on complaints relating to fracturing it noted that in some cases complaints resulted from the surface discharge of fracturing fluids, poorly sealed or installed production wells or improperly abandoned wells. The study "did not find confirmed evidence that drinking water wells have been contaminated by hydraulic fracturing fluid injection into coalbed methane wells."[320] Furthermore, "EPA sees no conclusive evidence that water quality degradation in USDWs is a direct result of injection of hydraulic fracturing fluids into coalbed methane wells and subsequent underground movement of these fluids."[321] Yet it did find that in two of 11 CBM basins that it examined, fracturing may have increased communication between coal seams and adjacent USDWs, or have the potential to do so.[322]

The EPA study has been strongly criticized by the Oil and Gas Accountability Project (OGAP), a non-governmental organization based in Colorado.[323] It issued its own report, pointing out, for example, that some information on the potential health effects of various chemicals in the EPA's draft report was eliminated in the final report.[324] Also noted is that the concentration of benzene and eight other chemicals exceeds the acceptable concentration in drinking water when they are injected, sometimes by a huge amount, but that no figures are given on the amounts that actually remain in the formation following fracturing. The OGAP report identifies large gaps in the

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[318] U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs*, Table 4-1, p. 4-9 and 4-10, *http://www.epa.gov/safewater/uic/cbmstudy.html* The information in the report is based on Material Safety Data Sheets. Information on MSDS in Canada is available from Health Canada through the Workplace Health Materials Information System at *http://www.hc-sc.gc.ca/ewh-semt/occup-travail/whmis-simdut/application/msds-fiches_signaletiques_e.html#1* However, this system is set up to protect those working with the substances and does not deal specifically with the substances in water. Acceptable quantities for a range of chemical substances that might find their way in to groundwater are set out in the *Canadian Drinking Water Quality Guidelines*, which include values for a range of chemical substances, *http://www.hc-sc.gc.ca/ewh-semt/pubs/water-eau/doc_sup-appui/sum_guide-res_recom/index_e.html*

[319] U.S. Environmental Protection Agency. 2003. *Elimination of Diesel Fuel in Hydraulic Fracturing Fluids Injected into Underground Sources of Drinking Water During Hydraulic Fracturing of Coalbed Methane Wells*, Memorandum of Agreement Between the United States Environmental Protection Agency and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation. *http://www.halliburton.com/public/pubsdata/hse/pdf/moa_dec12_Final.pdf* These three companies are responsible for a large majority of all fracturing in the U.S.

[320] U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs*, p. 7-6, *http://www.epa.gov/safewater/uic/cbmstudy.html*

[321] U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs*, p. 7-2, *http://www.epa.gov/safewater/uic/cbmstudy.html*

[322] U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs*, p. 5-14, *http://www.epa.gov/safewater/uic/cbmstudy.html*

[323] Sumi, Lisa. 2005. *Our Drinking Water at Risk: What EPA and the Oil and Gas Industry Don't Want Us to Know about Hydraulic Fracturing.*, Oil and Gas Accountability Project, *http://www.earthworksaction.org/publications.cfm?pubiD=90* See also *EPA Whistleblower, Experts Issue Warning on Hydraulic Fracturing*, Press release, April 13, 2005, *http://www.mineralpolicy.org/PR_OGAP_FracReport.cfm*

[324] Sumi, Lisa. 2005. *Our Drinking Water at Risk: What EPA and the Oil and Gas Industry Don't Want Us to Know about Hydraulic Fracturing.*, Oil and Gas Accountability Project, p.vii, *http://www.earthworksaction.org/publications.cfm?pubiD=90* The OGAP report says "The draft EPA study included calculations showing that even when diluted with water at least nine hydraulic fracturing chemicals may be injected into USDWs at concentrations that pose a threat to human health." Benzene at the point of injection is at a concentration 63 times the maximum allowable in drinking water, while the concentration of other substances varies from four to almost 13,000 times that permitted. They also note that when there are complaints, the investigating agencies do not know what chemicals have been used in fracturing operations

scientific data used by the EPA, particularly the lack of information on the health effects of many chemicals used.[325] The report also points out that, when there are complaints, the investigating agencies do not know what chemicals have been used in fracturing operations, since companies are not required to disclose this information. As a result, tests on chemicals in water wells are not conducted for all the chemicals found in fracturing fluids. A number of groups in Colorado have requested the disclosure of information on all chemicals used in oil and gas development,[326] and one group has been compiling its own assessment.[327]

4.3.2 Fracture propagation in shallow formations

Hydraulic fracturing has been used for many years and the industry has a lot of experience and understanding of how the fractures extend through deeper formations. The extent of fracturing in a rock depends on the injection pressures, the rate of the fracturing treatment and the volume of the fracturing fluid injected. It will also depend on the mechanical properties of the rock being fractured, including natural stresses, pore pressure and permeability. Different techniques may be used at different depths.[328]

Basic rock mechanical property theory[329] and practical experience shows that at greater depths a fracture tends to extend mainly vertically but in shallower formations weaknesses with the rock (natural fractures, faults and bedding planes) are more evident and influence the way fractures extend. At shallower depths (e.g., less than 400 to 600 metres in Alberta) fractures extend mainly horizontally with minimal growth in the vertical plane.[330] For example, "… results to date show the vertical and horizontal propagation is limited to 15m and 130m respectively during coal seam fracturing."[331]

A variety of methods are used to gauge the extent of fractures.[332] Some methods are better for estimating fracture depths, while others are better for estimating the horizontal extent of

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[325] A list of data gaps and a critical examination of some gaps is given in chapter 5 of the OGAP report.

[326] Letter from the Oil and Gas Accountability Project to the Colorado Oil and Gas Commission and others, June 14, 2006. The letter asks for the disclosure of the complete make-up and volume of chemicals used in all phases of oil and gas development and requests monitoring for levels and effects where potentially toxic chemicals are used. It explains the request is based on the effects of many of the substances being used in Colorado, which have been identified by the Endocrine Disruption Exchange Inc., and the fact that some of these substances have been released into the air, land and water, e.g., as a result of spills. An attachment to the letter, compiled by the Endocrine Disruption Exchange Inc., outlines potential health effects of chemicals used in natural gas development. Online at http://www.earthworksaction.org/pubs/COGCC-CDPHE_Letter.pdf Earlier, the Natural Resources Defense Council had unsuccessfully asked the U.S. Senate for the regulation of fracturing under the *Safe Water Drinking Act.* Natural Resources Defense Council. 2002. http://www.earthworksaction.org/pubs/200201_NRDC_HydrFrac_CBM.pdf

[327] The Endocrine Disruption Exchange, Inc. 2007. *Chemicals Used in Natural Gas Development and Delivery,* http://www.endocrinedisruption.org/resources/chemicals_used_in_natural_gas_development This document is also online at http://www.earthworksaction.org/publications.cfm?pubID=162

[328] Schlumberger. 2005. *Shale Gas: When Your Gas Reservoir is Unconventional So Is Our Solution,* p. 4. White Paper. In deeper high-pressure shales, slickwater (a low-viscosity, water-based fluid) and proppant are used. In shallower shales, nitrogen-foam fracturing fluids are often used. In deep formations, under high pressures, shale may fracture for up to 900 metres from the wellbore.

[329] Fractures propagate perpendicular to the minimum principle stress of the basin. At depth, the minimum principle stress is in the horizontal plane; therefore fractures are vertical. At shallow depths the minimum principle stress is vertical (the weight of overburden), therefore the fractures are horizontal.

[330] The depth at which fractures propagate horizontally depends on geology and is a result of the stress from the horizontal load from mountain building versus the vertical load from the amount of rock above the target zone. Six hundred feet is a typical depth in Alberta for the transition to horizontal fracturing. Cam Cline, EnCana, personal communication with Mary Griffiths, October 27, 2006.

[331] Canadian Society for Unconventional Gas. 2006. Untitled document giving responses to questions asked at Alberta Environment public information sessions on CBM, http://www.waterforlife.gov.ab.ca/coal/docs/Canadian_Society_for_Unconventional_Gas.pdf See also http://www.waterforlife.gov.ab.ca/coal/index.html

[332] Methods include microseismic mapping , borehole logging and radioactive tracers. Tiltmeters can be used in the wellbore or on the surface to measure the amount and extent of the deformation caused by a fracture.

fractures,[333] but each method has limitations and companies are still learning about shallow fracturing.[334] At the present time it is possible to definitively measure fracture azimuth (that is, compass direction), whether the fracture is vertical or horizontal (or a combination of the two), half-length and height.[335] For example, vertical fracture growth can be measured by observing if the fracture fluid comes back through the upper open perforations in the casing. Horizontal propagation can be measured via tiltmeters. However, the number of fractures analyzed in shallow formations is far fewer than at depth.

Industry will do its best to ensure that fractures do not penetrate adjacent aquifers, not only to protect water resources but because water entering a formation will greatly increase the costs of pumping or even terminate gas production.[336] Companies develop models to try to predict where fractures will go so they can optimize production, but "Fracture modeling alone is not sufficient."[337] An industry expert recognizes that at present "There is no proven, calibrated, practical model or numerical simulator with a history of successful predictability for this class of shallow CBM, shale gas and tight sand fracturing."[338] He also points out that "We do not have a robust design process to confidently predict the size, shape and growth rate of the stimulated zone as a function of pressure, injection rate and time."[339] Fracture mapping, to show the extent and direction of fractures, has been recommended as a way to understand how to optimize fracturing in CBM, but is very expensive.[340] A research project to obtain a better understanding of shallow fracturing is in progress with the first phase due to be completed by September 2007.[341]

The extent of fractures varies with the geology, formation depth and actual fracturing techniques.[342] Occasionally it is possible to find exactly where a fracture extended when a coal

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[333] For example, surface tiltmeters are best for determining fracture orientation and approximate size, while downhole tiltmeters placed in vertical wells at depths near the location of the fracture to be treated are most useful for determining fracture height. U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs,* p. A-19, *http://www.epa.gov/safewater/uic/cbmstudy.html* See also page A-21, Table 6: Limitations of Fracture Diagnostic Techniques.

[334] Gusak, Ron. 2006. Pinnacle Technologies. *Optimization of Hydraulic Fractures in Shallow Gas Using Fracture Mapping Technology,* Petroleum Technology Alliance Canada Shallow Gas Production Technology Forum, March 15. Slide 4 says: "We know everything we need to know about a fracture except … horizontal fractures, out-of-zone growth, upward fracture growth …" The presentation showed how mapping could be improved

[335] Ron Gusak, Pinnacle Technologies, personal communication with Mary Griffiths, January 19, 2007.

[336] For example, one Alberta landowner reported a case where 85 m^3 of water disappeared into an underlying sandstone formation during CBM fracturing. As the sandstone had many times the capacity of the coal, it appeared that the water was being "vacuumed away".

[337] Cipolla, Craig. Pinnacle Technologies. 2005 – 2006. *The Truth About Hydraulic Fracturing – It's More Complicated Than We Would Like to Admit,* SPE Distinguished Lecture Series, *http://www.spe.org/specma/binary/files/5384713Cipolla_DL.pdf* All lectures in the series for 2005-2006 are online at *http://www.spe.org/spe/jsp/basic/0,,1104_1579_5381911,00.html*

[338] McClellan, Pat, Advanced Geotechnology Inc. 2006. *Understanding and Modeling Hydraulic Fracturing at Shallow Depth: A Joint-Industry Project.* slide 4. Petroleum Technology Alliance Canada Water Innovation in the Oil Patch Conference, *http://www.ptac.org/env/dl/envf0602p12.pdf*

[339] McClellan, Pat, Advanced Geotechnology Inc. 2006. *Understanding and Modeling Hydraulic Fracturing at Shallow Depth: A Joint-Industry Project.* slide 4. Petroleum Technology Alliance Canada Water Innovation in the Oil Patch Conference, *http://www.ptac.org/env/dl/envf0602p12.pdf*

[340] Hoch, Ottmar. 2006. *Latest Techniques and Technologies for Improving CBM Well Productivity.* The Canadian Institute, 5th Annual Coalbed Methane Symposium, June 19-20, Calgary.

[341] McClellan, Pat, Advanced Geotechnology Inc. 2006. *Understanding and Modeling Hydraulic Fracturing at Shallow Depth: A Joint-Industry Project.* slide 12. Petroleum Technology Alliance Canada Water Innovation in the Oil Patch Conference, *http://www.ptac.org/env/dl/envf0602p12.pdf*

[342] In the Central Appalachians it is reported that "typical fractures extend from 300 to 600 feet from the wellbore in either direction, but that fractures have been know to extend from as few as 150 feet to as many as 1,500 feet in length … Since some coalbed methane exploration has moved to shallower seams, the Commonwealth of Virginia has instituted a voluntary program concerning depths at which hydraulic fracturing

seam is later mined. This gives the best evidence of the extent of fractures, although it would be misleading to extrapolate this to other formations with different geological characteristics. An EPA report on hydraulic fracturing in CBM cites studies of mined-out coal seams in which fractures filled with sand proppant were found to extend from less than a metre to more than 160 metres. Extensions of fractures too thin to contain proppant penetrated more than 190 metres.[343] In over half the sites examined in the U.S. the fractures extended into the rock layer overlying the coal, while this occurred in three-quarters of the mined-out sites examined in Australia. In the Horseshoe Canyon and Mannville Formations it is thought that, using current stimulation technology, the height of the hydraulic fractures is normally limited to within one to ten metres above the coal seams, or one to three metres below the seam.[344] Despite the fact that fractures extend beyond the coal, the EPA "does not believe that possible hydraulic connections under these circumstances represent a significant potential threat to USDWs."[345] Although fracturing fluids have left the coals and entered adjacent formations in the U.S. the EPA study only considered water quality and did not examine the potential effect on water flows.[346]

In Canada it is recognized that "Shallow gas resources and their development bring underground drilling and stimulation activities that much closer to the surface. In particular, care needs to be taken in stimulation techniques to ensure no damage to above ground structures, as well as to fresh aquifers used for water supply."[347]

In late 2005 the EUB reported incidents where shallow fracturing operations had impacted nearby oilfield operations. It said the incidents had not affected water wells but noted that the "design of fracture stimulations at shallow depths requires improved engineering design and a greater emphasis on protection of groundwater and offset oilfield wells."[348] Noting a new trend in Alberta to develop shallow gas reservoirs less than 200 metres deep using high rate nitrogen stimulations, the board introduced new interim measures that prohibit a company from fracturing gas reservoirs shallower than 200 metres unless it has fully assessed all potential impacts in advance.[349] A company must, for example, identify the depth of all oilfield and water wells within 200 metres of the proposed gas well and notify landowners with water wells within that distance. No fracturing is allowed within 200 metres if the depth of a water well is within 25 metres of the proposed well fracturing depth. At the same time the EUB set up a Technical

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may be performed." Under that program hydraulic fracturing must be at least 500 feet (152 metres) beneath the deepest water well within 1,500 foot (457 metre) radius of any proposed extraction well (or that distance below the lowest topopgraphic point, whichever is lower). U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs,* p.5-7, http://www.epa.gov/safewater/uic/cbmstudy.html

[343] U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs*, Section 3.4.1, p.3-16, http://www.epa.gov/safewater/uic/cbmstudy.html

[344] David Cox. Trident Exploration Corporation, personal communication with Mary Griffiths, June 2003. This statement refers to the operations conducted by Trident Exploration.

[345] U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs*. Section 3.4.1, p.7-5, http://www.epa.gov/safewater/uic/cbmstudy.html

[346] Sumi, Lisa. 2005. *Our Drinking Water at Risk: What EPA and the Oil and Gas Industry Don't Want Us to Know about Hydraulic Fracturing,* Oil and Gas Accountability Project, p. 36-38, http://www.earthworksaction.org/publications.cfm?pubiD=90

[347] Petroleum Technology Alliance Canada. 2006. *Filling the Gap: Unconventional Gas Technology Roadmap,* p. 41, http://www.ptac.org/cbm/dl/PTAC.UGTR.pdf

[348] Alberta Energy and Utilities Board. 2005. *Bulletin 2005-33: Shallow Fracturing Operations: New Requirements, Restricted Operations, and Technical Review Committee,* http://www.eub.ca/docs/documents/bulletins/bulletin-2005-33.pdf

[349] Alberta Energy and Utilities Board. 2006. *Directive 027: Shallow Fracturing Operations – Interim Controls, Restricted Operations, and Technical Review,* http://www.eub.ca/docs/documents/directives/Directive027.pdf

Review Committee, with representatives from government, industry and the public, to evaluate current industry fracturing practices.

In deeper formations, a zone may be fractured several times and it becomes very difficult or impossible to determine the exact propagation and extent of fractures.[350] However, it is uncommon to fracture shallow zones more than once; since the resource is much smaller at shallow depths, it is usually prohibitive to repetitively stimulate these zones.

> **Fracturing regulations in Alabama**
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> Fracturing regulations in the State of Alabama are of interest. Following a complaint, a court in the state ruled that the fracturing of coalbeds should be regulated as an underground injection activity.[1] This means that the requirements are more stringent than elsewhere in the U.S. Permission is required before coal seams can be fractured and details of the fracturing operation must be provided to the government.[1] No fracturing is permitted at less than 91 metres; at depths between 91 metres and 228 metres a company must identify all water wells within 400 metres. If fracturing is to take place in a USDW-bearing area, the company must provide a statement indicating that the fracturing fluids will not contain concentrations of substances that exceed the maximum contaminant levels set in federal drinking water regulations.

4.3.3 Volume of water used for fracturing

The volume of water used for fracturing may vary widely and is highly dependant on the formation, depth, reservoir temperature and pressure, stimulation fluid selected and many other factors. Fracture stimulations are designed to limit the total fluid used on the treatment, as the more fluid that is used, the higher the costs. In fracturing many formations, e.g., conventional gas, shale and tight gas wells, a company is likely to use an “energized” system (which can halve the water requirement) or foam (which can reduce water use by up to 75%).[351]

The experience of one fracturing company indicates that the average volume of water used to stimulate a shallow conventional well in Alberta is approximately 30 m^3 per fracture stimulation. Over 95% of all natural gas wells use less than 80 m^3 per stimulation treatment.[352] The total volume of water used per well may be higher, since a well may be fractured in multiple zones. For example, in shallow gas wells in southern Alberta the average water use for fracturing is estimated to be 100 to 150 m^3 per well, with typically 20 to 25 m^3 water used per zone. Total water use for fracturing may be an issue in a dry region (see below).[353] As noted earlier, water is not normally used to fracture shallow CBM wells in Alberta.

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[350] The initial fracture will be determined by the pre-existing stress in the rock. If a rock is re-fractured, the orientation and extent of the fracture will depend on both the original stress and the stress that results from the first fracture. Thus it becomes increasingly difficult to predict fracture propagation as the number of repeat fractures increases.

[351] In Alberta, where surface temperatures are well below freezing in winter, water handling is a big issue and water volumes are reduced as much as possible (unlike the southern U.S. where temperature is not an issue).

[352] Industry expert, personal communication with Mary Griffiths, January 15, 2007. For comparison, the average water consumption per household per month in the City of Edmonton is 19 m^3. It has been pointed out to the author that one shallow gas well produces about 200 mcf/d gas per day, which is sufficient to heat over 500 homes for a day (an average Alberta home uses 137 GJ of gas a year or 0.38 mcf/day). See: EPCOR. 2005. *Saving Water*, *http://www.epcor.ca/Customers/HomeSmallBus/Energy+and+Water+Efficiency/Saving+Water/* and ENMAX, *What is Natural Gas*, *http://www.enmax.com/Energy/Energy+Tips+and+Tools/Information+on+the+Energy+industry/What+is+Natural+Gas.htm*

[353] Fulton, Clyde. NewAlta. 2006. *Recycling Blowback from Fracture Stimulation of Shallow Gas Wells*, Petroleum Technology Alliance Canada Water and Innovation in the Oil Patch Conference, June 21-22, Calgary, *http://www.ptac.org/env/dl/envf0602p07.pdf* Approximately one million m^3 of water was used each year for fracturing the 5000 to 7000 wells drilled annually in southeast Alberta and southwest Saskatchewan between 2001 and 2005. This water comes from municipal supplies, irrigation canals or other fresh water bodies. .

It is not possible at the time of writing to indicate what volume of water will be used to fracture the deep Mannville Formation. Each area investigated for Mannville CBM is different and each operator is applying different techniques to produce the natural gas. Unlike the Horsehoe Canyon CBM development, the Mannville Coals are still under exploration and development is limited to a very select area.

Likewise, it is not yet known how much water will be required for fracturing shale formations in Alberta. Deep shales (that is, deeper than approximately 1,500 metres) are being studied and tested but only a few wells have been drilled and very little information is publicly available at this time. These deep shale targets are at relatively high pressures due to their depth. This pressure may allow for similar stimulation treatments as in the U.S., for it is this pressure energy that is needed to push the stimulation fluid back out from the treated interval, thus leaving open passages for the gas to flow. But in Canada, the cold winters make it very difficult to handle large volume water treatments. In contrast, many of the shallow shales do not have high reservoir pressures. Thus they do not contain the energy needed to push large fluid volume stimulation treatments back out once treated. Instead, the fluid remains in the reservoir and blocks the gas from migrating to the wellbore, therefore impeding or eliminating production. Other stimulation techniques will be applied to test this resource, most likely energized or foam systems, which reduce the fluid evolved.[354]

Slickwater fractures are used in the U.S. to fracture low permeability reservoirs; in 2004 these accounted for over 30% of fractures.[355] This type of fracturing often uses large volumes of water, and the large demand for water is encouraging recycling efforts. Oilfield produced water from gas drilling operations can be treated to supply fresh water for fracturing. Recycling can reduce the volume of fresh water required for fracturing (and the volume of produced water sent to disposal wells) by up to 90%.[356]

Although slickwater fracturing is not done in Canada, and the amount of water used in Alberta is less than in parts of the U.S., water recycling is also gaining attention here. Due to concern about water shortages EnCana has used recycled fracturing fluids to replace fresh water in the drilling mud for new wells in southern Alberta.[357] NewAlta tested a pilot project to recycle fracturing fluids and found that by reusing the blowback from a fracture it could reduce water requirements

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[354] Industry expert, personal communication with Mary Griffiths, January 31, 2007.

[355] Schein, Gary. 2004-2005. *The Application and Technology of Slickwater Fracturing.* Society of Petroleum Engineers, Distinguished Lecture Series, *http://www.spe.org/spe/jsp/basic/0,,1104_1579_4288897,00.html*

In the Barnett shale in the Fort Worth region of Texas, for example, a single fracturing job can sometimes consume 1000 to 4,000 m^3 of fresh water. The volumes used for fracturing horizontal wells in the Barnett shale may be between 4,000 and 15,000 m^3. See also Schein, Gary. 2006. *Barnett Shale Completions,* slide 34, The Canadian Institute's 2nd Annual Capturing Opportunities in Canadian Shale Gas Conference, January 31 and February 1, Calgary.

Water that flows back from these treatments is unfit for surface discharge and it may be trucked and pumped down deep disposal wells or temporary pipelines may be used to take it to local storage ponds for reuse. Horner, Pat. 2006. *Adaptation and Decentralization: the Future of Wastewater Recycling in the Barnett Shales.* Petroleum Technology Alliance Canada Water Innovation in the Oil Patch Conference, *http://www.ptac.org/env/dl/envf0602p15.pdf*

[356] Horner, Pat. 2006. Aqua Pure Ventures Inc. *Adaptation and Decentralization: the Future of Wastewater Recycling in the Barnett Shales,* slide 13, Petroleum Technology Alliance Canada Water Innovation in the Oil Patch Conference, *http://www.ptac.org/env/dl/envf0602p15.pdf*

[357] EnCana. 2005. *Recycling Frac Fluid Pilot.* Petroleum Technology Alliance Canada 2005 Water Efficiency and Innovation Forum, June 23, Calgary, *http://www.ptac.org/env/dl/envf0502p07.pdf*

for the next fracturing operation by over 40%.[358] At the time of writing the company is hoping to set up field trials.

Companies are not only starting to recycle water, they may be able to treat and use water that is produced with gas or oil instead of starting with fresh water.[359] Various processes may be used for treating produced water but at present the cost of treating water in Alberta usually exceeds the charge for using water supplied by a municipality.[360] Desalination technologies could treat water with less than 10,000 mg/l TDS, though costs would be double to triple the cost of obtaining drinking water from municipal supplies in Edmonton or Calgary. Residual salts from treatment should usually be re-injected into deep saline formations and not disposed of in landfills, in order to protect shallow aquifers. While the use of saline water is generally preferable to fresh water, if the water needs to be treated a company will usually assess the relative environmental impacts of treatment and waste disposal, including energy consumption. Its decision on whether to use fresh or saline water will probably depend, to some extent, on the local availability of both fresh and saline water.

4.4 Water production with gas

4.4.1 Water production from conventional gas wells

In the early stages of gas production, there is usually sufficient gas velocity to transport water from the formation to the surface, where it can be separated from the gas, but over time the pressure declines and liquids may accumulate at the bottom of the well. This leads to intermittent production because eventually the pressure exerted on the formation by the accumulation of liquid will exceed the reservoir pressure and the well will cease to produce.[361] Thus industry looks for economic methods to dewater gas wells. At the present time a very large number of wells in Western Canada require dewatering and various commercial solutions have been developed. It is uncertain whether there will be any further increase in the number of wells being dewatered.[362] Typically, produced water is taken to a deep disposal well for re-injection.

Historically, production of water with hydrocarbons was not an issue, since gas wells were deep and the water was saline. However, as indicated in section 3.1.2, one consultant thinks that production of non-saline water from shallow formations may be a concern.[363] About 12% of

[358] Fulton, Clyde. NewAlta. 2006. *Recycling Blowback from Fracture Stimulation of Shallow Gas Wells*, Petroleum Technology Alliance Canada Water and Innovation in the Oil Patch Conference, June 21-22, Calgary, *http://www.ptac.org/env/dl/envf0602p07.pdf* It was noted earlier that some of the fracturing fluid remains in the formation, so is not available for recycling and a small volume of water will be lost in the water treatment process.

[359] Leshchyshyn, Tim. BJ Services. 2005. *Produced Formation Water and Recycled Fluids for Propped Fracturing.* Petroleum Technology Alliance Canada 2005 Water Efficiency and Innovation Forum for the Oil Patch, June 23, Calgary, *http://www.ptac.org/env/dl/envf0502p06.pdf*

[360] Hum, Florence, Peter Tsang, Thomas Harding, Apostolos Kantzas. 2005. *Review of Produced Water Recycle and Beneficial Reuse. Institute for Sustainable Energy, Environment and Economy, University of Calgary.* Studies cited in the report (p. 27) show it cost $2.28 to $3.06 /m^3 to desalinize produced water with salinities from 6200 to 8340 mg/l TDS. For comparison, in 2005, it cost approximately $1.20/m^3 for drinking water at a loading point north of the city of Edmonton, while the city of Calgary supplied drinking water to two adjacent municipalities for $0.88/m^3, plus a nominal fixed charge.

[361] Individual reservoirs react differently. For example, shallow gas wells in Southeast Alberta produce very small volumes of water, and have done so for decades.

[362] As the price of gas increases, cost may be less of an issue in determining when to shut in a well because of water, or it may become economic to resume operations in a shut-in well. However, when gas prices rise, it is likely that the cost of energy for pumping will also increase. These costs are probably roughly balanced at the present time, so there may not be much increase in dewatering of conventional gas wells even if gas prices increase. Cam Cline, EnCana, personal communication with Mary Griffiths, 2006.

[363] Peachey, Bruce. New Paradigm Engineering Ltd. 2006. *Water Handling Cost Management Equals Energy Management*, slides 21 and 22. Petroleum Technology Alliance Canada 2006 Water Innovation in the Oil Patch Conference. June 21 – 22, Calgary,

Alberta's gas reserves are from gas pools that are less than 500 metres deep.[364] As gas and, in some cases, water is produced, water from shallower units may flow into a formation to replace what has been produced if a communication path is established, depending on the interplay between the hydrodynamic regime and hydrostratigraphic structure between the shallow aquifer(s) and the producing reservoir. Furthermore, the amount of water that may transfer between the two and the duration of the process both depend on the hydrogeological characteristics of the system. Several geologists and an engineer in water resources have pointed out that any flow, if it happens, will probably be very limited and slow. The downward flow of water from overlying fresh aquifers would be determined mainly by the hydraulic-head[365] differences between the zones and the permeability of the zones overlying the gas-bearing zone. In central Alberta shallow conventional and CBM target horizons are gas-saturated and have sub-normal pressures across large regions.[366] Under these circumstances water is not expected to flow into the pore spaces left by the withdrawal of gas.[367] The discussion shows that sweeping generalizations are not possible and underlines the need to treat this issue on a case-by case basis.

It would be wise to revisit depleted and shut-in shallow gas wells to determine if the gas zones are filling with water and to monitor the rates of replenishment. Where this is occurring, "Water monitoring and forecasting for river basin management plans should make allowance for potential losses of ground or surface water volumes to local gas production, even though there is no mechanism for allocating the water."[368]

When water produced from gas wells is pumped back underground, it is normal to have one central injection well for a number of gas wells. Small volumes of water may be trucked, but larger volumes are often piped. Injection into deep disposal wells is a routine operation, but since produced water is mostly saline and contains a variety of chemicals, the soil will become

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http://www.ptac.org/env/dl/envf0602p08.pdf The infiltration of water could occur as a result of pressure differences. In shallow gas reservoirs, the volume of water required to replace a cubic metre of gas is higher than the volume required at depth. The theoretical capacity of a formation to hold water ranges from 40 m^3 per standard 1,000 m^3 gas at 250 metres depth to 15 m^3/water per 1,000 m^3 of gas at 750 metres, which is the deep end of the shallow gas range. Peachey says that the situation is complex and conditions vary, so to get an accurate estimation of the water repressurization it would be necessary to make a geologic assessment of the degree of isolation of each pool from surrounding formations. He points out that isolated underpressured zones will not stay under-presssured if a fracture or poor well casing opens a water flowpath into them from some other zone. These leaks may be too small to detect over a scale of months in the normal production of a gas well but might be seen after a gas well has been shut in for a few years after production. Bruce Peachey, personal communication with Mary Griffiths, January 10, 2007. It is uncertain whether it will take decades, hundreds or thousands of years or more for the water to recharge, and it will depend on the pool and the formation. "If it is assumed that the WCSB [Western Canada Sedimentary Basin] average water to gas replacement ratio is 10 m^3 of water per 1000 m^3 of gas then almost 2 billion m^3/yr of water will be required to replace annual gas production." Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies Water and the EnergyINet*, p. 24; http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf Peachey notes that Alberta Environment estimates that the total annual groundwater recharge rate, province-wide, is about 15 billion m^3/yr. He is concerned that the available precipitation and snow melt for recharge of aquifers in the Medicine Hat area is limited, so the risk of impacts in this area should be investigated.

[364] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies Water and the EnergyINet*, p. 24. This figure is for the estimated volume of initial gas in place, based on 1999 data.

[365] The hydraulic head is a specific measurement of water pressure that can be used to calculate the hydraulic gradient between two or more points. It indicates the potential for a fluid to flow, if a flow pathway is available.

[366] A large portion of central Alberta is characterized as having an unusual hydrodynamic regime. The shallow conventional and CBM target horizons (in the Scollard, Edmonton and Belly River Groups) are by-and-large gas-saturated and have sub-normal pressures across large regions. In the dry parts of the Horseshoe Canyon Formation, for example, there is no connectivity to water-bearing formations. Under these circumstances inflow of water is not expected.

[367] If there were a flow via a poorly cemented well casing, the actual flow would depend on the difference in hydraulic head between the two zones, the size of the pathway along the defective wellbore and the permeabilities of the pathway, the aquifer and the produced unit. The flow is likely to be small, relative to the overall capacity of an aquifer. Stefan Bachu, personal communication with Mary Griffiths, February 12, 2007.

[368] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet*, p. 25; http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

contaminated if there are leaks. In 2005 there were over 20,000 km of water pipelines associated with oil and gas production in Alberta and 179 failures, which is approximately one leak for every 117 km of pipeline.[369] In total over 13,000 m^3 of produced water was spilled.[370] Companies are required to clean up and remediate the soil after spills, with Alberta Environment and the EUB sharing responsibility for enforcement.[371]

4.4.2 Dewatering of coalbed methane wells

As explained in Section 3.2.1, coal seams may contain water or, in the case of the Horseshoe Canyon Formation, they may be predominantly dry. The impacts of removing water from a coal seam depend on the volume and type of water produced. Saline water, such as that from the deep Mannville group of formations, will usually be piped to injection wells and is unlikely to cause an environmental impact unless there is a pipeline leak or spill. Alberta Environment's regulatory requirements for the removal of fresh water are described in section 3.2.3.2. Given the importance of groundwater to rural Alberta, it is not surprising that many landowners in central Alberta are concerned about the potential effects of CBM on shallow aquifers. They feel that CBM production is evolving faster than the regulatory framework and are especially concerned about the Ardley coal zone, where the coal seams may contain fresh water.[372] Although the Horseshoe Canyon coals are mainly dry, the sandstones between the coals may contain gas and also water.[373]

4.4.3 Dewatering of shale gas wells

If shale formations in Alberta are similar to many of those found in the U.S., they will not require much, if any, dewatering. At the time of writing, it does not seem that any gas is being produced from shallow shales similar to those in the Antrim and New Albany areas in the U.S. that produce water.[374]

4.5 Gas migration

Methane is non-toxic and non-poisonous[375] but it does pose a risk if gas exists naturally or migrates into a water well. Gas cannot explode when it is dissolved in groundwater, but when the

[369] Alberta Energy and Utilities Board. 2006. *ST 99-2006: Provincial Surveillance and Compliance Summary 2005,* p. 76 for the total length of pipeline (20916 km) and p. 81 for the number of failures, *http://www.eub.ca/docs/products/STs/st99_current.pdf*

[370] Alberta Energy and Utilities Board. 2006. *ST 99-2006: Provincial Surveillance and Compliance Summary 2005,* p. 88, *http://www.eub.ca/docs/products/STs/st99_current.pdf*

[371] Alberta Energy and Utilities Board. 1998. *Informational Letter IL98-1: A Memorandum of Understanding between Alberta Environmental Protection and the Alberta Energy and Utilities Board Regarding Coordination of Release Notification Requirements and Subsequent Regulatory Response,* *http://www.eub.ca/portal/server.pt?open=512&objID=232&PageID=0&cached=true&mode=2*

[372] Alberta Environment requires a company to comply with the *Guidelines for Groundwater Diversion for Coalbed Methane/Natural Gas in Coal,* *http://www3.gov.ab.ca/env/water/Legislation/Guidelines/groundwaterdiversionguidelines-methgasnatgasincoal.pdf* These Guidelines also refer to Alberta Environment. 2003. *Groundwater Evaluation Guideline,* *http://environment.gov.ab.ca/info/library/7508.pdf* In 2006 Alberta Environment granted approval for the diversion of up to 2500 m^3 water per year (total) from up to three CBM wells drilled below 400 metres in the Buck Lake area.

[373] Wills, Jamie. Waterline Resources Inc. 2005. *Legislation Respecting Water Diversion for CBM Projects in Alberta and British Columbia,* slide 26. Petroleum Technology Alliance Canada 2005 Water Efficiency and Innovation Forum, June 23, Calgary, *http://www.ptac.org/env/dl/envf0502p13.pdf* .

[374] The shales in Antrim and New Albany extend into southern Ontario. There is potential for shale gas in S. Ontario and Natural Resources Canada started a project in 2006 to evaluate the shales. Steve Grasby, Natural Resources Canada, personal communication with Mary Griffiths, January 10, 2007.

[375] Alberta Environment. Undated. *Water for Life. Methane and Groundwater,* *http://www.waterforlife.gov.ab.ca/coal/docs/Methane_and_groundwater_factsheet.pdf*

gas comes to the surface it may bubble out of the water.[376] Methane is lighter than air and if vented it will normally disperse, but if it is trapped in a well pit or pump house it can be dangerous; mixtures of 5 to 15% methane in air are explosive and can ignite if exposed to an open flame, spark or pilot light.[377] In water the maximum solubility of methane is 28 to 30 mg/l (approximately 3% by weight).[378] It is essential to ensure that any water well is vented to the atmosphere to avoid a buildup of methane, especially as methane in its natural state does not have a smell. The odour associated with commercial natural gas that is piped into homes for domestic use comes from mercaptans, a chemical that has been added to help detect leaks. If gas in water is evident from bubbling water at the tap, the system should be vented to the outside.[379] (See section 6.3 on Water Wells for more information.)

Gas may migrate into an aquifer if well casings are not properly constructed or if a well is not correctly abandoned. This has occurred with CBM wells in parts of the U.S.[380] In Alberta, the EUB has measures in place that are designed to address this issue.

The EUB requires companies to test the surface casing vent of a new well (i.e., the vent between the production casing and the surface casing) to identify any leaks to surface. The vent is in place so that liquids or gases can come up the vent and be identified at surface. This test must be done within 90 days after a well has been drilled, and the vent should be monitored throughout the life

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[376] Methane stays in solution below about 6°C and evolves out of the water at between 6°C and 15°C. Above that temperature methane is a gas and will not stay in solution.

[377] Alberta Agriculture, Food and Rural Development. 2006. *Methane Gas in Well Water,* http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/agdex10840 . See also Alberta Agriculture, Food and Rural Development. 2005. *Coal Bed Methane (CBM) Wells and Water Well Protection,* http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/eng9758

See also: Eltschlager, Kenneth K., Jay W. Hawkins, William C. Ehler, Fred Baldassare. 2001. *Technical Measures for the Investigation and Mitigation of Fugitive Methane Hazards in Areas of Coal Mining,* p. 13. U.S. Department of the Interior, Office of Surface Mining, http://www.osmre.gov/pdf/Methane.pdf)

[378] "Methane gas can be transported by ground water in dissolved or pure gaseous states. Methane in ground water is not explosive; but when water containing dissolved methane comes into contact with air, the methane quickly escapes from the ground water into the atmosphere. If this process occurs in a confined space, then the methane could ignite; or if it is allowed to accumulate, it could explode. Because the solubility of methane in water is between 28 and 30 mg/l (milligrams per liter), well water samples with concentrations of dissolved methane greater than 28 mg/l could liberate potentially explosive or flammable quantities of gas inside the well or in confined spaces in well houses or structures containing wells. Concentrations of methane greater than 10 mg/l but less than 28 mg/l are a possible indication that methane concentrations may be increasing to dangerous levels in ground water (Eltschlager and others, 2001)." U.S. Geological Survey Fact Sheet 2006 – 3011, *Methane in West Virginia Groundwater,* http://pubs.usgs.gov/fs/2006/3011/pdf/Factsheet2006_3011.pdf

[379] Mitigation methods include vented well caps and vent tubes (for enclosed structures). See *Methane Gas in Your Water Well, A Fact Sheet for Domestic Well Owners,* Kentucky Department for Environmental Protection, 2003, http://www.water.ky.gov/NR/rdonlyres/59A7BAE6-29E5-4EB1-841A-307902100F5F/0/GWBwell_and_methane.pdf

[380] Gas migration occurred in the early stages of CBM development in the San Juan Basin in the U.S. up old, poorly cemented wellbores. Oil and gas wells drilled in the 1950s and 1960s had not been cemented to surface, so when the CBM seams were dewatered and the pressure was reduced, the gas was no longer "trapped" in the coal and some gas migrated through old wellbores into shallow groundwater (R. Griebling, Director of the Colorado Oil and Gas Conservation Commission, personal communication with Mary Griffiths, 2003; first cited in the Pembina Institute's 2003 report on Unconventional Gas, in footnote 166). Once this problem was recognized, both Colorado and New Mexico required special testing of the cement casing in conventional gas wells to identify leaks. The U.S. Environmental Protection Agency study on hydraulic fracturing examined water well complaints associated with gas migration in the U.S., including the San Juan Basin. In the Fruitland Formation in the San Juan Basin they concluded that "… there appears to be evidence that methane seeps and methane in shallow geologic strata and water wells may occur because the methane moves through a variety of conduits. These conduits include natural fractures; [and] poorly constructed, sealed, or cemented manmade wells used for various purposes. No reports provide direct information regarding hydraulic fracturing. Methane, fracturing fluid, and water with a naturally high TDS content could possibly move through any of these conduits. In some cases, improperly sealed gas wells have been remediated, resulting in decreased concentrations of methane in drinking water wells." U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs,* Chapter 6, p.6-8, http://www.epa.gov/safewater/uic/cbmstudy/pdfs/completestudy/ch6_6-5-04.pdf In much of Alberta the gas is held in place not by the water pressure but by the overlying impermeable rocks. In these situations, if there were a poorly cemented wellbore it would be a route for gas migration even before the development of CBM. The exception is in parts of the Ardley zone where the gas is held in place by water. The EUB requirements for well abandonment, outlined in the text in section 4.8 below, are designed to prevent gas migration.

of the well. In parts of the province a company must also test for gas migration to the surface.[381] Gas migration occurs when gas migrates up the outside of the surface casing, where this is the easiest path to surface. The literature notes that lateral migration along aquifers is limited to very short distances, usually on the order of tens of metres. The EUB normally requires all non-saline water zones be covered by cement, which is squeezed down the casing and up between the casing and the formation. This method reduces bubbles and channels in the cement. If there is evidence of a surface casing vent flow that has the potential to impact groundwater, remedial action is required. All surface casing vent flows and gas migration issues must be repaired at abandonment, because the surface casing vent can no longer safely channel any leakage to the surface.[382] Gas migration from wells that have not been correctly abandoned, will usually be evident from the poor growth of vegetation around the wellhead.[383]

Gas migration has long been a problem in some parts of Alberta, in particular associated with heavy oil wells in the Lloydminster area (on the Alberta/Saskatchewan border). Leaks were detected through measuring the surface casing vent flow and were also seen by impacts on the vegetation close to the well, as the gas leaked through the soil around the wellhead.[384] Several studies were conducted in the area, including an examination of methane in water wells.[385] Analysis of the isotopic composition of the gas was used to locate its source. In this area it was possible to distinguish between the gases of shallow and deep origin by using the carbon-isotope composition of the methane and also of the non-methane components in the gas (ethane, propane and butane).[386] The composition of the gas from the Colorado shale formation was distinct from the composition of the deeper Mannville gas. The leaking gas matched that from the Colorado shales. The isotopic testing showed that the well casings needed remediation in these shales, where it is often difficult to get a good cement bond between the casing and the formation. Similar analysis was also conducted for leaking wells in Saskatchewan,[387] and in the Cold Lake area.[388] Researchers reported that, “For the first time, the source depth of these gases in the WCSB [Western Canada Sedimentary Basin] can be accurately determined using isotopic fingerprints generated through routine analytical procedures.”[389] However, the techniques are

[381] Alberta Energy and Utilities Board. 2003. *Interim Directive ID 2003-01 1) Isolation Packer Testing, Reporting, and Repair Requirements; 2) Surface Casing Vent Flow/Gas Migration Testing, Reporting, and Repair Requirements; 3) Casing Failure Reporting and Repair Requirements*. Section 2.3.2 states: “Within 90 days of drilling rig release, licensees must test new wells for GM problems in Townships 45-52, Ranges 1-9, West of the 4th Meridian, and Townships 53-62, Ranges 4-17, West of the 4th Meridian.” *http://www.eub.ca/docs/ils/ids/pdf/id2003-01.pdf*

[382] Alberta Energy and Utilities Board. 2004 update. *Directive 20: Well Abandonment Guide*, p. 1, http://www.eub.ca/docs/documents/directives/Directive020.pdf

[383] If gas is migrating into the soil around a wellhead, the company that owns the well must find the source and take measures to correctly abandon the well. The first step will be isotopic analysis of the gas, to identify its source. In some cases the gas may come from deep formations, but it may also have a shallow, biogenic source. Occasionally, biogenic gas has originated from sawdust that soaked up spills around the drilling rig and was then used as fill around the well, outside the cemented casing.

[384] Schmitz, Ron, Husky Oil Operations Ltd., Brian Emo and Dale Van Stempvoort. Undated (c.1995). *Gas Migration Research – Working Toward Risk-Based Management.* Most of the leakage rates into soil were less than 0.1 m^3/day, although higher values were observed.

[385] Canadian Association of Petroleum Producers. 1996. *Migration of Methane into Groundwater from Leaking Production Wells Near Lloydminster; Report for Phase 2.*

[386] Rowe, Devon and Atis Muehlenbachs. 1999. “Low-temperature thermal generation of hydrocarbon gases in shallow shales,” *Nature*, Vol. 398, March 4., p. 61-63.

[387] Szatkowski, Bryan, S. Whittaker and B. Johnston. 2002. “Identifying the Source of Migrating Gases in Surface Casing Vents and Soils Using Stable Carbon Isotopes, Golden Lake Pool, West-central Saskatchewan,” *Summary of Investigation, Saskatchewan Geological Survey*, Volume 1, p. 118-125.

[388] Szatkowski, Bryan, S. Whittaker, B. Johnston, C. Sikstrom and K. Muehlenbachs. 2001. “Identifying the Source of Dissolved Hydrocarbons in Aquifers Using Stable Carbon Isotopes,” *Canadian Geotechnical Conference, Oil Sands Hydrology*, Calgary, Alberta, Sept. 16-19, Paper H307.

[389] Rowe, Devon and Atis Muehlenbachs. 1999. “Low-temperature thermal generation of hydrocarbon gases in shallow shales,” *Nature*, Vol. 398, March 4, p. 63.

still quite new and the characteristics of the different formations are not always as distinct as in the Lloydminster region.[390] In many cases "we need a better understanding of the origin of the gas in the individual formations as well as regional fluid flow to fully utilize isotope geochemistry of natural gas."[391] The complexities relating to the isotopic analysis of gas are examined in more detail in Appendix A.

The EUB found four cases of gas migration into water wells between 1996 and 2001, but has not confirmed any cases since then.[392] All the leaking wells were fixed.[393]

Alberta Environment investigates complaints about domestic water wells. In the period January 2004 to May 2006, the Central Region investigated 125 complaints.[394] It found that over half (73) were related to water well maintenance. Only three cases were related to oil and gas activity and none was due to gas migration.[395] In the southern region over the same period, of the 230 complaints received, 23 were suspected by landowners to be problems related to CBM. In 15 of these cases, investigation revealed that all were related to the maintenance of the water well; the remaining eight cases were still being investigated. The number of water well complaints in the northern region was far lower, and only 21 calls were received over the same period.

Additional information about complaints specifically related to CBM wells is available for the slightly longer period, January 2004 to November 2006. During that time, Alberta Environment received 55 water well complaints that had possible connections to CBM-related activities.[396] Forty-three of the complaints were investigated and closed and showed no linkages to CBM. In November 2006, ten cases were still open and active and two cases had been administratively closed.[397] Thus, at the time of writing, there is no published evidence of gas migration (or other impacts) related to CBM wells in Alberta, but some investigations are taking a long time to complete.[398]

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[390] There are no shallow coals in the Lloydminster area, so it is not possible to correlate isotopic data from the Lloydminster area with the Edmonton/Horseshoe Canyon coals.

[391] Muehlenbachs, Karlis, Bryan Szatkowski and Ryan Miller. 2000. *Carbon Isotope Ratios in Natural Gas: A Detailed Depth Profile in the Grand Prairie region of Alberta.* Geological Association of Canada. Convention in Calgary. The citation is true for CBM regions. Karlis Muehlenbachs, personal communication with Mary Griffiths, July 22, 2006.

[392] Brenda Austin, Alberta Energy and Utilities Board, personal communication with Mary Griffiths, November 2, 2006. For comparison: Alberta Environment's data on water well complaints for 1996-September 2000 show that there were 76 complaints where the owner of the water well thought that reduced yield, water quality change or sediment in water wells was caused by nearby oil or gas activity. In six cases the problem was actually linked to oil and gas development. Alberta Environment, personal communication with Mary Griffiths, 2000 (cited in *When the Oilpatch Comes to Your Backyard*, p. 57).

[393] Brenda Austin, Alberta Energy and Utilities Board, personal communication with Mary Griffiths, January 22, 2007.

[394] Information on water well complaints provided by Alberta Environment to Mary Griffiths, July 4, 2006.

[395] The three cases were related to the "Acclaim" well blow out near Edmonton. .

[396] Alberta Environment provided the following breakdown by region. Southern Region: 29 complaints were received with 22 closed (no CBM linkages) and 7 remain open and active. The 7 open and active incidents are from: Nov. 25, 2005, March 2, 2006 (2 incidents), March 11, 2006, September 13, 2006, September 14, 2006, and November 1, 2006. Two of the complaints relate to wells for which baseline water well testing was conducted. Central Region: 26 complaints received, 21 are closed (no CBM linkages), 2 administratively closed and 3 open and active. The 3 open and active incidents have been open since August 9, 2005, December 20, 2005 and February 17, 2006. Personal communication with Mary Griffiths, March 26, 2007. A map showing the boundaries of the Central and Southern regions is available at *http://www3.gov.ab.ca/env/regions/index.html*

[397] Alberta Environment explains "administratively closed" as follows: these are incident files that have all of the investigative components completed and conclusions made. These include files that are complete and closed but the Department is having trouble contacting one of the parties involved (at times the complainant themselves) or where all work on the incident is completed and communicated to the complainant but the final closure correspondence has just not gone out.

[398] Alberta Environment notes that there is no set time for an investigation to be concluded. Investigative programs relating to gas may include, but are not limited to, water well construction, water distribution system assessment, compositional and isotopic gas characterization, appropriate geologic, hydrogeologic, hydrochemical, and bacteriological investigative components.

Alberta Geological Survey staff searched Alberta Environment's water well database to identify where water drillers reported the occurrence of gas. The location of the wellbores is shown on a map.[399] Gas has been reported in fewer than 1,200 wells distributed across much of Alberta, out of more than 360,000 water wells contained in the database. The dates associated with these well reports shows that the occurrence of gas predated CBM development, and in most cases any type of energy development.[400] It is often not realized that the database used to construct the map contains information on many types of wellbore, not only from bores for the construction of water wells. Many of the wellbores are likely of other types such as coal test holes, structure test holes, oil and gas wells and others, in addition to water wells.[401] After a perfunctory analysis of the wells that reported gas showings, more than 900 water wells were retained, the rest being oil or gas wells also recorded in the EUB database.[402] The reports do not indicate whether the gas found is methane. The source of gas in approximately 400 of these wells seems to be natural. A more detailed, well-by-well analysis is needed to possibly identify the source of gas in the remaining 500 wells, which, nevertheless, constitute less than 0.2% of the water wells in the province. However, it is not know what proportion of water well drillers actually reported gas in water wells in the past. They are still only required to report to Alberta Environment "where gas is found in a quantity that would prevent the safe drilling or operation of the water well."[403]

Gas in water wells may be naturally occurring as a result of shallow coal seams that contain methane, biogenic activity of microbes normally found in groundwater, or shallow gas accumulations.[404] The potential for gas into water has become a concern for people living in areas where CBM is being produced. Over 26,000 water wells have been drilled through or completed in coal seams. Water wells may be completed in coal seams, since they can sometimes provide a useful aquifer. However, if the water pressure in the coal seams falls (which might be due to domestic or industrial water use, drought reducing the recharge, or the removal of water for the extraction of CBM), it is possible that methane will be desorbed from the coal and be free to enter groundwater.

It is recognized that methane migration can occur with or without adjacent gas development activities, but "The regulatory authorities and industry need to develop sustainable regulations and practices that satisfy the legitimate concerns of stakeholders most obviously affected by the

[399] Alberta Environment. 2006. *Methane and Groundwater, p. 3.* Locations where gas was noted during or after drilling, *http://www.waterforlife.gov.ab.ca/coal/docs/Methane_and_groundwater_factsheet.pdf*

[400] Brenda Austin, Alberta Energy and Utilities Board, personal communication with Mary Griffiths, January 22, 2007.

[401] The wellbores examined for the report were not only those drilled for water wells, but may include other types, such as coal test holes, structure test holes, oil and gas wells. There are several limitations on the data provided since it seems that 1) there are no analyses for the gas samples attached to the database; 2) the criteria for defining how a driller would decide if there was gas present are not included with the database; 3) there were sometimes comments on what interval the driller thinks the gas comes from, but not always; and 4) there is not always a mention of how much gas was encountered, and if there is, it is generally qualitative. Tony Lemay, Alberta Geological Survey, personal communication with Mary Griffiths, January 29, 2007.

[402] The Alberta Environment database shows approximately 900 water wells containing gas. (This is a net value after some wells that are related to oil and gas operations have been eliminated.) Approximately 400 of these wells are completed in coal seams or the Milk River Aquifer, which is naturally gassy. The origin of the gas in the other wells is not known. Stefan Bachu, Alberta Geological Survey, personal communication with Mary Griffiths, February 6, 2007.

[403] *Water (Ministerial) Regulation, section 43(3), http://www.qp.gov.ab.ca/documents/Regs/1998_205.cfm?frm_isbn=9780779720699* Section 43 of the regulation also requires notification when the water well driller encounters saline water.

[404] The shallowest gas reservoir recorded in Alberta Energy and Utilities Board's Reserves database is at 36 metres depth in northwestern Alberta. Many shallow gas occurrences in Quaternary clays and tills have been encountered by staff of the Alberta Geological Survey. Stefan Bachu, Alberta Geological Survey, personal communication with Mary Griffiths, February 6 and 13, 2007.

development of unconventional gas."[405] This is because "Recent developments mark the control of any methane migration to well water as the highest priority for those affected."[406]

There is still much to learn. Indeed, "Where we have our biggest lack of information is on groundwater — the extent of aquifers, the quality and variability of the groundwater in these aquifers, the gas content within this groundwater, and the sources of that gas."[407]

Although at the end of 2005 the industry reported that there had been no proven connection between gassy water wells and CBM activity in Alberta,[408] the MAC took public concerns seriously and recommended that Alberta Environment and the EUB work with industry to investigate the potential for methane migration or release to water wells as a result of the depressurization of coal seams.[409]

If gas is found in a water well, it is important to identify its source. Is it migrating from natural gas in an adjacent coal or sandstone zone, or is methane being created by bacteria or other microbes in the aquifer?[410] Various types of information are required to investigate the source of the gas, including geological, hydrogeological and geochemical data as well as the history of CBM production in the area. Isotopic testing (see below) may help identify the source of any migrating gas. The complexity of analysing the source of gas in water wells is shown in a presentation about investigations in the U.S. entitled *What's in Your Water Well?*[411]

In May 2006, Alberta Environment introduced baseline water well testing in regions proposed for shallow CBM wells that are completed above the base of groundwater protection, as described in section 3.2.3.1. Part of the test involves capturing any free gas and measuring its volume and composition. Analysis of the gas composition will show the proportion of methane, nitrogen and carbon dioxide in the gas, and also whether there is any ethane, propane or butane. The isotopic characteristics of the gas must also be analyzed in a portion of the samples. If an aquifer is being contaminated by the migration of gas from below, or by gas being generated by bacteria in the aquifer, it is likely that the aquifer would be supersaturated with gas and the problem gas would be travelling as bubbles (that is, as free, not dissolved gas).[412] It is the free gas that causes the bubbling and frothing at the tap and can be a hazard if trapped in a confined space. If there is free gas in the water, it is important to vent the water well and seek the source

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[405] Petroleum Technology Alliance Canada. 2006. *Filling the Gap: Unconventional Gas Technology Roadmap,* p. 41, section 7.2, http://www.ptac.org/cbm/dl/PTAC.UGTR.pdf

[406] Petroleum Technology Alliance Canada. 2006. *Filling the Gap: Unconventional Gas Technology Roadmap,* p. 42, section 7.4, http://www.ptac.org/cbm/dl/PTAC.UGTR.pdf

[407] Bernhard Mayer, cited in article by Mark Lowey, "CBM fingerprinting project" in *Alberta Oil,* Vol. 2, Issue 2, 2006.

[408] Canadian Society for Unconventional Gas. 2006. *Natural Gas from Coal Development in Alberta,* slide 9, http://www.waterforlife.gov.ab.ca/coal/docs/CSUG_AENV_Master_rev_june12.pdf

[409] Government of Alberta. 2006. *Coalbed Methane/Natural Gas in Coal Multi-Stakeholder Advisory Committee Final Report,* http://www.energy.gov.ab.ca/docs/naturalgas/pdfs/cbm/THE_FINAL_REPORT.pdf Recommendation 3.6.1. Methane Migration and Release.

[410] If a water well is completed in a coal seam, one would expect some methane to be produced with the water, with more methane being produced if the volume of water withdrawn exceeds the rate of recharge, and pressure in the coal decreases.

[411] Gorody, Anthony W. 2005. *What's in Your Water Well?* Presentation at the Northwest Colorado Oil and Gas Forum, November 18,. http://www.oil-gas.state.co.us/Library/library.html or http://www.oil-gas.state.co.us/Library/WHAT%20IS%20IN%20YOUR%20WATER%20WELL.pdf

[412] Karlis Muehlenbachs. University of Alberta, personal communication with Mary Griffiths, July 22, 2006.

of the gas; it is not necessary to know the level of dissolved gas if the problem is already evident.[413]

However, some dissolved gas will also come out of solution when water is drawn from a well and brought to the surface. Methane gas that is dissolved in water will stay in solution at low temperatures (below approximately 4^{o}C), but is gradually given off at higher temperatures (between 6 and 15^{o}C, which is a typical range for the temperature of tap water).[414] The Alberta Environment protocol does not require a test for dissolved gas at the present time. The results from dissolved gas tests are likely to vary because the amount of gas left dissolved in the water depends on a number of factors, including not only the temperature but also atmospheric pressure, the pumping history of a well (which may vary with the seasons), the salt content of the water and the sampling method.[415] Since testing for dissolved gas will identify wells that contain gas, even if the concentrations are not sufficient to produce free gas, it provides a more accurate record of baseline conditions than measuring solely for free gas. At the time of writing, Alberta Environment is investigating whether it is possible to develop sampling techniques and equipment to enable accurate assessment of the volume of dissolved gas in water samples.[416] Dissolved gas is being measured in some research projects in Alberta (see Appendix A) and in studies in the U.S.[417] Measurement of dissolved gas could be done in the same way as in the U.S.[418]

It is important for those with dissolved gas in their wells to understand the significance of changes in the measured values; changes in low concentrations could be due to differences in sampling and other conditions, and only increases above a certain threshold are likely to merit attention. Thus, while very low levels of dissolved gas are not of significance, a level of 10 mg/l

[413] Keech, Donald, K. and Michael S. Gaber, 1982. *Methane in Water Wells*, WWJ, February, p.34. University of Minnesota, http://www.seagrant.umn.edu/groundwater/pdfs/Methane.pdf This article notes that the Michigan Department of Public Health considers less than one percent methane-in-water (by volume) as being safe from explosion hazards, but if levels are higher a methane removal system should be installed on the water supply.

[414] The release of methane gas, from dissolved to free, may be compared with the release of dissolved carbonic acid gas in pop bottles. However, the gas in pop is released much more slowly than methane is released, as it is very soluble. The colder the water, the more methane it will contain. The approximate temperature of groundwater sub surface is 6^{o}C . When the water is brought to the surface, the methane will initially stay in the water, since it is no warmer than it was underground. As it warms up, the methane starts to absolve as a gas from the water, if the water is gas-saturated. If the gas is sub-saturated, it would need to rise several degrees above the underground temperature before it would start to release. Any remaining dissolved methane in water that is not released at atmospheric pressure – that is, when the water comes out of the tap – will be released if the water is boiled.

[415] Keech, Donald, K. and Michael S. Gaber, 1982. *Methane in Water Wells*, WWJ, February, University of Minnesota, http://www.seagrant.umn.edu/groundwater/pdfs/Methane.pdf Values have been converted from Fahrenheit to Celsius.

[416] To get the accurate concentration of dissolved methane it may be necessary to take the sample from the aquifer or "downhole". It also requires a method to determine the influence of other factors on the dissolved gas level (such as temperature, pressure and the recent rate at which water has been withdrawn from the well). This is important, to ensure that samples taken at different times (e.g., before and after the drilling of a CBM well) are truly comparable.

[417] Gorody, Anthony W.; Debbie Baldwin and Cindy Scott. 2005. *Dissolved Methane in Groundwater, San Juan Basin, La Plata County Colorado: Analysis of Data Submitted in Response to COGCC Orders 112-156 & 112-157,* http://ipec.utulsa.edu/Conf2005/Papers/Gorody_DISSOLVED_METHANE_IN_GROUNDWATER.pdf This paper was presented at the 12th Annual International Petroleum Environmental Conference, 2005.

[418] U.S.Geological Survey. 2006. *Dissolved-Gas Concentrations in Ground Water in West Virginia, 1997-2005,* http://pubs.usgs.gov/ds/2005/156/pdf/WV_Data_Series156.pdf This paper describes one method to measure dissolved gas using a system that avoids exposing the groundwater to the atmosphere.

or more could result in lethal concentrations building up in an unventilated space.[419] Thus such levels may trigger further investigations into the source of methane.

Once gas samples are taken, an analysis of the gas can help identify its source. It is important to know not only the characteristics of any gas in a water well, but also the characteristics of gas in coal seams and aquifers. This was recognized by the EUB in 1999 when it noted that the use of stable carbon isotopic ratios is a relatively new technique for the investigation of surface casing vent flows (SCVF) and gas migration (GM) and is still being refined. It reported, "Development and availability of high quality regional databases, containing interpreted analytical and geological information, are necessary prerequisites to defensible, extrapolated diagnoses for SCVF/GM programs."[420] Alberta Environment's baseline water well testing will provide some information on gas in shallow aquifers, but it is also essential to collect and analyze baseline data on the gas in coal seams.

In sum, gas migration is a potential concern with water wells that are close to natural gas development, but gas was found in water wells across the province long before the development of CBM. To enable the source of any problem to be identified, it is important to have baseline information. This includes

1. thorough characterization of produced gases and fluids from CBM wells
2. thorough characterization of groundwater and its gases prior to the commencement of CBM production
3. careful monitoring of groundwater quality during CBM production.[421]

In some cases it will be possible to clearly identify the source of migrating gas, from the proportion of methane, ethane and propane it contains and from the isotopic fingerprints of these gases and, if necessary, the fingerprint of the hydrogen in the water. However, as explained in Appendix A, this is a complex task and it is not always possible to determine the source of gas, even when the gas in a water sample has been analyzed.

4.6 Commingling of gas production

If different zones produce gas, they are often kept separate in the wellbore to prevent cross-flows of gas or groundwater. However, where there are several shallow zones (e.g., several thin coal seams) companies may commingle production. The dry coals in the Horseshoe Canyon and Belly River pools are often interspersed with sandstones containing gas and, while they may not be economic to produce individually, their production will be worthwhile if commingled with the CBM.

Where formation pressures are compatible the production of shale gas is also likely to lead to an increase in commingling. Shale gas production rates may be relatively low and not justify the

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[419] Gorody, Anthony W. 2005. *What's in Your Water Well?* Presentation at the Northwest Colorado Oil and Gas Forum, November 18, slide 23, "Why Monitor Dissolved Methane Concentrations?" *http://www.oil-gas.state.co.us/Library/library.html* or *http://www.oil-gas.state.co.us/Library/WHAT%20IS%20IN%20YOUR%20WATER%20WELL.pdf*

[420] Alberta Energy and Utilities Board 1999. *General Bulletin GB 99-6, Application of Stable Carbon Isotope Ratio Measurements to the Investigation of Gas Migration and Surface Casing Vent Flow Source Detection,* http://www.eub.ca/docs/ils/gbs/pdf/gb99-06.pdf

[421] Mayer, Bernhard, 2006. *Assessment of the Chemical and Isotopic Composition of Gases and Fluids from Shallow Groundwater and from Coalbed Methane Production Wells*, 2006 Water Innovation in the Oil Patch Conference, Petroleum Technology Alliance Canada, June 21-22, Calgary, *http://www.ptac.org/env/dl/envf0602p10.pdf* The paper refers to dissolved gas, as the area to be examined contains little free gas.

cost of a well, but commingling could make it economic. As shale gas deposits are found interbedded with gas-bearing sandstones, limestones, and so on, commingling is very likely.[422]

Commingling can reduce the number of wells required (and reduce surface impacts), but if one or more of the commingled zones is above the base of groundwater protection, there is a risk that shallow groundwater could be affected as a result of cross-flows between formations containing fresh, usable water and saline water or two or more different formations containing fresh water. The EUB does not permit the commingling of gas from wet coals that include the Ardley (Scollard), Mannville and Kootenay with gas from other formations "because of the potential negative impact of water production on CBM recovery and mixing of water between aquifers."[423] Commingling is not permitted in shallow sands either. However, commingling of production from "dry" coals in the Horseshoe Canyon and Belly River formations with other gas formations is becoming fairly common.

In the past, the EUB always required a company to make an application to commingle production anywhere in the province.[424] In 2006 the board decided to allow companies to commingle production from two or more pools in the wellbore in some regions (and under certain circumstances) without making an application to the board.[425] Routine commingling of production from above and below the base of groundwater protection in these regions is permitted only if the total volume of water produced by the gas well is less than 5 m^3/month. A specific application is required if there is a water well within 600 metres and there is less than 25 metres between the bottom of that water well and the closest formation proposed for commingling. As explained in section 3.1.3.1, any company with a gas (or oil) well that is completed above the base of groundwater protection must monitor its water production and immediately report to the board if the well is producing more than 5 m^3/month of water.[426]

In 2006, the Pembina Institute objected to proposals for commingling of gas where one or more zones are above the base of groundwater protection. The EUB limit of 5 m^3/month is an arbitrary value but as there is low potential for cross-flows with very small volumes of water, this should protect fresh water aquifers in most circumstances. However, swift action will be needed to close

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[422] Petroleum Technology Alliance Canada. 2006. *Filling the Gap: Unconventional Gas Technology Roadmap,* p. 6, http://www.ptac.org/cbm/dl/PTAC.UGTR.pdf See also, Alberta Energy and Utilities Board. 2006. *Management of Commingling in the Wellbore, Control Well Requirements Coalbed Methane and Shale Gas,* http://www.eub.ca/portal/server.pt/gateway/PTARGS_0_212_820116_0_0_18/ Page last updated November 3, 2006.

[423] Alberta Energy and Utilities Board. 2006. *ST98-2006: Alberta's Energy Reserves 2005 and Supply/Demand Outlook,* p.4-2, http://www.eub.ca/docs/products/STs/st98_current.pdf

[424] Alberta Energy and Utilities Board. 2005. *Bulletin 2005-04: Shallow Well Operations,* http://www.eub.ca/docs/documents/bulletins/Bulletin-2005-04.pdf

[425] Alberta Energy and Utilities Board. 2006. *Bulletin 2006-28: Changes to the Management of Commingling of Production from Two or More Pools in the Wellbore,* http://www.eub.ca/docs/documents/bulletins/bulletin-2006-28.pdf The revised EUB policy may have been encouraged by a recommendation from the Canadian Association of Petroleum Producers that the "EUB should develop new guidelines, in consultation with industry, government and other key stakeholders, which would allow for concurrent production of usable water and NGC from multiple coal seams; guidelines should include procedures for either re-injecting this water into an aquifer of the same quality or to another approved use." Canadian Association of Petroleum Producers. 2003. *Natural Gas from Coal in Alberta: Position Paper prepared for the Canadian Association of Petroleum Producers*, p. 11, http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=72435 See also Alberta Energy and Utilities Board. 2006. *Bulletin 2006-32: Implementation of Revised Processes for the Management of Commingling from Two or More Pools in the Wellbore,* http://www.eub.ca/docs/documents/bulletins/bulletin-2006-32.pdf .

[426] Alberta Energy and Utilities Board. 2006. *Directive 044: Requirements for the Surveillance, Sampling and Analysis of Water Production in Oil and Gas Wells Completed Above the Base of Groundwater Protection,* http://www.eub.ca/portal/server.pt/gateway/PTARGS_0_0_264_232_0_43/http%3B/extContent/publishedcontent/publish/eub_home/industry_zone/rules__regulations__requirements/directives/directive044.aspx

perforations above the base of groundwater protection, if the monitored water production increases.

4.7 Handling produced water and water treatment

Produced water is water produced in conjunction with hydrocarbons. It is usually saline, and the volume is dependant on the particular formation. Even in dry formations (e.g., Horseshoe Canyon Formation and some tight gas and shale gas) a small quantity of water will condense out of the gas when it is brought to lower temperatures and pressures at the surface.

In Alberta produced water is usually disposed of in deep wells, which must be below the base of groundwater protection.[427] Deepwell injection can be quite safe, if the pre-existing stresses are satisfactory.[428]

A company can apply to the EUB for permission to manage produced water in different ways. If it can show that the practice will not harm the environment it will usually be given the approval for a pilot project for one year.[429] At the time of writing, surface discharge of produced water is not permitted in Alberta,[430] but non-saline water might be used in some way in the future, if certain conditions are met.[431] Alberta Environment is planning discussions on the beneficial use of produced water.[432] There are still some legal issues around this use that need to be resolved. At the time of writing "there are significant gaps in Alberta's legislative scheme to deal with putting diverted non-saline water to a useful purpose. Unless the re-use for a useful purpose was contemplated at the stage of the initial licensing, the [Water] Act does not well accommodate changes to allow re-use for useful purposes."[433] The legal situation is also unsatisfactory with respect to the diversion of saline water. Since the regulations exempt saline water from the requirement for a licence, it is uncertain how a company obtains authorization for the beneficial use of saline water.

It would be prudent to require the use of produced water in all water-short regions but, unless the water is being used for enhanced oil recovery, it will probably be necessary to first treat it. Such treatment should be feasible for water produced from the Horseshoe Canyon and Ardley formations, where the salinity is not too high. However, it is unlikely to be realistic to require the

[427] Alberta Energy and Utilities Board. 1994. *Directive 051. Injection Disposal Wells*, p. 4, http://www.eub.ca/docs/documents/directives/Directive051.pdf

[428] Edo Nyland, Professor Emeritus, University of Alberta, personal communication with Mary Griffiths, March 6, 2007.

[429] Brenda Austin, Alberta Energy and Utilities Board, personal communication with Mary Griffiths, January 22, 2007.

[430] Only surface run-off may be discharged, provided it meets the requirements set in Alberta Environment's *Surface Water Quality Guidelines for Use in Alberta*.1999, http://environment.gov.ab.ca/info/library/5713.pdf

[431] At the time of writing, before any non-saline groundwater is produced from a CBM well, the company "must apply to divert and use or dispose of non-saline groundwater under the *Water Act."* Alberta Environment. 2004. *Guidelines for Groundwater Diversion for Coalbed Methane/Natural Gas in Coal Development*, p. 2, http://www3.gov.ab.ca/env/water/Legislation/Guidelines/groundwaterdiversionguidelines-methgasnatgasincoal.pdf This will not apply to diversions under a certain volume when the proposed Code of Practice is introduced and the Guidelines are revised.

[432] Government of Alberta. 2006. *Coalbed Methane/Natural Gas in Coal Multi-Stakeholder Advisory Committee Final Report*, recommendations 3.5.1 and 3.5.2, http://www.energy.gov.ab.ca/docs/naturalgas/pdfs/cbm/THE_FINAL_REPORT.pdf

[433] Kwasniak, Arlene J. In press. "Waste Not Want Not: A Comparative Analysis and Critique of Legal Rights to Use and Re-use Produced Water – Lessons for Alberta", to be published in the *Denver Water Law Review*, spring 2007. This paper examines the current limitations in Alberta legislation, with respect to both non-saline and saline water and recommends how they can be addressed. The term "beneficial use of produced water" has a different meaning in western U.S. water law and western Canada water law. In this paper Kwasniak points out the distinction between the water law in the western U.S. where "beneficial use" has specific meaning in water law and in Alberta where water rights are associated with a licence to divert. Note that Kwasniak uses the term "useful purpose", rather than "beneficial use" to make a clear distinction with the meaning given to that term in the U.S.

treatment of highly saline water from the Mannville Formation (which may have 35,000 to 60,000 mg/l TDS). It is not yet certain what beneficial uses will be appropriate but Alberta Environment guidelines indicate potential uses, depending on the salinity of the water.[434]

Landowners and those living in areas where water is produced from shallow aquifers need to ensure that any water used for irrigation agriculture is suitable for both the crop and the local soils. Even water produced from fresh aquifers will need to be carefully handled to ensure there are no harmful environmental impacts. This is illustrated by a study of 44 water wells completed for domestic or agricultural use in aquifers in coal, mixed coal–sandstone and sandstone aquifers from the Paskapoo–Scollard Formation,[435] the Horseshoe Canyon Formation and the Belly River Group.[436] The samples were analyzed for a comprehensive range of characteristics, including trace elements, total dissolved solids (i.e., measure of salinity) and stable isotope composition. In all formations some of the samples exceeded the Canadian water quality guidelines in various ways, including the sodium adsorption ratio for irrigation water. The study reported, "Management of produced water from NGC [natural gas from coal] activities will require careful consideration of the water quality to ensure responsible disposal practices are followed, as certain of the parameters . . . will limit the available disposal or reuse options for the produced water."[437] Another study found that a number of inorganic elements and organic compound concentrations exceeded established environmental water quality guidelines.[438] Thus, even if the produced water is similar to domestic or agricultural well water, it may not be appropriate to use for irrigation or, in some cases, for watering livestock.[439] Another disposal option is to re-inject fresh water into another zone of comparable quality to replenish the aquifer. However, extreme caution is required here; it is difficult to do this without getting oxygen in the water, which would allow bacteria to develop.[440] Protection of the quality of an aquifer must be paramount.

Companies are examining technologies that can be used to treat produced saline water so that it can be used. The cost of energy for desalinization may have been a barrier but it is thought that

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[434] Alberta Environment. 1999. *Surface Water Quality Guidelines for Use in Alberta*, http://environment.gov.ab.ca/info/library/5713.pdf The Guidelines set standards for quality of water for agricultural use. They indicate that water with up to 3,000 milligrams per litre (mg/l) of total dissolved solids (TDS) may be suitable for livestock and water with between 500 and 3,500 mg/l /TDS may be suitable for irrigation. However, these are general values. A footnote to the Guidelines indicates the acceptable salinity levels for a range of crops. The suitability of water for irrigation also depends the sodium adsorption ratio of the soil. Livestock vary in their salt tolerance and the Alberta government provides information on the acceptable levels for different animals. Alberta Agriculture, Food and Rural Development, 2003, *Water Requirements for Livestock*, http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/agdex801

The *Surface Water Quality Guidelines for Use in Alberta* are also used in setting water quality based approval limits for the discharge of wastewater (see *Guidelines*, section 3). If an approval is given for discharge to surface waters, water quality should be regularly tested to ensure it continues to meet the Guidelines (since it is possible that the withdrawal of groundwater may draw in water with different characteristics). Surface discharge may be a problem in a cold climate, as water cannot be discharged when surface water or groundwater is frozen.

Some values in the Alberta tables are derived from Canadian Council of Ministers of the Environment. 2005. *Canadian Water Quality Guidelines for the Protection of Agricultural Water Uses*, http://www.ccme.ca/assets/pdf/wqg_ag_summary_table.pdf The Canadian Guidelines are expressed as micrograms (microns) per litre (which is the same as parts per million), whereas in Alberta the value for total dissolved solids is expressed as milligrams per litre (or in parts per thousand).

[435] The Ardley coal zone lies within the Scollard formation.

[436] Alberta Energy and Utilities Board/Alberta Geological Survey. 2003. *Chemical and Physical Hydrogeology of Coal, Mixed Coal-Sandstone and Sandstone Aquifers from the Coal-Bearing Formations in the Alberta Plains Region, Alberta,* EUB/AGS Earth Sciences Report 2003-04.

[437] Alberta Energy and Utilities Board/Alberta Geological Survey. 2003. *Chemical and Physical Hydrogeology of Coal, Mixed Coal-Sandstone and Sandstone Aquifers from the Coal-Bearing Formations in the Alberta Plains Region, Alberta*, EUB/AGS Earth Sciences Report 2003-04, p. xvii.

[438] See also Alberta Energy and Utilities Board/Alberta Geological Survey. 2007. *Water Chemistry of Coalbed Methane Reservoirs,* EUB/AGS Special Report 081, p.127, http://www.ags.gov.ab.ca/publications/SPE/PDF/SPE_081.pdf

[439] For example, water from coal seams may contain dissolved organic substances which may be harmful to livestock..

[440] Cliff Whitelock, personal communication with Mary Griffiths, September 22, 2006.

with one pair of technologies, capacitive desalination and deionization, "it may be possible to reduce energy consumption (per unit of water treated) to 1/100 or 1/1000 of the level using conventional methods, such as UV light or reverse osmosis."[441] When selecting a water treatment system it is important for a company to consider how the waste from the treatment process will be disposed of and which process is least likely to cause later environment problems. Waste salts and other waste may be in the form of a sludge that is sent to a landfill, or a liquid that is injected into a disposal well. Landfills must have liners and a leachate collection system, but it is also essential to ensure that they are carefully sited to minimize the risk of groundwater contamination as a result of salts leaching from the landfill. Researchers have found that, "While injecting concentrates into disposal wells probably has the least environmental impact, disposing concentrates and effluent sludge in landfills could have significant environmental and ecological impact on the nearby soil and groundwater due to the high concentration of acids, hydrocarbon residues, trace metals and other contaminants."[442]

In the U.S. the handling of produced water has been identified as one of the key challenges for CBM development. This is because some coals (for example, in the Powder River Basin in Wyoming) produce a lot of water that is fresh or of relatively low salinity, so this water either can be used directly on the land or requires very little treatment prior to surface use. Companies operating in the area are seeking new technologies to improve the beneficial use of water in arid climates and the re-injection into potable aquifers for recharge.[443] In Alberta the geology is different and the total volume of low-salinity produced water, which is suitable for treatment, is expected to be very low in comparison with the U.S. The legal framework in Alberta with respect to the discharge and use of produced water is also different from the U.S.[444]

4.8 Well abandonment

When a well is abandoned measures must be taken to protect fresh groundwater. These are set out in EUB *Directive 20.*[445] In a well that has been cased, all non-saline groundwater must be shut off with cement, so there are no flows (of water or gas) between different porous zones. This involves checking the cement between the casing and the formation and repairing it to ensure there is no risk of cross-flows. If a well has been drilled but did not produce (called an open-hole abandonment) the company must insert cement plugs covering all non-saline groundwater and isolate all porous zones. The wellhead must be capped, as set out in the EUB directive. The space (annulus) between the surface casing and the next (second) casing string must be left open to ensure that there is no buildup of gas below the cap, and the operator must test for a flow of gas from the surface casing vent. The directive also sets out the procedure to

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[441] Petroleum Technology Alliance Canada. 2006. *Filling the Gap: Unconventional Gas Technology Roadmap,* p. 39, http://www.ptac.org/cbm/dl/PTAC.UGTR.pdf Today capacitive desalination is costly and is only capable of handling water with a TDS count of 2,500 ppm, but there are plans to make it effective for water with up to 15,000 ppm. A new distillation technique, called a rapid spray system, may cost about 1/8th of current options. Note that ultraviolet light disinfects but does not desalinize water.

[442] Hum, Florence, Peter Tsang, Thomas Harding and Apostolos Kantzas. 2005. *Review of Produced Water Recycle and Beneficial Reuse.* Institute for Sustainable Energy, Environment and Economy, University of Calgary, p. 29.

[443] Research Partnership to Secure Energy for America. 2005. *Technology Needs for U.S. Unconventional Gas Development, p. 41.*

[444] Kwasniak, Arlene J. In press. "Waste Not Want Not: A Comparative Analysis and Critique of Legal Rights to Use and Re-use Produced Water – Lessons for Alberta", to be published in the *Denver Water Law Review,* spring 2007.

[445] Alberta Energy and Utilities Board. 2003. *Directive 020: Well Abandonment Guide,* http://www.eub.ca/docs/documents/directives/Directive020.pdf In some specific cases the EUB may waive the requirement to cover all non-saline groundwater with cement, e.g., where remedial cementing has repeatedly failed. See Appendix 3 in the Directive. A summary of requirements is provided in Bulletin 2005-04*: Shallow Well Operations,* http://www.eub.ca/docs/documents/bulletins/Bulletin-2005-04.pdf

test for gas migration, and any detected leaks must be reported and repaired. If wells (including domestic water wells) are not correctly abandoned, gas may migrate up the wellbore. Additional work needs to be undertaken to ensure the integrity of abandoned wells. According to a report sponsored by the Canadian Council of Ministers of the Environment, "The threat to groundwater quality from all aspects of past activities (from exploration, through field production, storage, transportation, and refining/petro-chemical production) represents a major challenge to governments and industry. For example, recognition that little is known about the long-term integrity of concrete seals and steel casing in the hundreds of thousands of abandoned wells across Canada is required."[446] Well abandonment is especially important with the prospect of the use of carbon dioxide for enhanced oil or CBM recovery, or its long-term storage in deep geological formations. Disposal wells, where produced water is injected, must also be carefully abandoned. In some situations observation wells may be required to monitor movement of the fluids.

[446] Crowe, Allan, Karl Schaefer, Al Kohut, Steve Shikaze, Carol Ptacek. 2003. *Groundwater Quality,* p. 28, Canadian Council of Ministers of the Environment. Winnipeg, Manitoba, CCME Linking Water Science to Policy Workshop Series. Report No.2, 52 pages. http://www.ccme.ca/assets/pdf/2002_grndwtrqlty_wkshp_e.pdf

5. Best Management Practices for Industry

We tend to take water for granted while the supply is sufficient. Some parts of Alberta are already dry and, with climate change, a growing population and expanding industrial demands, the finite nature of water resources in Alberta is becoming increasingly apparent. The first step in conservation is to bring about a change in attitude. Water conservation means limiting our use of water and also protecting its quality. What can companies do? "Don't assume water will always be here," is one principle identified in a report written for the business community.[447] Industry must ensure that its actions do not reduce the water available for use in rural Alberta, and companies are encouraged to become leaders in reducing or eliminating the use of water in their operations. The government has basic regulations in place and companies should be diligent in reporting any infringements. Proactive companies recognize the importance of good stewardship and go beyond the minimum requirements set by government. Best management practices identify measures that proactive companies can take in addition to the basic regulatory requirements. For example, the Canadian Association of Petroleum Producers compiled a manual on best management practices for CBM,[448] and at the time of writing the association is preparing a manual on best practices with respect to water use. A company will determine which best practices it adopts based on company policy, local conditions and economics. The following list identifies practices that concerned landowners would like companies to consider:

- Provide landowners with a regional development scenario incorporating existing, planned and reasonably foreseeable development, showing existing wells, the expected number and approximate location of proposed wells, tanks (for glycol or produced water), compressor stations and pipelines.
- Conduct an environmental impact assessment as part of the regional development scenario, indicating how water bodies (including wetlands), alluvial aquifers and sensitive vegetation will be avoided and protected.[449] The assessment should also indicate how the cumulative impacts will be minimized, for example, by cooperating with other companies to make use of existing cut lines, pipelines, service roads and compressor stations.
- Hold one or more open houses in the area to be affected by a project before any development starts, to present the regional development scenario (including the initial information gathered for the environmental assessment) and to learn about landowner

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[447] World Business Council for Sustainable Development. 2006. *Business in the World of Water: The WBCSD Water Scenarios to 2025,* p.45, http://www.wbcsd.org/DocRoot/Q87vukbkb5fNnpbkbLUu/h20-scenarios.pdf

[448] Canadian Association of Petroleum Producers. 2006. *Best Management Practices: Natural Gas in Coal/Coalbed Methane*, p. 33, http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=103407

[449] A water body is defined as "any location where water flows or is present, whether or not the flow or the presence of water is continuous, intermittent or occurs only during a flood, and includes but is not limited to wetlands and aquifers …" See *Water Act*, section 1(ggg) for the full definition, which excludes most irrigation works. Alluvial aquifers have a significant role in recharging groundwater aquifers and in cleaning and recharging surface water bodies. They also retain flood waters, thus reducing flood erosion and other flood damage. Since they are shallow, any contamination of alluvial aquifers may lead to immediate and irreversible contamination of adjacent surface waters and aquifers.

and public concerns relating to the project.[450] Respond to questions, or commit to provide answers if the company does not yet have the appropriate information. Revise the environmental review based on the public input.

- Keep the public informed and hold additional public meetings as needed.
- Conduct a baseline review of groundwater in an area before starting operations that could have any impact on shallow groundwater. [451] This includes operations to produce gas (both conventional and unconventional gas) that is below the base of groundwater protection if there are permeable formations between the gas wells and base of groundwater protection.
- Meet with individual landowners to identify the location of water wells (old and current), flood plains and water bodies (including wetlands and natural and enhanced drainage ditches) that need protection. The distance within which these features should be identified will vary.[452]
- Offer to conduct baseline water well testing for water wells within 880 metres of a proposed gas well, or further if requested by the landowner, until there is sufficient published evidence to show that wells at that distance will not be impacted.[453, 454] Results should be given to each landowner and submitted to Alberta Environment or the EUB to establish a database on all aquifer characteristics, including gas.
- If it is not possible to conduct a baseline test of adjacent water wells (for example, because a landowner does not want his or her water well tested or there are technical problems with conducting a pumping test in an old well), consider installing a monitoring well on the lease site to monitor groundwater quality and quantity in the aquifer being used for the water well.
- Test the composition and isotopic characteristics of gas (and water) from the formation where the gas is produced, for a representative number of gas wells. This should be done before any production gas is commingled. Results should be submitted to the EUB/Alberta Environment database to provide a baseline if there are any future problems with gas migration (see Chapter 7 for more information).

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[450] See, for example, Alberta Energy and Utilities Board. 2006. "Land Challenge Pilot Projects Planned for Innisfail and Carstairs Areas", *Across the Board,* October, p.1 and 3, *http://www.eub.ca/docs/products/newsletter/pdf/atb_october_2006.pdf*

[451] One company, for example, commissioned and published an overview of groundwater resources in their planned area of operation. MGV Energy Inc. 2005. P*roposed NGC Development. Groundwater Newsletter – Ferrybank Area.* December. The newsletter was prepared by Hydrogeological Consultants Ltd. Similar newsletters were published for the Ghost-Pine area, New Norway and Penhold.

[452] Alberta Environment's Preliminary Groundwater Assessment sets 1.6 km as the distance for a field-verified survey of water wells, springs and dug-outs. See Alberta Environment. 2003. *Groundwater Evaluation Guideline (Information Required when Submitting an Application under the Water Act), http://environment.gov.ab.ca/info/library/7508.pdf* Companies should recognize the importance of avoiding wetlands. See Alberta Wilderness Association, news release, March 7, 2007.*EnCana Ignores CFB Suffield Rules and Ignores Sensitive Wetlands at Suffield, http://news.albertawilderness.ca/*

[453] Some members of the Coalbed Methane/Natural Gas in Coal Multi-Stakeholder Advisory Committee recommended a distance of 880 metres, but the committee did not reach consensus on this number. See Government of Alberta. 2006. *Coalbed Methane/Natural Gas in Coal Multi-Stakeholder Advisory Committee Final Report*, p. 25, *http://www.energy.gov.ab.ca/docs/naturalgas/pdfs/cbm/THE_FINAL_REPORT.pdf*

[454] Several operators routinely test water wells outside the radius required by EUB regulations as it has the potential to eliminate uncertainty at a later point during production operations. A hydrogeological study in an area where CBM wells were to be drilled in the Horseshoe Canyon Formation recommended that background data be collected for the water wells within 500 metres of the proposed CBM well, irrespective of its depth. MGV Energy Inc. 2005. *Proposed NGC Development. Groundwater Newsletter – Ferrybank Area*, p. 9.This predated Alberta Environment's 2006 requirement to provide baseline water well testing for water wells adjacent to CBM wells that are drilled above the base of groundwater protection.

- Check the integrity of the casing in shut-in and abandoned oil and gas wells in the area around the proposed well to minimize the risk of leakage if there is gas migration.[455] If recompleting an existing well (to produce gas in a different formation) a new cement bond log should be run, before new perforations are made. This is especially important for old wells where the cementing may not meet today's standards. The integrity of pipelines should also be checked, especially if there is a change in use.[456]
- Use uncontaminated (fresh) water for the preparation of drilling mud to avoid any risk of contaminating shallow aquifers if there is loss of circulation while drilling.[457] This water should be obtained by treating produced water (where available), rather than using fresh sources.
- Use a non-toxic mud system for drilling a gas well through all formations above the base of groundwater protection.
- Avoid drilling for gas in formations that are above the base of groundwater protection. This is the best way to minimize the risk of impacts on aquifers containing fresh water.
- If a company finds that a well produces non-saline water, it should compare, on a monthly basis, groundwater production and the presence of any gas with previously collected data, so that any changes are identified early. Alberta Environment and the EUB should be informed of these changes, even if the company is still in compliance. Of course, this recommendation only applies if a company has evaluated the previous recommendation and consciously chosen to apply to produce above the base of groundwater protection.
- Drill multiple wells from one pad where the produced zone is deep enough to make this possible, as this reduces not only the surface impact of operations but also the length of pipeline required to remove and inject any produced water (thus reducing the chance of a saline water leak).
- Notify owners of adjacent water wells if there is loss of circulation during drilling, providing information about the drilling mud and offering to monitor the water well for any changes in groundwater quality.[458]
- Use tanks for drilling mud, not in-ground sumps, to avoid contaminating groundwater (since pooled water can migrate downwards). Use of tanks also facilitates the recycling of the water.
- Carefully evaluate the disposal of drilling mud. The EUB requirements, which are set out in *Directive 50*, allow some types of drilling waste to be spread on the surface if the EUB considers there will be no harmful impact on the environment.[459] The Pembina

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[455] One landowner and former oil patch operator has suggested that this check should be conducted on all wells within one mile. Personal communication with Mary Griffiths, September 28, 2006.

[456] See section 4.4.1 for information on leaks from water pipelines and Alberta Energy and Utilities Board. 2006. *ST 99-2006: Provincial Surveillance and Compliance Summary 2005,* p. 77. Despite some reduction in the number of incidents, corrosion continues to be the main cause of pipeline leaks, *http://www.eub.ca/docs/products/STs/st99_current.pdf*

[457] See, for example, the recommendation that fresh water be used in the drilling of the well and in the preparation of the drilling mud in MGV Energy Inc. 2005. *Proposed NGC Development. Groundwater Newsletter – Ferrybank Area,* December, p. 9.

[458] MGV Energy Inc. 2005. *Proposed NGC Development. Groundwater Newsletter – Ferrybank Area,* December, p. 9.

[459] Alberta Energy and Utilities Board. 1996. *Directive 050. Drilling Waste Management,* Sections 3 and 4, *http://www.eub.ca/docs/documents/directives/Directive050.pdf*

Institute accepts that non-toxic drilling waste, which has been thoroughly dewatered in a tank, may be disposed of by mix-bury-cover with landowner consent, if suitable subsurface conditions are present. However, it is often preferable to send the dewatered wastes to landfill, with water that is not suitable for reuse in drilling mud being sent for deepwell injection. Surface soil is a valuable resource and should not be used as a waste receptor.

- Adopt the precautionary principle when fracturing formations, and conduct no fracturing above the base of groundwater protection until companies can guarantee that there would not be any harmful impacts on fresh groundwater.
- Minimize the risk of contamination in aquifers that are below the base of groundwater protection. In the future, there may be a need to drill to deeper zones to extract water, if shallow aquifers recharge more slowly due to climate change. Even though the deeper water may not be directly potable, it will be possible to treat the water to remove the salts. However, it could be much more difficult and costly to remove other substances, such as those used for fracturing.
- If, despite the above recommendation, fracturing is conducted above the base of groundwater protection, ensure that there is ample distance between the fracturing and water wells. One hydrological consultant recommended that if CBM wells above the middle part of the Horseshoe Canyon Formation were to be stimulated "a minimum vertical separation of 50 metres be maintained between the bottom of the deepest water well within 500 metres of the NGC well and the top of the shallowest zone to be stimulated in the NGC well."[460] This is more cautious than the EUB's requirement, set out in *Directive 27* on shallow fracturing, that specifies a minimum of a 25-metre vertical separation and a 200-metre horizontal separation, during the period that the board is reviewing the issue.[461]
- If fracturing gas wells above the base of groundwater protection, drill a water-monitoring well to monitor the impact of shallow fracturing on the adjacent non-saline aquifer.
- If fracturing above the base of groundwater protection with water, use treated water (or chlorinate it) to avoid contamination of aquifers. Consider the merits of treating produced water for use and also recycle the fluids.
- Avoid the use of potentially toxic substances in fracturing fluids above the base of groundwater protection, as required by the EUB, and tell landowners what substances are being used if they request the information.[462]
- Find the most productive use for any produced non-saline water. If, despite the above recommendations, there is production of gas and water above the base of groundwater protection, the water could be treated and offered to local landowners. Alberta Environment must give approval for any diversion and use of non-saline water, but the onus is on the company to develop constructive and proactive uses. The company should

[460] MGV Energy Inc. 2005. *Proposed NGC Development. Groundwater Newsletter – Ferrybank Area,* p..9.

[461] Alberta Energy and Utilities Board. 2006. *Directive 027: Shallow Fracturing Operations – Interim Controls, Restricted Operations, and Technical Review,* http://www.eub.ca/docs/documents/directives/Directive027.pdf

[462] Companies may not be willing to provide information on fracturing fluids, unless it is mandated by government, because some of the gelling chemicals are carefully guarded trade secrets of the fracturing companies.

ensure that the water is treated, if necessary, and regularly monitored to meet Alberta Environment standards.

- Look for ways to use produced saline water. Saline water may be used to replace non-saline water for enhanced oil recovery in the area. A company that produces saline water can take the initiative by informing other operators in an area about the volume of water it is producing. This will assist those who have to meet Alberta Environment's requirement for companies to search for alternative sources of water before they apply for water for enhanced oil recovery.[463] It may be possible to find companies to use the water beyond the distances stipulated by Alberta Environment. A company may also consider whether it would be worthwhile to treat saline water for beneficial use, rather than sending it for deep well injection. However, the full environmental impacts should be considered (including the energy used for desalinization and the potential impact of the waste disposal), before deciding whether treatment of saline water is justified at the present time.
- Assess and adopt energy efficient processes for handling produced water. For example, solar power is being developed for use in remote locations.[464] Solar energy is likely to be most suitable for shallow gas or other situations where the volume of water to be pumped is low. However, a complete energy balance should be evaluated when considering different options.

The above list of suggestions is generic and the most suitable best practices will depend on the local situation. Thus a wise proactive company will inform the local community about a project at an early stage and meet with landowners who have a good understanding of the local area and conditions. Together they can determine which best practices are appropriate for the local situation. We also encourage companies to read Chapters 6 and 7 of this report.

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[463] Alberta Environment. 2006. *Water Conservation and Allocation Guideline for Oilfield Injection,* *http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_GUIDELINE.pdf* See also the *Water Conservation and Allocation Policy for Oilfield Injection*, *http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_Policy.pdf*

[464] See, for example, Clark, Greig (Enhanced Recovery Services Inc.) and Michelle Gaucher (City of Medicine Hat – Gas Utility). 2006. *A New Solar (or Wind) Powered Pump System for Dewatering Shallow Gas Wells – A Case History*. Petroleum Technology Alliance Canada Shallow Gas Production Technology Forum. March 15, Calgary.

6. What Landowners Can Do

This chapter highlights issues that landowners may want to discuss with a company before a well is drilled on their land, or before many wells are drilled in their area. It identifies points that a landowner may want to resolve with a company before deciding whether to sign a lease agreement and sets out ways in which landowners can work with companies to minimize the risk of impacts to fresh water resources.[465] Landowners who are well informed on potential water impacts should be able to negotiate best practices with a company operating on their lands. This may include, for example, arranging for the company to avoid wetland areas, provide additional setback distances from surface water bodies and conduct baseline testing of water wells where it is not already a government requirement. Some landowners may want to learn more about the proper operation and maintenance of water wells, especially those who are new to rural Alberta.

6.1 Learning from others

Since conditions vary across the province, it is a good idea for landowners to talk to neighbours and inquire about their experience with gas development on their land. Many landowners in Alberta are joining together to find out what they can do to reduce the impacts of gas development in their communities. A number of new groups have been established in recent years. Some, such as those affiliated with the Alberta Surface Rights Federation, are landowner groups, while others are synergy groups. Surface rights groups usually consist of landowners who push for higher standards of practice in their area. Surface rights groups work in a synergistic manner, openly communicating and collaborating with industry and government, while maintaining control of the process through their exclusion of industry membership or funding. In addition to landowners, synergy groups include representatives from industry and government as members and funding sources. They work together to resolve issues and ensure that development occurs in an appropriate manner. Landowners who are unable to locate a group via Synergy Alberta or the Alberta Surface Rights Federation can inquire about local groups at their regional EUB office.[466]

Landowners may sometimes learn from unconventional gas development in the U.S.,[467, 468] but it is important to remember that some industry practices in parts of the U.S. are not allowed in Alberta (e.g., surface discharge of water without a permit) and that the geology is also different. This does not mean that problems cannot occur in Alberta, and it is important for industry,

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[465] Griffiths, Mary, Chris Severson-Baker and Tom Marr-Laing. 2004. *When the Oilpatch Comes to Your Backyard: A Citizens' Guide,* The Pembina Institute. This report, which can be purchased from the Pembina Institute, provides comprehensive information on all the issues that landowners may wan t to discuss with a company before they sign a surface lease or right of way agreement.

[466] The Synergy Alberta web site is at *http://www.synergyalberta.ca/groups/index.html*

[467] Sumi, Lisa. 2005.*Oil and Gas at Your Door,* Oil and Gas Accountability Project, Colorado. *http://www.earthworksaction.org/pubs/LOguide2005book.pdf*

[468] Karen Brown, 2006. *Perception vs. Reality: A Fact-Based Toolbox.* November 15, presentation to the Canadian Society for Unconventional Gas, Annual Conference: The speaker, from the Coalbed Natural Gas Alliance, examined CBM development in the Powder River Basin. The Alliance includes industry and ranchers, etc., *http://www.cbnga.com/index.htm*

government and landowners to learn from mistakes made elsewhere and be vigilant not to repeat them.

Those who are new to the process, do not feel that their knowledge is current or feel burdened by dealing with industry should consider engaging the assistance of a land advisor, land advocate, land agent or lawyer who has experience working with energy companies and landowner concerns. Responsible companies will not only encourage independent representation, but will cover reasonable costs.

If a landowner and company cannot agree on terms and conditions, they can make use of the EUB's Appropriate Dispute Resolution process and, if that process fails, they may get a hearing before the EUB. If a landowner is unable to resolve any issue through discussion with a company or via the EUB's Appropriate Dispute Resolution Process, he or she may want to contact a lawyer. Since any impact on water is an environmental issue, the landowner can contact the Environmental Law Centre.[469]

In cases where there is an issue about the level of compensation, the Surface Rights Board (SRB) will hold a hearing and determine the amount of compensation that a company must pay. It is important to note that landowners should not be discouraged from utilizing either the EUB or the SRB processes as they are intended to provide balance between the landowner and the company seeking access.

Advice on negotiating with a gas company is provided in the Pembina Institute's publication *When the Oilpatch Comes to Your Backyard: A Citizen's Guide.*[470] This guide summarizes government requirements for all stages of oil and gas development, from exploration and surveying through drilling and operations to reclamation. It lists issues to consider before deciding whether to allow seismic activity on private property or before signing an agreement for a well or other facility, or a pipeline right-of-way. It also identifies which government agency should be contacted about a variety of issues that may occur during operations and gives information that is helpful not only for landowners but also for those who live adjacent to operations. Landowners may also wish to contact the Farmers' Advocate Office for more information on how to find an appropriate lawyer or land advisor.

6.2 Negotiating for best management practices

This section lists some of the key things that a landowner might want to consider with respect to water before signing a lease agreement. In addition, any conditions or commitments that both the landowner and the company agree to should be in writing and signed by both parties. This is often done by adding clauses to a surface lease agreement. Good written records, signed by both parties, help prevent problems in communication and create better working relationships.

[469] The Environmental Law Centre is a registered charitable organization that provides information on environmental and natural resources law to the public. Centre staff respond to questions about environmental and natural resources law and, where needed, make referrals to law firms and lawyers with environmental expertise. The Environmental Law Centre can provide information on common law actions, e.g., for trespass or negligence, although such cases are often difficult to prove. However, the Centre does not undertake actions on behalf of clients. They can be contacted toll-free in Alberta at 1-800-661-4238.

[470] Griffiths, Mary, Chris Severson-Baker and Tom Marr-Laing. 2004. *When the Oilpatch Comes to Your Backyard: A Citizens' Guide.* Second edition. The Pembina Institute.

6.2.1 Seismic exploration

Seismic exploration is often the first indicator of oil and gas development coming onto the land and can either enhance or detract from a landowner's perception of the experience that lies ahead. Landowners are often approached by a permit agent seeking permission for a company to conduct seismic exploration. A landowner does not have to allow seismic operations on his or her land, but, if he or she refuses, the company may conduct its operations in an adjacent road allowance, where it is not possible to set conditions on how the work is carried out.

Permit agents who work on behalf of a seismic company are not the same as licensed land agents. While a training program has been introduced for geophysical permit agents,[471] training is not mandatory and not all permit agents respect a code of ethics. Although Alberta Sustainable Resource Development's Geophysical Inspector will investigate complaints (see below), the work of permit agents is not routinely monitored by government. Permit agents who have completed the training to become a geophysical permit agent are given a certification number and the government recommends that "A landowner should request the geophysical permit agent's certification number be recorded on the permit form to confirm that the geophysical permit agent has completed the industry and government recognized program."[472] Landowners may also want to request information on the energy company that has contracted the seismic work, and provide follow-up comments to the energy company if their experience is negative.

Landowners should arrange for the seismic company to keep the shot points (where the explosions or mechanical vibrations are sent out) away from low-lying areas, surface water and wetlands. If the company drills shot holes for explosive charges, it is important to ensure they are properly plugged to avoid risk of contaminants reaching groundwater. The standard requirement is for a plastic plug to be put not less than one metre below the surface and for the hole above the plug to be filled with bentonite pellets and topped with drill cuttings. Landowners can negotiate with the company to put the plug closer to the bottom of the hole and fill from the plug to surface with bentonite pellets in the manner recommended in *Water Wells that Last for Generations.*[473] Landowners should ensure that all conditions and the agreed compensation are written into the permit agreement, and that it is signed by both parties before a company starts operations. The charge put in the shot hole must be detonated within 30 days and the company must return to permanently abandon the holes and refill any shot holes that have blown out. It is advisable that a landowner take some responsibility in monitoring that the conditions negotiated are adhered to, including filling of the holes, since unfilled holes may provide a pathway for groundwater contamination (as well as a hazard to those walking over the land).[474]

A landowner who has any concerns about damage or the abandonment of the shot holes resulting from seismic exploration should call the government's geophysical inspector.[475] While not responsible for enforcing any additional terms and conditions freely negotiated between the landowner and the company, the geophysical inspector will check whether the standard

[471] The Canadian Association of Geophysical Contractors has arranged training through the Petroleum Industry Training School and they also recommend best practices, https://www.cagc.ca/

[472] Alberta Sustainable Resource Development. *Geophysical Inspector Program,* http://www.srd.gov.ab.ca/land/m_geo_inspector.html

[473] Alberta Agriculture, Food and Rural Development. 2001. *Water Wells that Last for Generations,* Module 8, http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/wwg404 Call 1-800-292-5697 (toll free) for a printed version.

[474] A landowner should also monitor for flags, wire and garbage left on the land.

[475] The geophysical inspector can be reached by calling 780-427-3932. Alberta Sustainable Resource Development is responsible for the geophysical inspector program, http://www.srd.gov.ab.ca/land/m_geo_inspector.html

procedures have been met, and require the company to return if the work fails to meet those standards. Landowners who believe the company did not meet their negotiated conditions are advised to contact the company and request its cooperation in returning to the site to rectify the situation. If problems persist, the landowner should then contact the energy company hired to complete the seismic work. Failing a positive outcome, the landowner may wish to suggest an arbitrator be engaged to sort out the concerns and, as a last resort, may have to engage the services of a lawyer. Neither the EUB nor the Surface Rights Board handle complaints regarding seismic exploration.

6.2.2 Gas well setbacks

The EUB specifies minimum distances between a water well or water body and a gas well (see section 3.1.3.1). However, a landowner may want to negotiate a greater distance or additional measures to protect both surface water and groundwater. This might include ensuring that a gas well is located as far as possible from wetlands or from any existing or abandoned water wells. It is often possible for a company to relocate a gas well at the planning stage, particularly if the well is for deep CBM. If the landowner finds that the proposed well location is unacceptable, he or she should make the company aware of his or her concerns and not sign the Surface Lease Agreement until an independent geologist confirms the necessity for the specific location requested. The EUB can assist a landowner in determining the requirement for any specific location.

6.2.3 Baseline testing of water wells

Before they start drilling, companies are required to offer to test water wells adjacent to CBM wells that are to be perforated above the base of groundwater protection, as explained in section 3.2.3.1. However, some landowners negotiate for a company to provide and pay for water testing that is of a higher standard than currently required by Alberta Environment and the EUB. One landowner group has engaged expert advice to develop criteria for an expanded baseline test.[476] Thus a landowner may want to negotiate that the company should test for dissolved gas and other substances in a water well, if it is adjacent to a CBM or other type of gas well, even if testing is not required by government. A well test provides baseline data with which to compare future test results if there is a problem later. A water well test should cover both the yield and water quality and should be conducted before the gas well is drilled. A landowner may also want to negotiate that the test results be returned to the landowner prior to commencement of drilling. Some landowners have experienced difficulties when the initial testing results have been lost and drilling has already been completed. It is then impossible to compare later results with the pre-

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[476] The Wheatland Surface Rights Action Group (WSRAG) commissioned a report, *Groundwater Supply Concerns Regarding CBM Development – Wheatland County*, which was completed by A.M. McCann, Director of Omni-McCann Consultants Ltd., who holds a permit to practice from the Association of Professional Engineers, Geologists and Geophysicists of Alberta. As a result, WSRAG compiled *Water Testing Recommendations*, February 13, 2007. This includes the following recommendations related to baseline testing by industry:

“Industry should provide an expanded set of baseline water tests, above what is required by the EUB and Alberta Environment.

1) Baseline testing should also include: color, dissolved methane, barium and strontium in the laboratory testing suite of parameters

2) Record field parameters when stabilized (samples should not be collected until field parameters have stabilized). Field parameters should include pH, electrical conductivity, temperature, turbidity, alkalinity and hydrogen sulphide. Barometric pressure should also be recorded at the time of sampling.

3) Identify well conditions that may affect sampling results such as a gas shroud installed on the well pump, the pump setting, excessive well losses/water drawdown during pumping (particularly if pumping results extends over more than one aquifer) and well intake length.

4) Baseline testing should include the collection of at least two samples, preferably in the spring and fall.

drilling situation. In its requirements for baseline water well testing, Alberta Environment indicates that a new test is not needed if the landowner has the results from a test conducted within the previous two years and the tests were done as specified in the testing protocol. However, a landowner can still ask for the testing to be done again. Alberta Environment's baseline water well testing protocol for CBM wells indicates which substances should be included in a test, and its protocol can be followed for all water well testing near gas wells.

In situations where baseline water well testing is not mandatory, the distance within which a company will test a water well will probably depend on the company, the type of gas well being drilled and the perseverance of the landowner. Landowners, including landowners adjacent to the proposed gas well, may want to negotiate to have their water well(s) tested. Some companies routinely test water wells within 600 metres of a CBM well, irrespective of the CBM well depth, and many agree to test water wells at a great distance.[477] Distances for other types of gas well may vary.

Landowners should make sure that the water well test is carried out in the way outlined by Alberta Environment for CBM wells that are drilled above the base of groundwater protection and that the company sends the test to a laboratory that is accredited for those specific tests by the Canadian Association of Environmental Analytical Laboratories. Landowners should always ask for a copy of the test results and keep them in a safe place, in case there should later be problems. If a company refuses to test a water well that a landowner wants tested, the EUB can be asked to facilitate a meeting. If agreement still cannot be reached, the EUB Appropriate Dispute Resolution process should be used, as mentioned in section 6.1.[478] If there is still no agreement, the company must file a non-routine application. This means that the EUB will look at the outstanding issues before it decides whether it will issue a (gas) well licence. In some cases, an adjacent landowner may have a water well closer to a proposed gas well than the actual landowner who signs a lease agreement. In such cases it is thoughtful to inform the company about the adjacent water well, and require that it contact the adjacent landowner to inquire if he or she would like to have his or her water well tested.

A landowner who has a problem with a water well after a new gas well has been drilled should immediately contact the company and Alberta Environment. As pointed out in section 3.2.3.1, when a company has conducted baseline water well testing prior to drilling a CBM well that is above the base of groundwater protection, it must retest if later requested by the landowner.[479] In this situation, Alberta Environment must be told before the company retests the well.

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[477] For example, the Wheatland Surface Rights Group has developed an addendum to the Surface Lease Agreement, that has been accepted by some companies, which states: "Water Testing: Prior to commencement of any drilling activity, the Lessee shall offer to test any water well within 1.6 km of the lease …"

See also Alberta Energy and Utilities Board. 2006. *Decision 2006-102: EnCana Corporation Applications for Licences for 15 Wells, a Pipeline, and a Compressor Addition Wimborne and Twining Fields*, October 31, p.15, http://www.eub.ca/docs/documents/decisions/2006/2006-102.pdf At the EUB hearing, which was prior to Alberta Environment's new baseline water well testing requirement, EnCana committed to test all water wells within 400 metres radius, an additional 11 wells between 400 and 880 metres, and all high-yield water wells within 1000 metres. This included testing for free gas and, if free gas were detected, it would be sampled for methane content.

[478] Alberta Energy and Utilities Board. 2006. Public zone dealing with the EUB process, including appropriate dispute resolution, http://www.eub.ca/portal/server.pt?open=512&objID=230&PageID=0&cached=true&mode=2

[479] Alberta Environment. 2006. *Standard for Baseline Water-Well Testing for Coalbed Methane/Natural Gas in Coal Operations*, http://www.waterforlife.gov.ab.ca/coal/docs/CBM_Standard.pdf

6.2.4 Locating and checking old oil, gas and water wells

One route for gas migration is via the casing of old wells (see section 4.5). If gas is leaking to the surface, it will be evident in poor vegetation growth around the wellhead. Any landowner who knows of an old oil or gas well where the vegetation appears to be affected, should tell the company and ensure that the well is correctly abandoned, so there is no pathway for gas migration. It is also important to ensure that any old water wells in an area are correctly abandoned to avoid the risk of aquifer contamination.

6.2.5 Protection of fresh aquifers

As explained in section 4.2.1, some landowners are concerned that use of untreated water for drilling could contaminate shallow aquifers. Although the risk is probably small, it is a good idea to find out the source of the water the company plans to use and discuss whether additional treatment is required. In addition to discussing the water source, landowners may be interested in what substances are being used in drilling mud or for fracturing if this is taking place above the base of groundwater protection. A company may be willing to show the landowner the MSDS for the product (see section 4.2.1).

If a natural gas well is producing from above the base of groundwater protection, the company must notify the EUB if the well produces more than 5 m^3/month of water (see section 3.1.3.1).[480] Landowners may want to ask the company to inform them at the same time as it notifies the EUB of the measures being taken to prevent contamination of fresh water aquifers.

If natural gas wells are drilled into shallow formations (that is, above the base of groundwater protection, where the water is fresh), landowners might want to negotiate the location of monitoring wells or piezometers, especially if the company plans to fracture the formation or withdraw water from shallow coal seams to produce the gas. A piezometer is like a small well that measures the hydraulic head (that is, the pressure) in an aquifer. Landowners should ask how monitoring information will be reported to them and the public.[481]

To protect fresh water aquifers, it is also important to ensure good practices when drilling water wells, whether for industrial, agricultural or domestic use. Alberta Environment sets out requirements for the drilling of water wells.[482] New water wells should be carefully located and constructed to maximize the well life and protect groundwater, as explained in *Water Wells that Last for Generations.*[483] It is, for example, important to pay attention to the siting of the well, to ensure easy access for cleaning and maintenance and to check that surface water does not collect around the wellhead, as this could lead to contamination of water in the well and provide a pathway to contaminate an aquifer. Further advice on the protection of water sources can be

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[480] Alberta Energy and Utilities Board. 2006. *Directive 044: Requirements for the Surveillance, Sampling and Analysis of Water Production in Oil and Gas Wells Completed Above the Base of Groundwater Protection,* http://www.eub.ca/docs/documents/directives/directive044.pdf .

[481] Alberta Energy and Utilities Board. 2006. *Decision 2006-102: EnCana Corporation Applications for Licences for 15 Wells, a Pipeline, and a Compressor Addition Wimborne and Twining Fields,* October 31, p. 25, http://www.eub.ca/docs/documents/decisions/2006/2006-102.pdf The EUB required EnCana to install a groundwater monitoring well in the deepest aquifer within 50 metres of the CBM well in the EnCana project that has the shallowest surface casing depth. Details on the monitoring requirements are provided in the Decision.

[482] Government of Alberta. 1998 and updates, *Water (Ministerial) Regulation, Part 7,* http://www.qp.gov.ab.ca/documents/Regs/1998_205.cfm?frm_isbn=9780779720699 A Class A approval is required for the drilling of water wells for the diversion and use of groundwater, including other types of work related to water wells, described in Schedule 5 of the regulation. It includes the construction of a water well by digging as well as drilling.

[483] Alberta Agriculture, Food and Rural Development. 2001. *Water Wells that Last for Generations,* http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/wwg404 A printed version can be obtained by calling 1-800-292-5697 (toll free).

obtained through the Environmental Farm Plan Program.[484] As mentioned in the previous section, landowners should also verify the location of all old water wells and pits on their property and check they have been properly decommissioned.[485] Alberta Environment maintains well records and can provide information on registered water wells.[486]

The issue of water well maintenance is addressed in section 6.3.1.

6.2.6 Drilling wastes

The EUB has various provisions for the disposal of drilling fluids, depending on the substances used. Landowners might want to consider the points raised in section 4.2.1 with respect to the disposal of drilling wastes on their land. As explained in that section, allowed on-site and off-site disposal practices are based on "loading rates," which are estimates of the amount of waste the environment can handle without irreparable damage occurring. The Pembina Institute suggests it is preferable for drilling mud to be taken to an approved waste disposal site to avoid any problems. Any landowner who decides, despite the Pembina Institute's recommendation, to allow drilling wastes to be spread on his or her land, may want to negotiate additional clauses in his or her lease agreement to ensure extra protection for water bodies. This might relate to the timing of operations (e.g., not spreading the waste when the ground is very wet) as well as to setback distances.

6.2.7 Produced water

When discussing plans for a new gas well, it is a good idea for landowners to find out if the well will produce water and whether that water will be fresh or saline. If a CBM well is drilled into a water-bearing coal seam, this water will be pumped out immediately. The landowner should inquire about the volume of water that is expected and the duration of dewatering. It is a good idea to discuss how the water will be handled. If it is saline, will it be tanked or piped for re-injection. Where will the injection well be located? If the water is produced from above the base of groundwater protection, it may be possible to treat and use it. Sections 3.2.3.2 and 4.7 cover points that landowners may want to discuss with a company proposing to drill a new gas well.

With a conventional gas well, water will probably be produced as pressure falls after some gas has been produced. If gas is produced from shales, the amount and timing of water production may vary depending on the type of shale (see section 3.3.2).

6.2.8 Gas and water leaks

Some companies use pressure measurements in pipelines as well as visual surveys to indicate if there is a leak, but landowners who have wells or pipelines on their land may also want to be on the lookout for spills or leaks when working nearby. A very slow leak might not be apparent on the monitoring equipment but could do considerable damage if not detected. If a saline water leak from a pipeline is reported early, the area damaged may be limited. A fast gas leak will be registered on the monitoring equipment, but the location of a slow leak may be evident from

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[484] The Alberta Environmental Farm Plan Company. See especially Chapter 2 in the *Environmental Farm Plan Workbook,* http://www.albertaefp.com/program/progBinder.html

[485] Alberta Agriculture, Food and Rural Development. 2005. *Coal Bed Methane (CBM) Wells and Water Well Protection,* http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/eng9758

[486] The Groundwater Information System is online at http://www3.gov.ab.ca/env/water/groundwater/index.html Information can be obtained by telephoning Alberta Environment at 780-427-2770.

changes in the growth of plants nearby. If a leak is suspected, both the company and the EUB regional office should be notified immediately.[487]

6.3 Water wells

6.3.1 Troubleshooting problem water wells

Gas is sometimes found in water wells in Alberta. Gases may include odourless methane, carbon dioxide or nitrogen, and will be evident if they cause a spurting at the tap. Methane gas may be produced by bacteria that occur naturally in the aquifer or it may have migrated from somewhere else; in some parts of the province shallow gas may occur naturally in a formation. A "rotten egg" smell will warn of the presence of hydrogen sulphide gas (see section 6.3.2).[488] Water wells should be well ventilated to the outside, to ensure that there is no buildup of gas to explosive levels.[489]

Although landowners may suspect that seismic exploration or the drilling of a new gas or oil well has led to a problem in an adjacent water well, there are various reasons why a water well may give problems. Alberta Environment's investigations indicate that, in the majority of complaints it investigates, the cause is not due to oil and gas activity. Inadequate water well maintenance or the age of the well[490] is often determined to be the cause. If a landowner has a problem with a water well, a checklist in *Water Wells that Last for Generations* may help identify the problem.[491] Some information on water well maintenance is also provided in section 6.3.2, below.

Any landowner who suspects problems with a water well should take care to document all changes in his or her water, from the start of the problem until the investigation is complete.[492] It is important to include the date on all reports and photographs. Water samples are best taken by a qualified person who follows a recognized procedure (such as Alberta Environment's baseline water well testing protocol, see section 3.2.3.1). Expert help in taking the sample is especially important if the landowner wants to obtain an accurate measurement of any free (or dissolved) gas in the water well. The samples should be analyzed by an accredited laboratory. Landowners may wish to contact their local regional health authority to learn how to take their own water samples and have them analyzed. The health authority may conduct basic bacteriological testing (e.g., for *E. coli* and other bacteria) for a small fee to cover handling (e.g., \$ 5.00–\$ 10.00 per sample) or at no cost to the landowner. The regional health authority can help landowners interpret the results of any tests, whether from the landowner's sampling or that done by

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[487] The number for a regional office can be obtained by calling the government RITE line at 310-0000.

[488] Alberta Agriculture, Food and Rural Development. 1994. *Removing Hydrogen Sulphide Gas from Water,* *http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/agdex1160*

[489] Alberta Agriculture, Food and Rural Development. 2006. *Dissolved Gases in Well Water,* *http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/agdex637* See also *Water (Ministerial) Regulation, section 62,* *http://www.qp.gov.ab.ca/documents/Regs/1998_205.cfm?frm_isbn=9780779720699*

[490] Older wells tend to have metal casing that is susceptible to bacterial corrosion that will eventually lead to collapse.

[491] Alberta Agriculture, Food and Rural Development. 2001. *Water Wells that Last for Generations,* *http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/wwg404*.

[492] This includes noting the date and type of any change in water flow, colour or bubbling. Also note if there has been any change in the use of the water well. In some cases it may be possible to take photos to illustrate the changes. It can also be helpful to note the date of any seismic, drilling or fracturing activity in the vicinity of the water well and to check whether any neighbours have experienced problems.

industry, and provide an unbiased opinion on potability. However, the health authority does not usually test for other potential contaminants, such as gas or metals.

If a landowner thinks the water well trouble is related to seismic activity, then he or she should call the geophysical inspector (see section 6.2.1, above). If it might be due to an adjacent gas (or oil) development, the company should be informed and asked to investigate. Alberta Environment should also be informed of the problem, even if the company is investigating.[493] As explained in section 6.2.3, it is especially important to notify Alberta Environment before the company starts its investigation if the adjacent well is a CBM well where baseline water well testing was conducted. The nature of an investigation will vary depending on the problem. In some cases a company may conduct detailed testing. It should normally use the same protocols that are set out in Alberta Environment's requirements for baseline water well testing to ensure that the results are comparable. If a landowner negotiated a higher standard of baseline tests, all of the same tests should be repeated and the results compared.

When Alberta Environment investigates a water well complaint it may initially conduct bacteriological tests, and the outcome of those tests will determine whether additional testing is required.[494]

If a problem occurs with a water well and the landowner suspects that a company drilling a gas or oil well has caused the problem, he or she can ask the company to provide an alternative water source. If a company is unwilling to do this (perhaps because it does not think it has caused the problem), the landowner will need to find a new source while the problem is being investigated. In that case, the landowner should keep a record of all costs incurred, so he or she can seek reimbursement if the industry activity is shown to be responsible. As noted earlier, the Farmers' Advocate Office administers the Water Well Restoration or Replacement Program, which is designed to help a landowner who believes that his or her water well has been damaged by seismic or oil and gas activity.[495]

6.3.2 Landowner maintenance of water wells

It is not surprising that Albertans are concerned about the impact that gas development may have on the quality and quantity of fresh groundwater. They usually realize the importance of having good baseline data on water wells before an oil or gas well is drilled. However, it seems that not all landowners recognize that inadequate water well maintenance may cause or contribute to problems with water quality or quantity. In the mid 1990s, a survey of landowners in the Municipal District of Kneehill (which is located between Red Deer and Drumheller) showed that 74% of well-owners had problems with water quality, water quantity, or both.[496] The report

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[493] The Alberta Environment hotline at 1-800-222-6514 can be used to report problems.

[494] For additional information, see two Alberta Environment publications, released in 2006. *Water Well Investigations,* http://www.waterforlife.gov.ab.ca/coal/docs/Water_Well_Investigations.pdf and *Groundwater Protection and Coalbed Methane Development,* http://www.waterforlife.gov.ab.ca/coal/docs/Display_handout.pdf

[495] Farmers' Advocate Office, http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/ofa2621 Any landowner who obtains their water from a private, individual well can apply to the program. It is important to keep full documentation of any investigation and all receipts for any work done.

[496] Legault, Twyla. 2000. *Microbiological Activity and the Deterioration of Water Well Environments on the Canadian Prairies,* Prairie Farm Rehabilitation Administration, http://www.agr.gc.ca/pfra/water/swwi/iah2000t.pdf Water wells in the area are drilled into the Paskapoo Formation or the underlying Horseshoe Canyon Formation. High levels of bacteria were found, with two-thirds of the wells containing sulphate-reducing bacteria, and a smaller proportion containing iron-related bacteria or heterotrophic aerobic bacteria. In addition to lab tests for bacteria a video camera was used to examine the wells. They showed black and red slimes and biochemical encrustations of salts, such as sulphate, iron and manganese on the casing walls and intake areas. The report noted that the Horseshoe Canyon Formation seemed to provide an environment more conducive to the sulphate-reducing bacteria than the Paskapoo Formation. It was suggested that the formation underlying the Horseshoe Canyon

indicated that less than one-third of the water wells had ever been treated (with shock chlorination). It concluded that: "The relatively low percentage of treated wells clearly indicates that well owners do not recognize the role that preventative maintenance and treatment can play in improving or maintaining their water supply."[497]

Preventative maintenance and monitoring are essential for the sustainable management of a water well and will extend a well's life.[498] Maintenance includes keeping the well clean and ensuring there is no buildup of debris and organic matter. A water well should be checked for bacteria on an annual basis, to ascertain that the water is fit for human use. As mentioned earlier, this can be done through the local health authority. A routine chemical analysis is recommended every three to five years.

Bacteria, such as iron and sulphate-reducing bacteria, can build up in wells that are not properly maintained, resulting in slime growth. Sulphate-reducing bacteria may be associated with a rotten-egg odour caused by the formation of hydrogen sulphide.[499] There are routine tests for these substances, but testing is not usually conducted for gas in water wells. Thus, if a landowner suspects there is gas in a water well, he or she should ask for a separate test. The usual evidence of gas is spurting water at a tap that is turned on quickly after it has not been used for a while and a milky colour to the water during the first few seconds. The most likely gases in water when it foams are methane or carbon dioxide. A new test for methane has recently been developed and it has been suggested that there should to be a routine check for methane-producing and methane-consuming bacteria in Alberta, since these are the two major challengers to the life span of a well.[500]

People who have methane in their water well may be told about other substances in their well and wonder if there is a relationship. For example, is there any link between the presence of sulphate-reducing bacteria and the occurrence of methane in a well? Sulphate-reducing bacteria are often found in groundwater across Alberta. They interact with other bacteria and their prevalence varies. If there is methane in the groundwater (which most likely occurs naturally in the aquifer but might have originated elsewhere and migrated into the groundwater) the sulphate-reducing bacteria and the methane bacteria will "fight for the fatty acids," as is explained in the footnote.[501] This will often reduce the methane levels in the groundwater, as was indicated by a study in the Lloydminster area.[502]

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aquifer contained gas, which might be permeating into the water, with the methane providing a food for the sulphate-reducing bacteria. The study did not mention the fact that the methane could be coming from coal in the Horseshoe Canyon Formation itself. In the mid 1990s there was less awareness about natural gas in coal seams.

[497] Legault, Twyla. 2000. *Microbiological Activity and the Deterioration of Water Well Environments on the Canadian Prairies*, Prairie Farm Rehabilitation Administration, p. 6, *http://www.agr.gc.ca/pfra/water/swwi/iah2000t.pdf*

[498] This point is emphasized by Dr. Roy Cullimore, who has several useful publications on his web site at *http://www.dbi.ca/Books/* For a general overview (using examples from the U.S.) see Gorody, Anthony W. 2005. *What's in Your Water Well?* Presentation at the Northwest Colorado Oil and Gas Forum, November 18, slide 51, *http://www.oil-gas.state.co.us/Library/library.html* or *http://www.oil-gas.state.co.us/Library/WHAT%20IS%20IN%20YOUR%20WATER%20WELL.pdf*

[499] Cullimore, Roy. Undated. *Practical Manual of Ground Water Microbiology*, p. 70, http://www.dbi.ca/Books/ New edition expected spring 2007.

[500] Roy Cullimore, personal communication with Mary Griffiths, September 25, 2006. Dr. Cullimore has developed a number of parented BART™ tests for substances in water wells, which are widely used. The HAB-BART tests for methane-consuming bacteria and the recently developed MPB-BART tests for methane. BART stands for biological activity reaction test. For information on BART tests see *http://www.dbi.ca/BARTs/Docs/FAQ.html*

[501] When the sulphate-reducing bacteria (SRBs) and methane bacteria "fight for the fatty acids" the SRBs will win when the reduction oxidation potential is quite high (between minus 150 and plus 50 millivolts), but when the reduction oxidation potential is very low (less than minus 200

If a well is contaminated with harmful bacteria such as fecal coliforms, as the manual *Water Wells that Last for Generations* explains, they can be controlled by shock chlorination. It is essential for this process to be done very carefully, following expert instructions and using the most up-to-date information on chlorine concentrations.[503, 504] This means ensuring not only that the right amount of chlorine is used, but also that the pH level is kept at 4.5 to 5. The pH can be lowered by the addition of an acid.[505] In an old well that has not been routinely maintained and where there has been a buildup of debris and organic matter, the well should first be cleaned as some of the chlorine may be neutralized by the oxidation of dead material in the well.[506] Chlorine also has difficulty penetrating the biofilm (slime) structure around bacteria, so while it will reduce the problem somewhat, some bacteria such as sulphate-reducers are likely to remain at lower populations.[507] A new class of chemicals, called biodispersants, should thus be added to the well treatment solution to break up the bacteria that form common slime and enable the chlorine to properly disinfect the well.[508]

One other issue sometimes arises with respect to chlorination. There is a concern that "chlorine, in reacting with organic compounds, can generate trihalomethanes (THM), which may then enter the product waters. These THM compounds pose a health risk to the consumer when present in significant concentrations."[509] This could certainly be a problem if water that has naturally high organic levels (e.g., water from a dugout) is treated for drinking water purposes, as the level of THMs could exceed new standards.[510] THM generation can occur where chlorine is added to water continually and not properly monitored. If shock chlorination is conducted properly, it is not an issue. If chlorine is used in a water well, it is important to follow instructions about pumping off water to remove as much of the chlorine as possible before any water is used. It is advisable to ensure that water meets the *Canadian Drinking Water Quality Guidelines.*[511] The

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millivolts) the methane producing bacteria will out-compete the SRBs. Roy Cullimore, personal communication with Mary Griffiths, July 17, 2006.

[502] Van Stempvoort, Dale, Harm Maathuis, Ed Jaworski, Bernhard Mayer and Kathleen Rich. 2005. "Oxidation of fugitive methane in ground water linked to bacterial sulfate reduction" in *Ground Water,* Vol. 43, Issue 2, p. 187-199. Abstract at *http://blackwell-synergy.com/doi/abs/10.1111/j.1745-6584.2005.0005.x* This paper, which describes a study of private water wells in the Lloydminster area along the border between Alberta and Saskatchewan, "indicated a marked inverse relationship between the concentrations of sulfate and methane in ground water." Citation from page 188. The paper says there is "strong evidence that sulfate-reducing bacteria can play an important role in the biodegradation and natural attenuation of fugitive natural gas in ground water under cold temperature (~5°C) conditions." Citation from page 197.

[503] Alberta Agriculture, Food and Rural Development. 2001.*Water Wells that Last for Generations,* Module 6. *http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/wwg404* Recently, the concentration of chlorine that should be used for shock chlorination was revised to between 50 and 200 milligrams per litre of water. If the chlorine concentration is too high, it actually causes some bacteria to survive the treatment (as the slime-forming bacteria "melt" into a chemical gum that guards the bacteria from the chlorine).

[504] For detailed information on water well maintenance, including biofilms and proper chlorine concentrations see: John H. Schneiders. 2003. *Chemical cleaning, disinfection and decontamination of water wells.* Johnson Screens, Saint Paul, Minnesota. *http://www.weatherford.com/weatherford/groups/public/documents/johnsonscreens/js_books.hcsp?js=1*

[505] Many acids are suitable to lower the pH, including hydrochloric, phosphoric and even acetic acid (vinegar) on small well applications. The reason for maintaining the pH is to ensure that the hypochlorous ion (which is 100 times more biocidal than the hypochlorite ion) dominates. Alec Blyth, Alberta Research Council, personal communication with Mary Griffiths, January 2, 2007.

[506] Cullimore, Roy. *Practical Manual of Ground Water Microbiology,* p. 87, http://www.dbi.ca/Books/ New edition expected spring 2007.

[507] Cullimore, Roy. *Practical Manual of Ground Water Microbiology,* p. 71, http://www.dbi.ca/Books/ New edition expected spring 2007.

[508] A study by Alec Blyth, Alberta Research Council, found that the slime-forming bacteria remained after the standard chlorine treatment. With the addition of the biodispersant, these bacteria were removed. Alec Blyth, personal communication with Mary Griffiths, January 2, 2007.

[509] Cullimore, Roy. *Practical Manual of Ground Water Microbiology,* p. 87, http://www.dbi.ca/Books/ New edition expected spring 2007.

[510] Williamson, Ken. 1993. "What Do You Get When You Cross Dugout Water with Chlorine?" *Prairie Water News, Vol.3, No. 2, Fall 1993. http://www.quantumlynx.com/water/back/vol3no2/v32_st2.html*

[511] Acceptable quantities of substances in drinking water are set out in the *Canadian Drinking Water Quality Guidelines, http://www.hc-sc.gc.ca/ewh-semt/pubs/water-eau/doc_sup-appui/sum_guide-res_recom/index_e.html*

current guidelines set a maximum level of 100 parts per billion (or 100 micrograms per litre (=100µg/l) for THMs.[512]

Landowners wanting to find out more about groundwater in their local area can check if a regional groundwater assessment has been carried out for their municipal district or county.[513] Anyone wanting to learn more about water well testing may be interested in the field manual that is written for health inspectors.[514]

> Records of baseline conditions are essential, and landowners should carefully keep records of all meetings and actions by government and industry in case a problem arises. If there are problems, it is important to note the date of all events and to include the date on any photographs that are taken.

[512] Health Canada. Updated 2006. *Guidelines for Canadian Drinking Water Quality. Trihalomethanes,* http://www.hc-sc.gc.ca/ewh-semt/pubs/water-eau/doc_sup-appui/trihalomethanes/guide_e.html#t The Canadian limit of 100µg/l is higher than the U.S. standard of 80µg/l.

[513] Regional Groundwater Assessments have been carried out in many Alberta counties and municipal districts in conjunction with the Prairie Farm Rehabilitation Administration. The reports can be accessed on the web site of Hydrogeological Consultants Ltd. at http://www.hcl.ca/reports.asp The reports are based on information from the groundwater database which, as the report recommendations point out, has its limitations. However, the reports provide a general overview at a local level.

[514] Alberta Health and Wellness. 2004. *Environmental Public Health Field Manual for Private, Public and Communal Drinking Water Systems in Alberta,* http://www.health.gov.ab.ca/resources/publications/Environmental_drinking_water_manual.pdf

7. Recommendations to Government

Landowners recognize that it is imperative to protect fresh groundwater, which is essential for rural living and their agricultural operations. They believe that the government is more willing to accommodate requests from industry than to listen to those who live on the land. If they have a problem with a well, they often feel that investigations are too slow and that the burden of proof is on them to show if a problem was caused by industry, rather than vice versa. Some landowners are extremely frustrated with the requirement that the company they suspect of causing a problem with a water well is the same company responsible to oversee and directly pay for the cost of an investigation. This has led to the suspicion that industry and government are in collusion. In addition, despite early outcries of concern, landowners saw the rapid development of CBM for four years, before there was any baseline information against which to measure potential impacts. They found that, except for CBM, Alberta Environment does not routinely require a company to seek permission to divert fresh water produced with conventional natural gas, although since November 2006 the EUB has required companies to limit the production of fresh water from above the base of groundwater protection.[515] Some landowners worry that the density of wells being drilled, in combination with shallow fracturing operations, will impact fresh aquifers, especially as they realize that industry is still learning about the way in which shallow fractures develop. They feel that the government has been slow in addressing their concerns.

Many of the early landowner concerns were captured in the MAC's Final Report.[516] Fortunately, the government plans to implement all the recommendations that relate to the production of CBM, but it will take time.[517] Meanwhile, several thousand CBM wells are being drilled each year and landowners are just beginning to understand the true impacts. In addition, wells are being drilled for shale gas, about which there is not yet sufficient information for landowners to form an opinion. Alberta is underlain by extensive shale deposits, but the public does not yet know which zones will be productive and be developed, and, since the EUB does not have a separate classification for gas from shale, landowners cannot find out where or how many shale gas wells have been drilled. It has been suggested that shale gas development is at the same stage that CBM had reached five years ago. It is not known to what extent the U.S. experience with shale gas, such as the use of fresh water for fracturing the formations or the production of fresh or saline water from shales, will be relevant in Alberta. It is now time to review existing regulations to see if they need modification to minimize the impacts from shale gas development. Informed landowners believe that some new regulations that apply to CBM (which are in addition to the regulations that apply to all types of natural gas) should also apply to shale gas.

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[515] Alberta Energy and Utilities Board. 2006. *Directive 044: Requirements for the Surveillance, Sampling and Analysis of Water Production in Oil and Gas Wells Completed Above the Base of Groundwater Protection,* http://www.eub.ca/docs/documents/directives/directive044.pdf

[516] Government of Alberta. 2006. *Coalbed Methane/Natural Gas in Coal Multi-Stakeholder Advisory Committee Final Report,* http://www.energy.gov.ab.ca/docs/naturalgas/pdfs/cbm/THE_FINAL_REPORT.pdf

[517] Government of Alberta. 2006. *Report provides blueprint for responsible coalbed methane development,* news release, May 11, http://www.gov.ab.ca/acn/200605/1986224903061-BAA7-A9D2-840E8D7FBFCE213C.html Work on 32 of the 44 recommendations started in the 2006-2007 fiscal year. No action is being taken on two recommendations relating to royalty and tax adjustments.

Like CBM and shales, development of tight gas may also require a high well density in some regions, which again may have a greater impact on water than conventional operations.

Based on the learning from CBM, we urge the government to show landowners that it has the will and ability to protect Alberta's water resources and ensure they are managed in a sustainable manner for future generations. We believe that the following recommendations will help achieve this. Although this report is concerned only with the impacts of gas production on water, some of these recommendations are applicable to all other activities that affect water (whether due to industrial, municipal, agricultural or domestic water use).

7.1 Adopt the precautionary principle to protect fresh aquifers

A precaution is "an action taken in advance to avoid danger, prevent problems, etc."[518] The precautionary approach or precautionary principle "recognizes that the absence of full scientific certainty shall not be used as a reason to postpone decisions when faced with the threat of serious or irreversible harm."[519] The precautionary approach may involve measures to prevent serious problems from occurring and it can put the burden of proof on those who advocate taking action which is potentially harmful.[520] The government has various regulations and policies in place to reduce the risk to fresh aquifers, but the following recommendations propose additional precautions.

Ensure protection of deeper aquifers for future generations.

At present Alberta Environment regulates groundwater containing less than 4,000 mg/l TDS to maintain supplies and quality for human use. The U.S. has much more stringent standards and protects certain underground sources of drinking water with up to 10,000 mg/l TDS. The EPA notes that, "Although aquifers with greater than 500 mg/l TDS are rarely used for drinking water supplies without treatment, the Agency believes that protecting waters with less than 10,000 mg/l TDS will ensure an adequate supply for present and future generations."[521] In anticipation of climate change and increasing demands for water, the Alberta government should extend the protection of groundwater to sources with up to 10,000 mg/l TDS.[522] In the past it was not feasible to treat and reuse brackish waters with levels of TDS much in excess of 4,000 mg/l, but "Today, such waters are routinely desalted and have become important sources of supply in many regions of the world. Indeed, groundwaters between 4,000 and 10,000 mg/l have become an important global resource because they can be economically treated for domestic and other uses. Given the potential for heavy demands on water in the future it would be advisable to

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[518] Barber, Katherine. Editor. 1998. *Canadian Oxford Dictionary*. Oxford University Press.

[519]Environment Canada. 2001. *A Canadian Perspective on the Precautionary Approach/Principle*, http://www.ec.gc.ca/econom/pp_e.htm

[520] Wikipedia. 2007. *Precautionary Principle*, http://en.wikipedia.org/wiki/Precautionary_principle

[521] U.S. Environmental Protection Agency. 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Underground Coalbed Methane Reservoirs*, Executive Summary, p. E-1. "A USDW is defined as an aquifer or a portion of an aquifer that: A. 1. Supplies any public water system; or 2. Contains sufficient quantity of groundwater to supply a public water system; and (i) currently supplies drinking water for human consumption; or (ii) contains fewer than 10,000 milligrams per liter (mg/l) total dissolved solids (TDS) and B. Is not an exempted aquifer. .http://www.epa.gov/safewater/uic/cbmstudy/pdfs/completestudy/es_6-8-04.pdf

[522] The Pembina Institute first recommended that the government consider extending the protection zone up to 10,000 mg/l TDS in 2003 in *Unconventional Gas: the Environmental Challenges of Coalbed Methane Development in Alberta*, p. 53, section 7.4.1 http://www.pembina.org/energy-watch/doc.php?id=157

expand the definition of regulated groundwater in Alberta so as to ensure that all waters with economic value are regulated."[523]

Restrict fracturing in fresh water aquifers.

No fracturing should be allowed in fresh water aquifers unless it can be shown exactly how far and in what direction fractures will propagate and there is conclusive evidence that shallow aquifers will not be impacted. What fracturing is permitted will depend on the outcome of the EUB's Shallow Fracturing Technical Review Committee. If any fracturing is allowed close to or above the base of groundwater protection, the EUB should check all substances used in fracturing fluids to verify that they are non-toxic. If requested, the company should be required to provide the landowner with a written list of all substances being used, and permit viewing of the MSDS.

Ensure no dewatering of fresh water aquifers.

Water should not be withdrawn from non-saline aquifers unless it can be shown that there is no risk of impact to water wells or future water supplies. This will require information on flows, rates of recharge, expected changes as a result of climate change, and so on, as well as a high-density monitoring system. An increase in monitoring wells (see section 7.2) and regular evaluation of all the data is needed as a basis for the sustainable management of fresh water aquifers and to ensure that no user or group of users (whether industrial, agricultural or domestic) is depleting an aquifer, irrespective of the purpose for which the water is withdrawn.

Restrict the commingling of gas.

Commingling of gas from different zones or formations should not be permitted if the gas is produced from shallow wells that are above the base of groundwater protection to avoid any potential for cross-flows of water. The current EUB requirements should be routinely reviewed to determine whether they are sufficiently protective.

7.2 Improve knowledge of fresh aquifers

Sound knowledge is the basis for wise management. While recognizing that several government departments and agencies have recently increased their efforts to learn about fresh groundwater, we believe that further initiatives are required. As stated at the recent Rosenberg International Forum on Water Policy, "better information about the threats to groundwater quality and quantity is needed as there is significant risk and uncertainty."[524] We recommend that the government take the following actions:

Make a commitment to provide adequate long-term funding to enable the sustainable, integrated management of Alberta's groundwater.

Continuous monitoring of fresh water aquifers is essential to identify any trends in water availability or quality and enable wise, sustainable management of groundwater resources. It is not sufficient to store the information in a good database; there must be sufficient staff to analyze

[523] The Rosenberg International Forum on Water Policy. 2007. *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta*, p.15, http://rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf For information on the Rosenberg International Forum on Water Policy see http://rosenberg.ucanr.org/index.html

[524] The Rosenberg International Forum on Water Policy. 2007. *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta*, p.13, http://rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf The citation is taken from a paragraph that refers to the impacts of oil sands, coal and coalbed methane.

the data and create policy based on their findings. This requires a long-term funding commitment. As the Rosenberg International Forum on Water Policy has pointed out, “because response times are often quite slow in groundwater systems, it is important and highly cost-effective to develop the capability to detect changes in water levels on a continuous basis, so that rates of water use may be adjusted, if necessary, to ensure that the supply is not depleted considerably before action is taken.”[525]

The next two recommendations in this section further explain why this long-term funding commitment is needed.

Increase the number of monitoring wells to assess changes in groundwater levels and quality.

Alberta Environment needs to increase routine monitoring of both groundwater levels and water quality. The inadequacy of the current monitoring system is discussed in section 2.4. The number of monitoring wells in areas where there is a high density of gas wells in shallow formations must be sufficient to provide early warning of any declines in aquifers, whether due to industrial or agricultural activity or climate change.[526]

In additional to routine monitoring, special studies are required to establish baseline conditions. In early 2006 Alberta Environment initiated a two-year study in partnership with the Alberta Geological Survey to determine the effects of CBM activity in the Ardley coal zone on groundwater quality and quantity. Similar work should be undertaken in any area where shallow CBM, shale gas or tight gas may be developed that could affect shallow aquifers.

Gain sufficient information on flows and recharge rates to enable water budgets to be established.

In addition to submitting monitoring results to a database, the information should be regularly analyzed to identify any trends or changes to the aquifers. This requires the “Creation of information products, such as water budgets, time series and maps.”[527]

Sufficient monitoring data are needed to enable the construction of reliable models to estimate the relationship between groundwater recharge and withdrawal. Water budgets (which include the relationship of surface flows and groundwater within an area) will show whether current allocations and unlicensed water uses are sustainable.

Local communities should be informed of any negative changes in groundwater levels or quality and the source of the problem must be sought. This will, at a minimum, entail reviewing all major water diversions and taking immediate action to protect the aquifer (e.g., cancelling licences to divert), long before any negative impacts start to affect the landowners in the area. New licences should not be issued unless there is sufficient groundwater recharge in an area to meet the cumulative, long-term demand.

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[525] The Rosenberg International Forum on Water Policy. 2007. *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta,* p.18, *http://rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf*

[526] In addition, the government should make every effort to find out how much water is actually being withdrawn for traditional agricultural use and household purposes across Alberta. Unless a survey has been conducted on actual use, data on licensed withdrawals should be combined with the volumes that registered and unregistered users are entitled to withdraw, to determine whether current allocations can be sustained.

[527] The Rosenberg International Forum on Water Policy. 2007. *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta,* p.19, *http://rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf* This report includes many other recommendations relating to monitoring and data management.

Alberta Environment's current requirements with respect to draw down must be reviewed in recognition of the fact that recharge rates may change as a result of climate change and population growth. At present Alberta Environment states that an operator must not draw down the water below the top of a confined aquifer, but this may not be adequate given anticipated changes.

Improve baseline water well testing

When Alberta Environment's system of baseline water well testing for CBM wells drilled above the base of groundwater protection was set up in May 2006, the department announced that it would strike a scientific review panel to review the results after six and 12 months. At the time of writing, the panel is examining the baseline water well testing results that have been collected in the first 6 months. The panel is also to review the actual baseline water well testing standard and the manner in which the baseline data are collected, stored and evaluated. Pembina recommends that the committee should not only review the data but also receive feedback from landowners and others, which Alberta Environment could collect and pass on to the panel.

To obtain reliable, comparable results from baseline water well testing, it is essential that the samples are taken as set out in Alberta Environment's protocol. This requires proper training. There have been reports that some operators taking water well samples are not using the correct procedures as they have not been fully trained or are not adequately supervised. This situation must be addressed.

Some experts would like testing to be required for dissolved gas, as well as for free gas, but this will definitely require proper training, the careful selection of equipment to ensure that the tests are reliable and sufficient capacity to analyze the results in a timely manner. There should be at least two baseline tests per well, preferably conducted in the spring and fall.[528] Baseline water well testing is currently required only for CBM wells that access gas above the base of groundwater protection. Some landowners would like this requirement to be extended to all oil or gas wells including those below the base of groundwater protection.[529]

One way to improve baseline information across the province would be to require a company to conduct baseline testing of at least one water well close to every new oil or gas well drilled, irrespective of the depth of the oil or gas well. The testing would be carried out by qualified, certified professionals, and would include testing for dissolved gas in addition to free gas. The tests would be conducted two or three times for the chosen well. The company would also be required to supply water and gas samples from their production well for comparative analysis. The results of the laboratory analysis should be available on a public database, in the same way as those from the CBM water well testing.

In some circumstances (for example, if there is no landowner well in an area or if adjacent landowners do not wish to have their water wells tested) it may be appropriate for the government to require a company to install a monitoring well to record any changes to groundwater as a result of drilling or removal of water from shallow formations. Alberta

[528] Wheatland Surface Rights Action Group. 2007. *Groundwater Supply Concerns regarding CBM Development, Wheatland County, Alberta.* Report prepared by Omni-McCann Consultants Ltd.

[529] Some landowners who live adjacent to a CBM well that is drilled above the base of groundwater protection, but beyond the basic 600 metre testing limit set out in Alberta Environment's protocol also want their water wells tested. If a landowner's well has not had baseline testing and there are later problems with the well, Alberta Environment may refer to the results from baseline testing on other water wells in the vicinity to help diagnose the problem.

Environment should ensure that its own monitoring network provides comparable information in areas where there is no oil and gas activity as, for comparative purposes, it is important to have information on isotopic characteristics of groundwater across the province – even where no oil and gas is being developed.

Irrespective of the system used, Alberta Environment needs sufficient staff to conduct random checks to ensure that baseline tests are conducted as set out in their protocol. There should be penalties for non-compliance.

Establish reference wells for gas and water characteristics in production zones

If gas is found in a water well, it is often necessary to know the composition of the gas and water from adjacent gas formations, in order to identify where the gas is originating. At present this information is not generally available to those who are investigating problem water wells, even though individual companies may have it. Also, once gas in a wellbore is commingled it is not possible to identify the characteristics of the different source gases.

To ensure that there is sufficient information to identify the source of any gas in water, we recommend that a reference well system be established. One reference well might be required for every one or two townships, where the gas and water from all gas and oil producing zones would be collected. More than one reference well might be required, since one well would probably not be producing from all zones. The composition of the gas (the relative volume of methane and higher hydrocarbons) and the isotopic characteristics of the gas and water from each zone should be analyzed and the information stored in a publicly accessible database. This should be managed by the Alberta Geological Survey or the EUB.

Ensure adequate information to change the onus of proof on landowners

Landowners with a problem water well, who suspect that the problem was caused by industry activity, often find that the onus of proof is on them. At present, it is almost impossible for the landowner to prove that the well was earlier satisfactory unless a baseline test has been conducted. Unless there is a comprehensive network of data that is accepted and used as a standard for local aquifer conditions and gas characteristics, such as suggested in the previous recommendations, many landowners will want their own water well tested, to provide a baseline, irrespective of the depth of the production well.

Given the finite nature of resources, the government and independent hydrological experts should work with landowners to determine which is the most acceptable method of ensuring that sufficient data are available for the effective investigation of water well problems. Until this has been done, companies should offer baseline testing of all water wells before drilling any type of well. This would identify any pre-existing problems in the water well and would assist landowners in meeting their burden of proof. Companies should be required to offer the same level of baseline tests that are mandated for CBM wells drilled above the base of groundwater protection. Since some pro-active companies already offer to do this, it will create a level playing field. It must be recognized that not every landowner will accept the offer, but many will realize that having a baseline test will help identify the cause, should there subsequently be a problem.

Every effort must be made to ensure that there is sufficient information to identify the source of any problems and if the problem is caused by oil and gas development, the landowner should be fairly treated.[530]

Require companies to submit their project plans and undertake environmental impact reviews before applying for individual well licences.

A clear and transparent process, which includes public participation and review, is very important to those who are affected by energy developments.

Wells and facilities have traditionally been approved one by one, but the cumulative impacts can be very significant. It is time to look creatively for ways to reduce those impacts and this can be done through project planning. The EUB recognized in 1991 that if a CBM 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."[531] However, although the EUB encourages project disclosure, it has never required an overall development plan for CBM. In 1993 the EUB indicated that companies applying to extract oil and gas in the southern part of the Eastern Slopes would be required to submit development plans (rather than a piece-meal or single-well approach) and carry out environmental assessments.[532] The EUB is conducting pilot projects on advance planning,[533] but it is time for project-based planning to become routine.[534]

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[530] Clearly it is best to ensure there is no damage to an aquifer, but landowners need assurance that if problems occur they will be addressed. In part of Montana a company is required to sign an agreement with the landowner, promising to drill a new well if a water well is impacted. See the Board of the Oil and Gas Conservation of the State of Montana. 1999. *Order No. 99-99 Final Coal Bed Methane Order for Power River Basin Controlled Groundwater Area*. Point 6 states: "Coal bed methane operators must offer water mitigation agreements to owners of water wells or natural springs within one-half mile of a CBM field proposed for approval by the Board or within the area that the operator reasonably believes may be impacted by a CBM production operation, whichever is greater. This area will be automatically extended one-half mile beyond any water well or natural spring adversely affected. The mitigation agreement must provide for prompt supplementation or replacement of water from any natural spring or water well adversely affected by the CBM project and shall be under such conditions as the parties mutually agree upon." *http://bogc.dnrc.state.mt.us/CbmOrder.htm*

See also Montana Department of Environmental Quality. 2006, *Montana Water Use Act, Controlled Groundwater Areas. http://www.deq.state.mt.us/coalbedmethane/Laws_regulations_permits.asp*

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

[532] Alberta Energy and Utilities Board. 1993. *Informational Letter IL 93-9: Oil and Gas Developments Eastern Slopes (Southern Portion).* Companies are also expected to minimize surface impacts by sharing data, using common roads, pipelines and utility right-of ways, etc. The EUB seems unwilling to implement this policy until after one or more exploratory wells have been drilled. In 2006 they refused to grant standing to those who could represent the public interest in this region and wished to contest an exploratory well in the Eastern Slopes. *Decision on Requests for the Consideration of Standing Respecting a Well Licence Application by Compton Petroleum Corporation, Eastern Slopes Area, http://www.eub.ca/docs/documents/decisions/2006/2006-052.pdf*

[533] Alberta Energy and Utilities Board. 2006. "Land Challenge Pilot Projects Planned for Innisfail and Carstairs Areas," *Across the Board*, October, p.1 and 3, *http://www.eub.ca/docs/products/newsletter/pdf/atb_october_2006.pdf*

[534] The geology and regulatory system in the U.S. differ from Alberta, so it is not possible to draw direct parallels. However, it is instructive to see the type of information that a company must provide prior to approval for a CBM project in part of Montana. See Board of the Oil and Gas Conservation of the State of Montana. 1999. *Order No. 99-99 Final Coal Bed Methane Order for Power River Basin Controlled Groundwater Area*. Point 4 states: "An application for public hearing to establish permanent spacing and field rules for a CBM development project must include such information as is customarily required for establishment of well spacing and field rules for conventional gas production. Applicants must also present at the hearing a field development plan including maps, cross-sections and a description of the existing hydrologic resources, including water wells or springs that may be affected by the project, and a copy of the water mitigation agreement being used or proposed for use in the project area. The applicant must provide an estimated time frame for development activities, a monitoring/evaluation plan for water resources in the project area, the proposed number and location of key wells which will be used to determine water levels and aquifer recovery data, and water quality information for target coal aquifers available at the time of hearing. The Board will publish its customary notice of public hearing; the applicant must provide actual notice as required in Section 82-11-141(4)(b), MCA, and must notify all record water rights holders within one-half mile of the exterior boundary of the proposed field area." *http://bogc.dnrc.state.mt.us/CbmOrder.htm* Examples of environmental assessments conducted by the Bureau of Land Management and Montana agencies can be found at *http://bogc.dnrc.state.mt.us/CoalBedMeth.htm* The decisions include requirements specific to local conditions.

Project-based planning and environmental assessments will have many benefits, as they will identify potential impacts and encourage the industry to find ways to minimize them before development starts. For example, in the environmental assessment, a company should identify all water bodies (including alluvial aquifers) and ways in which they will be protected. Sensitive areas should be off-limits and will require adequate set-backs. A public review of the assessment will provide an opportunity for landowners to identify any concerns that have been overlooked and suggest preferred alternatives.

Project-based planning should enable companies to work together to minimize the cumulative impacts. If several companies are operating in an area they may be able to cooperate on an assessment to minimize the reproduction of similar information. This approach will help identify ways in which water can be conserved (e.g., by using produced water as a source of water for enhanced oil recovery or other operations in a region). The EUB has encouraged the development of synergy groups in Alberta and various landowner groups have been formed in response to concerns about the impact of new developments. These groups should be given the opportunity to provide meaningful input before more detailed decisions are made.

7.3 Increase surveillance of industry operations

Require companies to indicate what substances are used for fracturing in shallow formations.

If the precautionary principle is not adopted and fracturing continues to be allowed above the base of groundwater protection, companies should be required to disclose what substances they are using in their fracturing fluids, so that the EUB, Alberta Environment and interested landowners can verify that they are not toxic. Such a requirement would allow easier identification of the chemicals to test for if water quality is compromised at a later date.

Increase the number of field inspections conducted by Alberta Environment.

Landowners feel strongly that increased compliance monitoring is imperative to the safety of rural water supplies. Alberta Environment does not seem to have sufficient staff to conduct random checks to ensure that companies are in compliance. Even when complaints are raised by landowners, the initial investigation relies on information submitted by the company. The public thus does not have confidence that the department is adequately protecting the province’s fresh water resources. Alberta Environment should not only increase its ability to conduct random audits in the field, but should also publish the results so that its activities are transparent.

7.4 Improve the system for investigating landowner complaints and objections

Investigate water well complaints more rapidly and provide an interim assistance program.

Some landowners have been very frustrated by the time it takes Alberta Environment to investigate water well complaints and to release its findings, once complaints have been investigated. It can sometimes take months for Alberta Environment to look for the cause of a water well problem. This may be due in part to insufficient resources to react as quickly as a landowner would like, and in part to the fact that it takes time using a steps-wise approach to

See also, as an example, Bureau of Land Management Wyoming. 2006. *Jonah Infill Drilling Project: Final Environmental Impact Statement,* especially Chapter 4, Environmental Consequences and Mitigation Measures and the Board’s *Record of Decision,* *http://www.wy.blm.gov/nepa/pfodocs/jonah* gather all the information for a thorough scientific investigation. In the meantime, landowners have no recourse and must meet all the costs they incur in providing their own alternate water resource. While the first step is to ensure that Alberta Environment has sufficient resources to conduct investigations and publish their results more quickly (while ensuring a high-quality scientific process), there is also a need for a program that will provide assistance to landowners while they await the completion of the investigation. We thus suggest that Alberta Environment might work with the Farmers' Advocate Office to set up such a program, with assistance from the EUB. This might be an extension of the current Farmers' Advocate Water Well Restoration or Replacement Program.[535]

Improve reporting on water well complaints and investigations.

At present Alberta Environment collects data independently in each of its three regions, and the way in which statistics are reported means that data from different regions may not be directly comparable. It seems, for example, that one region has not noted if complaints relate to adjacent oil or gas activity, while the others have done so. Thus, when the records are searched to determine the cause of complaints, the categories are not identical. The system of recording complaints, investigations and outcomes should be consistent across the province. Some information is available on request, but it should be routinely published in a clear and transparent manner on the Alberta Environment website, indicating the number and type of complaint (e.g., whether the person reporting the problem thought it might be related to oil and gas activity) and the result of the investigation (i.e., the cause of the problem and how it was resolved). It will be necessary to take into consideration privacy issues, as outlined in the *Freedom of Information and Protection of Privacy Act*, but providing the data by municipal area (e.g., county or municipal district) should be satisfactory. The same system should be used whether the initial complaint is received by Alberta Environment, the EUB, Alberta Sustainable Resource Development, the Farmers' Advocate or some other agency. A consistent system is essential to identify trends in the number of complaints and outcomes.

Review the determination of who is "directly affected."

Landowners presently have to show they are "directly affected" if they wish to object to the drilling of a gas well. At present the EUB may only consider those living within 100 metres of a new well to be directly affected. This is not enough when considering potential impacts on groundwater. If shallow groundwater is damaged, it is possible that it could impact landowners who reside several hundred metres or kilometres away. The EUB and Alberta Environment thus need to consider the potential range of impacts when determining who is directly affected. In some circumstances, especially if there is no landowner who is directly affected, it may be appropriate to allow a municipality or non-governmental organization to represent the broader public interest. This could be the case with respect to Crown lands.

[535] Farmers' Advocate Office, *http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/ofa2621* We recommend that interim assistance should be provided by a neutral body. If the cause of a problem is later found to be due to energy-related activities, that body can seek reimbursement from the company deemed responsible. In the past some companies were willing to provide assistance to landowners as a goodwill measure, even if they did not think they were responsible for the problem. However, they are increasingly reluctant to do this, due to liability issues.

7.5 Improve routine monitoring of water wells

As noted earlier, regional health authorities will analyze the bacteriological and chemical quality of well water, to ensure that the water is fit to drink.[536] However, the government could do more to encourage landowners to get their water wells tested. It is in the interest of those living in rural Alberta to maximize the life span of their water wells. Since methane-producing and -consuming bacteria are the two major challengers to the life span of a water well, it would be advisable to establish routine tests for these bacteria. This should be straightforward, using the appropriate biological activity reaction tests.[537]

7.6 Revise the Crown Mineral Disposition Review Committee

While many of the above proposals will help reduce impacts, there are locations where gas development is inappropriate. For example, in the southern Foothills of Alberta, the risk of impacting the headwaters of streams and rivers should be considered before issuing rights, especially if there is potential of damage due to seismic activity or fracturing. Once a company has paid for a lease, it is naturally very reluctant to forgo development and, while the EUB may set conditions on development, it very rarely prohibits the drilling of a well.

The Crown Mineral Disposition Review Committee[538] is a government body with representatives from various departments who inform Alberta Energy of any potential environmental impacts. Alberta Energy then makes the decision as to whether mineral rights are posted for sale. However, as has been pointed out by one lawyer, “this committee itself is utterly non-transparent. It seeks no public input and, to my knowledge, there is no public record of its deliberations, its final recommendations, or even the identity of its members. Worse yet, it has no legislative direction and even uncertain legislative authorization.”[539] The committee’s mandate should be revised to allow for public input and to make its operations transparent.[540] Allowing public input before mineral leases are issued could increase the certainty for industry and reduce later problems.

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[536] See, for example, Calgary Regional Health Authority. *Drinking Water Quality*, http://www.calgaryhealthregion.ca/hecomm/envhealth/Drinking_Water_Quality/Drinking_Water_FAQ.htm#other%20testing

[537] Biological activity reaction tests (patented as BART tests) are now available for methane producing bacteria. The HAB-BART (for heterotrophic aerobic bacteria) will identify those bacteria that consume methane. Roy Cullimore, personal communication with Mary Griffiths, September 24, 2006. See http://www.dbi.ca/BARTs/HAB.html

[538] Alberta Sustainable Resource Development. *Crown Mineral Disposition Review Committee*, http://www.srd.gov.ab.ca/land/u_oilgas_exp_cmdrc.html

[539] Wenig, Michael. 2003. *Law Now*, December 2003-January 2004. “Who Really Owns Alberta’s Natural Resources?”, http://www.ucalgary.ca/~cirl/pdf/2003fDecJanWenig.pdf#search=%22Alberta%20Crown%20Mineral%20Disposition%20Review%20Committee%22 For more detail see Wenig, Michael and Michael Quinn. 2004. “Integrating the Alberta Oil and Gas Tenure Regime with Landscape Objectives – One Step Toward Managing Cumulative Effects”, p. 27–39 in *Access Management: Policy to Practice*. H. Epp, ed. Proceedings of the March 16-18, 2003 Alberta Society of Professional Biologists Conference, Calgary, Alberta. Alberta Society of Professional Biologists, PO Box 21104, Edmonton AB T6R 2V4.

[540] Some landowners would like to be notified when mineral rights under their land are posted for sale. They think that notification at the sale of lease will give more time to identify cumulative impact concerns (how many wells/surface locations were already in place and how many more locations were tolerable, based on current and future land use). The current level of surface impacts may help a company identify lands were potential conflicts with the surface owner may occur and ascertain the likelihood for ease of access.

7.7 Increase the resources available to Alberta Environment and EUB and improve their accountability

Earlier recommendations refer to the need for more resources for monitoring, data management and so on. Here we look at the broader need for resources and reporting on activities.

There are some good, dedicated staff at Alberta Environment and the EUB, but there is a wide perception that they do not have enough resources to fulfill their mandate. Certainly, additional resources will be needed if the recommendations in this chapter are to be implemented. Within Alberta Environment, the budget and number of staff have not increased to keep pace with the rapid growth in industrial activity. Indeed, industrial expansion has drawn many experts (including hydrologists) from government into the private sector; experts may be replaced with junior staff with less experience. Even when the department makes a commitment to improve water management, the changes may take many months or years to implement. While some improvements to data management systems have been made, more needs to be done.

The EUB may also need to increase its capacity, but at least it provides a clear annual overview of inspections and compliance. Each year, the board issues a timely report on its surveillance operations, showing the number of inspections and enforcement actions relative to the total number of wells, pipelines and facilities.[541] It is thus possible to monitor whether industrial compliance in a particular sector is improving.

Within Alberta Environment, there is not the same level of routine public reporting and information is sometimes only made available as a result of a specific request. Some landowners have complained that investigations have been slow, and that too much reliance is placed on information provided by industry. The department needs the resources to independently verify information on a random basis and to make the results of all its surveillance activities public in a report published within six months of year-end. Also, the methods used by Alberta Environment for water management and planning should be open to scrutiny, to ensure that the best techniques are being used, e.g., in modeling the recovery of aquifers. Since the department has historically over-allocated water in the South Saskatchewan River Basin, it is not surprising that the validity of its processes is now in question in other areas.

7.8 Review resource allocation and management in Alberta as it impacts water

This final recommendation, to review resource allocation and management is not specific to natural gas or water, but it aims to address a major deficiency in the current system of resource management. The cumulative impacts of all oil and gas developments, combined with all the other increasing pressures on land and water resources, need to be addressed. The issues that need to be considered with respect to land use planning are also applicable with respect to water and gas.[542] Including water in a high-level review of resource allocation priorities would ensure a fully integrated approach to resource management in the province.

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[541] Alberta Energy and Utilities Board. 2006. *ST 99-2006: Provincial Surveillance and Compliance Summary 2005,* http://www.eub.ca/docs/products/STs/st99_current.pdf

[542] Kennett, Stephen A., 2006. "A Checklist for Evaluating Alberta's New Land-Use Initiatives" *Resources,* Number 95, Summer 2006, p. 5. Canadian Institute of Resources Law.

Thus we recommend that the Alberta government set up a process to review and revise resource allocation and management in Alberta as it impacts water. This review could, potentially, become a new element in the broad review of integrated land management that is currently being planned by Alberta Sustainable Resource Development. Consideration of water resources should be an essential element in sustainable land use planning, not only at a provincial but also at a regional level.

This recommendation addresses the need for a reassessment of the principles underlying the allocation of scarce resources. In the past a prime goal has been the production of natural gas and other energy resources, with regulatory controls focused on limiting (but not preventing) impacts on landowners and the natural environment. However, with an increase in the number of wells and the growing pressures on agricultural land, natural ecosystems and water resources, it is important to determine which uses should have the priority in a given area. Alberta Energy has traditionally made the decisions on lease allocation but "Alberta Energy's sale of mineral rights occurs without clear policy and planning guidance on landscape-level objectives and trade-offs."[543] This statement about land applies equally to water resources. The EUB Land Challenge Pilot Projects mentioned earlier provide an opportunity for advance planning on a township basis, but they focus on orderly development rather than whether development should actually proceed in a certain location.[544] The Alberta Water Council and the Watershed Planning and Advisory Councils have been set up to look at the broader issues relating to water allocation and management, but it seems they will have to work with the status quo as far as energy leases and activity are concerned. It would be wise to align land use planning activities on a watershed basin, at some level, to ensure land use developments remain in line with the available water resources.[545]

7.9 In conclusion

The government has recognized that the development of unconventional gas resources imposes new impacts on landowners and the environment. It has worked with industry and those who represent the interests of landowners to recommend improvements for the management of CBM, but it will take time before all the recommendations are implemented. In the meantime, an increasing number of gas wells are being drilled each year in an effort to slow the decline in gas production in Alberta. The cumulative increase in the number of wells impacts landowners, whether these wells are for CBM, shallow gas, tight gas, shale gas or conventional natural gas. Landowners are becoming much more knowledgeable and definitely more vocal about these impacts. The protection of fresh water, especially groundwater, is one of their chief concerns and has been addressed in this report. However, there are also many other impacts on the land surface and on the quality of rural life that the government needs to address in a proactive and timely manner.

We hope that the collaborative approach and opportunity for public input seen, for example, in the MAC, will be continued and expanded to address new challenges as they arise. Most

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[543] Kennett, Stephen A. and Michael Wenig. 2005. "Alberta's Oil and Gas Boom Fuels Land-Use Conflicts – But Should the EUB Be Taking the Heat?" *Resources,* Number 91, Summer 2005, p.5. Canadian Institute of Resources Law.

[544] Alberta Energy and Utilities Board. 2006. "Land Challenge Pilot Projects Planned for Innisfail and Carstairs Areas", *Across the Board,* October, p.1 and 3, *http://www.eub.ca/docs/products/newsletter/pdf/atb_october_2006.pdf*

[545] The boundaries of groundwater areas do not correspond exactly with surface watersheds, but the proposed approach would help ensure that water availability is addressed in the land use planning process.

landowners recognize the need for oil and gas development, and are willing to work with government and responsible companies towards extraction of the resource if water is effectively protected and if new challenges are quickly addressed as they arise. In the meantime, it is important for the various government departments and agencies to be given the resources they need to respond to the issues that have been identified in this report and to implement the recommendations. A clear and transparent process, which involves all the stakeholders affected on an equal basis, is key to continued success with respect to the development of Alberta's gas and oil resources.

Appendix A: Gas Composition and Isotopic Analysis

The analysis of gas composition and the isotopic characteristics of the gases can help identify the source of gas found in a water well. It is a complex subject but this appendix attempts to set out some of the basic principles.

There are two main types of methane found in rock formations and groundwater:

1. Thermogenic methane, which is formed from buried organic matter at considerable depths where the rocks are compressed and heated; this includes the methane found in coals.
2. Bacterial methane formed closer to the surface by the action of bacteria.[546]

Gas formed by thermogenic processes contains small amounts of ethane and propane (and may contain very small amounts of butane and pentane) as well as methane. Coals may contain these substances, even at relatively shallow depths.[547] When bacteria generate "biogenic" gas, they create mainly methane.[548] The source of natural gas in the earth can to some extent be determined by the relative proportion of methane, ethane and propane within the gas.[549] Even very small amounts of ethane and propane may be important in helping to identify the source of the gas.[550] This is referred to as gas composition analysis. Unfortunately, gas composition analysis is very complicated as thermogenic and biogenic gases may be altered after they have been formed (see below). This affects the relative proportions and isotopic composition of the gases, thus making it more difficult to distinguish them.[551]

It would be helpful to have the exact proportions of ethane and propane when analysing samples from water wells, to help distinguish between any gas that may originate from the aquifer (due to microbes in the water that create biogenic gas[552]) and any CBM or shale gas that may have

[546] More detailed information can be found in Rice, Dudley D., 1993. *Composition and Origins of Coalbed Gas.* AAPG Studies in Geology No. 38, p. 159-184, *http://www.searchanddiscovery.net/documents/rice/index.htm*

[547] However, the proportions may vary and the carbon isotope ^{13}C shows more methane, relative to the ethane and propane gases where the methane is "mature". This is usually at greater depths, that is, greater than 2,000 to 3,000 metres.

[548] Bacteria may also create minute amounts of ethane. Pure biogenic methane will have very low carbon isotope values.

[549] Methane, which is shown by its chemical composition CH_4, is composed of 4 hydrogen atoms linked to one carbon atom. Ethane (C_2H_6) has two carbon and six hydrogen atoms; propane (C_3H_8) and butane (C_4H_{10}) have even more atoms. These gases are sometimes referred to as the higher hydrocarbons as they have more carbon and hydrogen atoms than methane.

[550] Some people wonder why attention is paid to small amounts of propane and ethane, but they can be important in helping to distinguish different sources (e.g., for fingerprinting gas from shallow coals). Using a somewhat domestic analogy, one might think of baking cookies or cakes. The main ingredient is flour and only a very small amount of spice such as cinnamon or ginger may be added, but it is that spice that gives the characteristic flavour to the cinnamon bun or gingerbread.

[551] Thus, deeply buried gases can become overcooked and may "crack". This greatly increases the ^{13}C values and changes the relative proportions of ethane and propane. Microbial alteration of gases will selectively enrich the ^{13}C in ethane and propane. At the same time it will produce low ^{13}C values of methane.

[552] Microbes in groundwater can generate methane by the reduction of carbon dioxide or by fermentation.

migrated into the aquifer. However, the total amount of ethane or propane may be very small, which makes it difficult for laboratories to get accurate measurements of their volume, unless the people taking the samples are extremely careful. Because analyzing samples for their gas composition is difficult and may not be conclusive, determining the source of a gas usually requires isotopic fingerprinting as well.

Methane is composed of carbon and hydrogen (as shown by its chemical annotation, CH_4, i.e., there are four hydrogen atoms linked to each atom of carbon). It is possible to establish "signatures" or "fingerprints" for a gas by analysing the isotope ratios of the carbon and hydrogen. Carbon has two stable isotopes: carbon 12 and carbon 13. Analyzing methane to determine the ratios of these two carbon isotopes can help to identify the source of the methane.[553] Hydrogen has two stable isotopes: hydrogen 1 and hydrogen 2; again, the ratio between these two can help in distinguishing different sources of methane.[554] A similar isotopic analysis can be conducted on ethane (C_2H_6) and propane (C_3H_8).

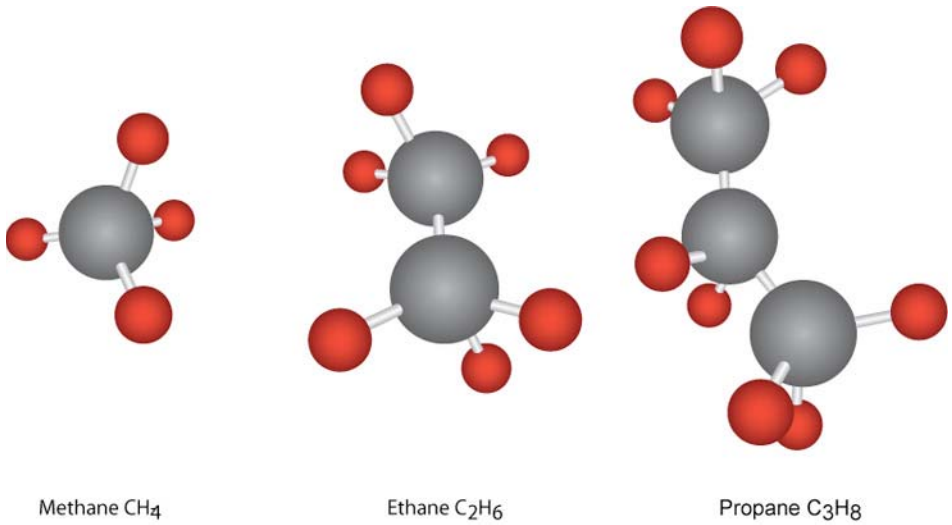

Figure A-1 The chemical composition of methane, ethane and propane

Before we go any further, a quick word about the way scientists express the isotopic characteristics of a gas. It's very complex, and here we give only a basic explanation to help readers understand the signs and symbols that are used in graphs showing data obtained from isotopic analysis. The stable carbon isotope ratio, which is the ratio of the two isotopes carbon 13 (written as ^{13}C) and carbon 12 (written as ^{12}C) compared with a standard ratio, is shown as a delta value (also written as δ), which is the abundance, expressed in parts per thousand ($^{O}/oo$). The full equation and further explanation is given in a footnote.[555]

[553] Approximately 1.1% of carbon atoms are carbon 13. Carbon 13 has an extra neutron in its nucleus, which makes it heavier and causes it to have different reaction rates with temperature.

[554] Stable isotope data are given as ratios, e.g., $^{2}H/^{1}H$ or $^{13}C/^{12}C$, rather than as absolute molecular abundances or concentrations. These ratios are expressed as the difference (in parts per thousand) between the measured value and a known standard isotope ratio. These ratios are shown by the delta symbol, δ. For a fuller explanation, see footnote on p. 193 of M.J. Whiticar, 1996. "Stable isotope geochemistry of coals, humic kerogens and related natural gases", *International Journal of Coal Geology,* Vol. 32, pp. 191- 215. This paper shows the complex nature of isotopic analysis.

[555] The equation is: $\delta\, ^{13}C\ ^{O}/oo = \frac{(^{13}C/^{12}C) - (^{13}C/^{12}C)_{PDB}}{(^{13}C/^{12}C)_{PDB}} \times 1000\ ^{O}/oo$

Now let's get back to the issue of gas in a water well. If there is gas in a water well, the relative proportion of methane to ethane and propane, and the isotopic analysis of the gases can help distinguish the source of gas. As described by one isotope laboratory, "biogenic [bacterial] gas typically has a high proportion of methane to ethane and propane, and a more negative methane-carbon isotope ratio. Thermogenic gas, in contrast, has a lower proportion of methane to ethane and propane, and a less negative methane carbon isotope ratio."[556] These differences are illustrated in the next two graphs.

Figure A-2 plots the carbon isotopes for methane and ethane in Alberta gas from different origins: thermogenic gas, biogenic (bacterial) gas from the Medicine Hat area and gases found in selected water wells in central Alberta. The data for water well gas is taken from a May 2006 baseline study and the data for production gas is from a University of Alberta database.

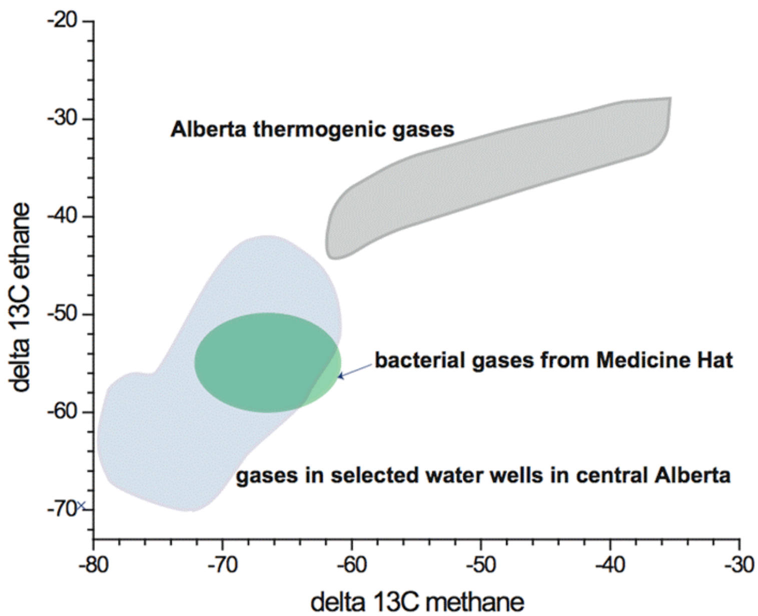

Figure A-2 Cross plot of carbon isotope values for methane and ethane in Alberta gases from differing origins

Source: Karlis Muehlenbachs, University of Alberta. See text for explanation.

Each gas sample has its own isotopic composition but gases from different sources usually have restricted values that fall into separate fields on this graph. Note how methane and ethane in gases from water wells have much less ^{13}C than thermogenic gases from deep conventional oil and gas wells. It can be seen that gases from the prolific but shallow gas fields near Medicine Hat have isotopic compositions indistinguishable from those of the water well gases; this indicates a similar, near surface origin.

If gas is found it a water well, its isotopic characteristics will be compared with gas in adjacent formations. However, the gas may be a mixture from more than one source. If gases from deep

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($^{13}C/^{12}C$) $_{PDB}$ is the carbon isotope ratio of the International Standard of Belemite Fossil from the Pee Dee Formation in South Carolina. This is the standard isotopic composition against which all other isotopic compositions are compared. The ratio usually gives a negative value, which means that there is relatively less Carbon 13 than Carbon 12.

[556] ZymaX Stable Isotope Laboratory. Undated. *Fugitive Methane, http://www.zymaxisotope.com/fugitivemethane.asp* See also *www.zymaxisotope.com*.

and shallow sources mix, they will follow predictable trends, as is shown in Figure A-3: Gas contamination in a water well.

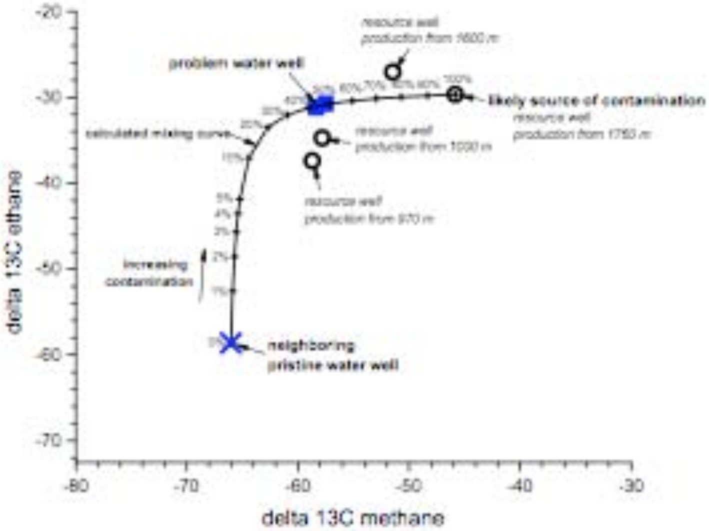

Figure A-3 Gas contamination in a water well

Source: Karlis Muehlenbachs, University of Alberta. See text for explanation.

Figure A-3 compares the carbon isotopic compositions of gas from several sources:

- A "problem water well" on a farm, which was sampled twice, six months apart. In addition to methane and ethane, it contained propane, butane and pentane, which indicates that some of the gas comes from a thermogenic source
- Four resource wells that produce natural gas and are located less than a kilometre from the problem water well
- Gas from a presumed pristine water well ten kilometres away.

The graph also shows a "mixing curve" that models how the isotope ratios of a gas change upon mixing two gases with differing isotope ratios as well as differing proportions of ethane.[557] All the isotope data can be explained if gas in the problem water well is an almost one-to-one mixture of typical shallow gas found in many water wells of Alberta (99.5% methane; 0.5% ethane) and resource gas from 1,760 m deep 78% methane and 13% ethane).

However, identifying the source of a gas is not always as straightforward as indicated in Figure A-3, as there is often some overlap in the characteristics of gas from the different sources and formations. Gas from the deep Mannville formation is altered thermogenic gas, but gas in the Horseshoe Canyon and Belly River formations may be thermogenic or biogenic.[558] Sometimes thermogenic gas is altered by biogenic processes while it is in the formation.[559] Also, both

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[557] This method is based on the work of Jenden, P.D., Drazan, D.J., Kaplan, I.R., 1993. "Mixing of thermogenic natural gases in northern Appalachian Basin". *American Association of Petroleum Geologists Bulletin 77*, p. 980-998.

[558] Mayer, Bernhard. 2006. *Assessment of the Chemical and Isotopic Composition of Gases and Fluids from Shallow Groundwater and from Coalbed Methane Production Wells.* June 21, Presentation to Petroleum Technology Alliance Canada Water and Innovation Conference, http://www.ptac.org/env/dl/envf0602p10.pdf Between April 2004 and June 2006, the Applied Geochemistry Group at the Department of Geology and Geophysics, University of Calgary examined more than 75 CBM wells and their findings suggest that gas in the Horseshoe Canyon formation is predominantly thermogenic in origin.

[559] Karlis Muehlenbachs, University of Alberta, personal communication with Mary Griffiths, July 22, 2006.

thermogenic and biogenic gases can be generated in shallow coal and shale.[560] As a result, isotopic analysis of water wells with coals in the completion interval may present a thermogenic signature.

To complicate matters still further, biogenic and thermogenic gas may undergo chemical and isotopic alteration as they migrate towards the surface. For example, methane may be oxidized in near-surface soils, which changes the carbon and hydrogen ratios of the remaining methane to less negative values, so they are closer to the isotope ratios of thermogenic methane. This naturally makes it more difficult to distinguish the two sources of methane. The next step is thus to look at the isotopic fingerprint of any ethane in the gas.

It may be possible to identify different sources of gas by studying the hydrogen isotopes in the water associated with the gas, in addition to the carbon isotopes. If water in the water well is different from water in the CBM well, it will have a different hydrogen isotopic fingerprint. This should also be investigated if an isotopic test is required after gas is found in a water well. The isotopic results from the hydrogen in the water well must then be compared with tests on the water in the CBM well.[561] Even in dry coals very small quantities of water will be released from cores taken from the coal. If tests taken after the drilling of a CBM well show that the isotopic fingerprint has changed, relative to the baseline testing, to become more similar to the fingerprint of the water from the CBM well, it is likely that the water well has been contaminated by the CBM activity. Baseline data from each producing zone in a CBM well and other gas producing formations should be collected when the gas wells are drilled. This is important, as it is often difficult to collect the data once a well is producing since gas is produced from several zones and then mixed or “commingled” in the wellbore. It is not possible to determine the isotopic characteristics of the various gases once they are commingled. However, hydrogen isotopic analysis may still not be conclusive and more work is needed on the use of hydrogen isotopes to differentiate methane from various sources.

As one researcher has reported, “Carbon isotope forensics is only possible if good background data is available.”[562] The University of Alberta is establishing a carbon isotope database of known production gases, isotope mud logs (that is, samples from the different zones/formations that have been drilled into) and migrating gases (from water well and surface casing vent flow samples sent for analysis).[563] However, far more information is required from each gas-producing formation. It is important to have isotopic data from all the zones in a reference well, from surface to depth. Samples from production zones or vent flows are not sufficient, since different formations at different depths may have very similar isotopic signatures. The reference well must be located in the area where there is a problem, so that the geology of the two wells is similar.

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[560] Karlis Muehlenbachs, University of Alberta, personal communication with Mary Griffiths, July 25, 2006.

[561] To get an idea of the complexity of analysis of methane in water compared with methane in coal seams, see Anthony W. Gorody, Debbie Baldwin and Cindy Scott. 2005. *Dissolved Methane in Groundwater, San Juan Basin, La Plata County Colorado: Analysis of Data Submitted in Response to COGCC Orders 112-156 & 112-157*, *http://ipec.utulsa.edu/Conf2005/Papers/Gorody_DISSOLVED_METHANE_IN_GROUNDWATER.pdf* This paper was presented at the 12th Annual International Petroleum Environmental Conference, 2005. See agenda at *http://ipec.utulsa.edu/Conf2005/2005agenda.html* A Power Point presentation is available at *http://www.oil-gas.state.co.us/Library/SanJuanBasin/SanJuanMethaneAnalysisFinal_files/frame.htm*

[562] Karlis Muehlenbachs. 2006. *A New Tool for the Industry: Estimating the Source Depth of Unwanted Gas by Carbon Isotope Fingerprinting.* Power Point presentation.

[563] Karlis Muehlenbachs, University of Alberta, personal communication with Mary Griffiths, July 25, 2006.

Even with detailed baseline information isotopic analysis may not be conclusive. For example, gas in an aquifer may be a mixture of local microbial (or biogenc) gas and gas migrating from a CBM formation or well. It will thus have a "mixed" fingerprint. A process called mass balance may then be used to help identify the source of the migrating gas. Using the known proportion of methane and ethane and their isotopic ratios in a given CBM formation and in local water without gas migration, a model will be designed to plot the carbon fingerprint of mixtures of the two gases, assuming different proportions in the mix. The isotopic composition of the sample will be compared with the various hypothetical alternatives, to find which one best fits the "mixed" signature.

While the analysis of problem water wells focuses on isotopes in free gas, work is underway to measure and analyze the chemical and isotopic composition of dissolved gas. The Alberta Ingenuity Centre for Water Research is financing a three-year project at the University of Calgary to research the chemical and isotopic characterization of shallow groundwater in the vicinity of CBM operations in east-central Alberta. This work aims to assess the technical feasibility to determine carbon isotope ratios of dissolved gases in groundwater and the sources of naturally occurring dissolved (and where available free) methane in shallow groundwater.[564] The Alberta Research Council is working on a small test project east of Red Deer to determine the applicability of hydrogen isotopes (in conjunction with carbon) in distinguishing gas sources.[565]

Gas composition and isotopic analysis is a very complex and expensive undertaking that continues to challenge academics around the world. Unfortunately there is no one method that can routinely determine where methane has originated. It is often necessary to examine gas compositions, perform isotopic analysis, and sometimes pursue other methods as well that are not discussed in this appendix (such as evaluating geochemical signatures).[566] Even after pursuing several analysis techniques there may still be uncertainty as to where the gas originated.

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[564] Mayer, Bernhard, 2006. "Assessment of the Chemical and Isotopic Composition of Gases and Fluids from Shallow Groundwater and from Coalbed Methane Production Wells", *2006 Water Innovation in the Oil patch Conference*, Petroleum Technology Alliance Canada, June 21-22, Calgary, *http://www.ptac.org/env/dl/envf0602p10.pdf* This project started in April 2006. At the time of this presentation only a few gas samples from shallow groundwater had been thoroughly analysed in east central Alberta, but those studied showed that there is often no free gas and the dissolved gas is partially or predominantly biogenic. Dr. Mayer is hoping to develop an accurate "finger-printing" tool for landowners, industry and regulators. "If this tool works, it will give them an accountable 'measuring stick' that tells them whether fluids or gases from CBM production have impacted an aquifer or not, and to what degree." *EnviroLine,* September 19 – November 14, 2006, Vol. 17, No. 1 & 2, p. 8.

[565] Alec Blyth, Alberta Research Council, personal communication with Mary Griffiths, September 11, 2006. Several residential water wells were tested for free gas and water in an area prior to CBM development. Gas was then sampled gas from two CBM wells being drilled. In one sample, drill cuttings from several individual zones within the Horseshoe Canyon and the Belly River were tested. In another, chunks of core were taken from the same zones. A third CBM well will be sampled that is being drilled with air. Later the produced water from all three CBM wells will be sampled (although as this water will be commingled, study criteria are not perfect).

[566] See, for example, Alberta Energy and Utilities Board/Alberta Geological Survey. 2007. *Water Chemistry of Coalbed Methane Reservoirs,* EUB/AGS Special Report 081, p. xvi, *http://www.ags.gov.ab.ca/publications/SPE/PDF/SPE_081.pdf*

Appendix B: Glossary

Abandonment (of wells)	Abandonment means converting a drilled well to a condition that can be left in safety indefinitely. In Alberta a well must be abandoned in accordance with EUB *Directive 20: Well Abandonment*, which includes measures to prevent cross-contamination between different producing formations, to protect fresh water and potential hydrocarbon reserves. After a well has been abandoned, the site can be reclaimed in accordance with Alberta Environment requirements.
Aquifer	An aquifer is a geologic unit that stores and transmits water to wells and springs. Use of the term is usually restricted to those water-bearing structures capable of yielding water in sufficient quantity to constitute a usable supply.[567]
Base of groundwater protection	The base of groundwater protection in Alberta refers to a depth of 15 metres below the deepest non-saline aquifer.[568] Water in a non-saline aquifer contains less than 4,000 mg/l total dissolved solids (see definition of saline water, below).
Casing	The casing forms a major structural component of the wellbore and serves several important functions: preventing the formation wall from caving into the wellbore, isolating the different formations to prevent the flow or crossflow of formation fluids, and providing a means of maintaining control of formation fluids and pressure as the well is drilled.
Commingling	In this report, commingling refers to the mixing of gas and/or water from different geological zones.
Cumulative impact	A cumulative impact is the effect of past, present and possibly future actions added together.
Drilling fluids (also called drilling mud)	These are the fluids used to cool the drill bit, bring drilling cuttings out of the wellbore, maintain hole stability and pressure, prevent fluid losses, and isolate zones of different pressures during the drilling process.
Energized fracturing	This is a system that adds a gas to the fracturing fluid (where the gas is up to 55% of the total volume).
Environmental assessment	A environment assessment is a public document that examines the possibility for significant environmental

[567] Alberta Environment. Undated. *Water. Learn about Water. Aquifers.* Alberta Environment uses the definition from the North American Lakes Management Society, *http://www3.gov.ab.ca/env/water/GWSW/quantity/learn/what/GW_GroundWater/GW4_aquifer.html*

[568] Alberta Energy and Utilities Board. 2006. *Directive 036: Drilling Blowout Prevention Requirements and Procedures*, p.86, *http://www.eub.ca/docs/documents/directives/Directive036.pdf* his reference refers to *ST55-Alberta's Usable Groundwater Base of Groundwater Protection Information*, which is not available online. ST55 indicates that the base of groundwater protection is the deepest non-saline aquifer or 600 metres below the surface, whichever is shallower.

	impacts from a course of action.
Fracturing	Fracturing is a method to improve the permeability of a reservoir by pumping fluids such as water, carbon dioxide or nitrogen into the reservoir at sufficient pressure to crack open the rock. Substances may be added to water to improve the effectiveness of the process and to hold open the crack, so that the gas can flow more easily to the wellbore.
Fresh water	In this report we use "fresh" to refer to water with total dissolved solids of 4,000 milligrams per litre or less.[569] This is also the definition of usable or non-saline water.
Gas migration	Gas migration is any movement of gas from one place to another, usually where this is unintended. The EUB defines gas migration as a flow of gas that is detectable at the surface outside of the outermost casing string (often referred to as external migration or seepage).[570]
Groundwater	Groundwater is water that exists under the surface of the Earth, usually held in the pores or permeable structure of rocks and sediments.
Hydraulic head	This is a specific measurement of water pressure that can be used to calculate the hydraulic gradient between two or more points. It indicates the potential for a fluid to flow, if a flow pathway is available.
Hydraulic fracturing	This involves pumping a fluid or an inert gas (usually nitrogen, in the case of dry CBM wells in Alberta) down an oil or gas well at high pressures for short periods of time (measured in minutes) to create or extend fractures in the reservoir rock, so that the oil or gas can flow more easily to the wellbore. The high pressure fluid (often water with some specialty high viscosity fluid additives) exceeds the rock strength and opens a fracture in the rock. A propping agent, such as sand carried by high-viscosity additives, is pumped into the fractures to keep them from closing when the pumping pressure is released.
Hydrocarbon	A hydrocarbon is an organic chemical compound consisting of hydrogen and carbon. Methane, ethane and propane are light hydrocarbons. Heavy oil and bitumen are heavy hydrocarbons.
Intermediate casing	There may be intermediate casing between the surface casing and the production casing (e.g., to provide protection

[569] Alberta Energy and Utilities Board. 1994. *Directive 051: Injection Disposal Wells*, p. 4, http://www.eub.ca/docs/documents/directives/Directive051.pdf

[570] Alberta Energy and Utilities Board. 2003. *Interim Directive ID 2003-01 1) Isolation Packer Testing, Reporting, and Repair Requirements; 2) Surface Casing Vent Flow/Gas Migration Testing, Reporting, and Repair Requirements; 3) Casing Failure Reporting and Repair Requirements*, http://www.eub.ca/portal/server.pt/gateway/PTARGS_0_212_164245_0_0_18/

	against caving of weak formations).
Isotope	An isotope is a form of a chemical element whose atomic nucleus contains a specific number of neutrons, in addition to the number of protons that uniquely defines the element.[571]
Logging	Logging describes measurements taken in the wellbore to gather information on the rocks, including the presence of hydrocarbons. A variety of techniques can be used and the tools are typically lowered into the wellbore on a wire.
Microbes	Microbes are microorganisms, such as bacteria, viruses, fungi and protozoa, that are too small to be seen with the naked eye.
Overbalanced drilling	In overbalanced drilling, the pressure in the formation is less than that in the well casing.
Permeability	A permeable rock or formation is one that allows water or other fluids to gradually pass through it.
Pool	The *Oil and Gas Conservation Act*, section 1(1)(oo), states that "pool" means "a natural underground reservoir containing or appearing to contain an accumulation of oil or gas, or both, separated or appearing to be separated from any other such accumulation."[572]
Porosity	Porosity refers to the open spaces within a rock that contain fluids such as water, oil or natural gas.
Potable (water)	Potable water is water that is safe to drink. It may be defined as water with less than 500 mg/l total dissolved solids (although well water used for consumption may sometimes have higher levels).
Produced water	This is water that flows to the surface with the production of gas or oil.
Production casing	According to the EUB production casing is "The last casing string set within a wellbore, which contains the primary completion components. No subsequent drilling operations are conducted after setting production casing; otherwise the string must be designed as productive intermediate

[571] *Whatis.com.* 2002, http://whatis.techtarget.com/definition/0,,sid9_gci860646,00.html

[572] Under Section 33(1)(b) of the *Oil and Gas Conservation Act*, the EUB may designate a pool by describing the surface area vertically above the pool and by naming the geological formation in which the pool occurs or by some other method of identification that the EUB considers suitable. This is explained in more detail in Alberta Energy and Utilities Board. 2006. *Bulletin 2006-16: Commingling of Production from Two or More Pools in the Wellbore,* Appendix 7, Criteria for Designating CBM Pools, Background, p. 30, http://www.eub.ca/docs/documents/bulletins/Bulletin-2006-16.pdf

[573] Alberta Energy and Utilities Board, 1990. *Directive 010: Guide to Minimum Surface Casing Design Requirements,* Appendix B Definitions, http://www.eub.ca/docs/documents/directives/directive010.pdf .

	casing."[573]
Saline water	Water that has total dissolved solids exceeding 4,000 mg/l is defined as saline water in the *Water (Ministerial) Regional*.[574]
Slickwater frac	This is a fracture treatment, used only in the U.S., that requires a large volume of water to create fractures in low permeability reservoirs.
Sodium adsorption ratio (SAR)	The Sodium Absorption Ratio (SAR) describes the amount of excess sodium in the soil in relationship to calcium and magnesium.[575] Excess sodium in relation to calcium and magnesium concentrations in soil (high SAR) destroys soil structure, resulting in hardpan layers that reduce the permeability of the soil to air and water.[576]
Stimulation of a well	This refers to any process, such as fracturing, that makes it easier for gas or oil to flow to the wellbore.
Stable isotopes	Stable isotopes are chemical isotopes that are not radioactive. Stable isotopes of the same element (e.g., carbon, hydrogen) have the same chemical characteristics and therefore behave almost identically.
Surface casing	The surface casing is the first string of casing put into a well. It is cemented into place throughout its length and forms the foundation for the well, and protects the well while deeper formations are drilled. It also helps to protect shallow groundwater.
Surface casing vent flow	This is a flow of gas or liquid up the annulus between the surface and production casing, which exits through the surface casing vent. The vent must be maintained in the open position so that vent material comes to surface, rather than going into a porous or permeable zone. Surface casing vent flows occur when there is a low cement top on the production casing or channels in the cement. If the surface casing vent flow has the potential to impact groundwater it must be fixed immediately.
Surface rights group	A surface rights group is a group of landowners who work to improve all aspects of the energy industry as it affects them. This may include educating its members on issues, lobbying the government and taking part in multi-stakeholder processes. A surface rights group does not

[574] This is the definition in Alberta, as given in the *Water (Ministerial) Regulation, section 1(1)(z).*

[575] Agriculture and Agri-Food Canada.1999. *Water Quality Fact Sheet: Irrigation and Salinity*, *http://www.agr.gc.ca/pfra/water/irrsalin_e.htm*

[576] Special Areas Board, Hanna. 2005. *Special Areas Water Supply Project*, p. 6, *http://www.specialareas.ab.ca/ProjectSummaryMay20am.pdf*

	include any representatives from industry or government.
Synergy group	A synergy group is a collaboration between stakeholders (often including landowner representatives, as well as those from industry and government) where the results are greater than what one stakeholder group could achieve on its own.
Tiltmeter	A tiltmeter is an instrument used to measure small changes in the slope or tilt of the Earth's surface. It works much like a spirit level, with a liquid bubble inside a chamber that responds to changes in tilt.
Total dissolved solids (TDS)	Total dissolved solids are a measure of the concentration of dissolved matter (primarily mineral salts) found in a liquid such as water. Usually expressed as the weight per unit volume of filtered water.
Unconventional gas	Unconventional gas is gas that requires special drilling, completion, and/or stimulation (such as fracturing of the formation) technologies to develop and maintain the flow in commercial quantities.[577]
Underbalanced drilling	This occurs where the hydrostatic pressure within the casing (or drilling column) is lower than that in the formation.
Usable water	The EUB sometimes uses the term to describe groundwater with total dissolved solids of 4,000 milligrams per litre or less.[578]
Underground source of drinking water (USDW)	This is a term used in the U.S. for certain areas where the water is given some degree of protection.
Zone	In many cases a zone refers to a geological stratum or series of strata, but it is sometimes used to describe a larger geological group that includes more than one formation.

[577] For a more detailed description of unconventional gas, see Petroleum Technology Alliance Canada. 2006. *Filling the Gap: Unconventional Gas Technology Roadmap*, p. 8, http://www.ptac.org/cbm/dl/PTAC.UGTR.pdf

[578] Alberta Energy and Utilities Board. 2005. *Directive 056: Energy Development Application and Schedules (September 2005)*, Section 7.9.9, p. 176, http://www.eub.ca/docs/documents/directives/directive056.pdf

Appendix C: Abbreviations

bcf	billion cubic feet
BGWP	base of groundwater protection
BTEX	benzene, toluene, ethylbenzene and xylene
CBM	coalbed methane
EPA	Environmental Protection Agency; the U.S. department that regulates federal environmental issues.
EUB	Alberta Energy and Utilities Board.
MAC	Coalbed methane/Natural Gas in Coal Multi-Stakeholder Advisory Committee
m^3	cubic metre
mcf/d	thousand cubic feet per day. In some documents mcf/d is used as an abbreviation for million cubic feet per day.
mg/l	milligrams per litre
MSDS	Material Safety Data Sheet
NGC	natural gas in coal
PTAC	Petroleum Technology Alliance Canada
SAR	sodium adsorption ratio
tcf	trillion cubic feet
TDS	total dissolved solids
THM	trihalomethanes
USDW	underground source of drinking water (in U.S.)