**Title:** CBM Produced Water – The Emerging Canadian Regulatory Framework

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# PREFACE

The energy sector has been a dominant factor in Alberta's development and growth over the last half-century. The large capital investments and operating expenditures associated with finding and producing oil and gas have directly provided a major stimulus to the economy. But the indirect and induced impacts have been equally important. The development of many other industries supplying inputs to the energy sector, the generation of substantial export and government revenues, and the stimulus for large inflows of people have resulted in large 'multiplier' effects. In combination, these have also played a major role in shaping Alberta's 'character' which is generally distinguished by its highly educated, adjustable and entrepreneurial labour force, low unemployment and high labour force participation rates, strong work ethic and sense of self reliance, and its optimistic outlook.

In recent years the energy sector has become even more dominant and has increasingly made Alberta a key driver of the national economy. In a world with a rapidly growing demand for energy, having one of the largest concentrations of energy resources in the world might seem to translate into an assured, prosperous future. There is clearly huge potential associated with unconventional oil and gas, coal, remaining conventional resources and with alternative and renewable energy. However, translating this potential into reality will be daunting. Increasing constraints related to resource access, environmental impacts, infrastructure requirements, and availability of highly qualified people need to be addressed. Other challenges include the massive long-term investments in developing and implementing new technologies and making the right changes in the policy and regulatory framework. Indeed, the fact that relatively few nations have managed to convert resource wealth into high standards of societal welfare is a useful reminder of the magnitude of the challenges.

Alberta is in many respects at a crossroads. On the one hand complacency will almost certainly mean a dimming of the province's long-term prosperity. Declines in the conventional oil and gas sector will significantly dampen growth and prosperity. There are no other sectors of the province's economic base that could realistically expand sufficiently to offset significant declines in the dominant energy sector. On the other hand, visionary, strategic investments today can unlock non-conventional and other energy resources critical to securing a strong and prosperous long-term, sustainable future for the province.

It is in this context that ISEEE has undertaken a series of papers focused on Alberta's energy futures. The intent is to take a longer term look at the challenges, opportunities and choices and what they mean for Alberta's future. This first paper provides both a retrospective and a prospective overview of the impacts of the oil and gas sector. It is intended to frame and highlight the longer term issues and provide an anchor for more detailed analysis in subsequent papers.

# CBM Produced Water - the Emerging Canadian Regulatory Framework

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**DRAFT**

## INTRODUCTION

It is anticipated that at least 4,200 coalbed methane (CBM) wells will be drilled in Alberta this year[1]. In light of the anticipated increase in commercial production from wet coals within ten years and the controversy surrounding the impact of CBM development on provincial water resources, this paper will review the current and emerging provincial regulatory framework that governs CBM produced water and the associated environmental impacts.[2] The emerging provincial regulatory system in western Canada will be analyzed in the context of the CBM development experience in the western United States, American best management industry practices and the Alberta Multi-Stakeholder Advisory Committee Recommendations released in May 2006.

CBM is natural gas that occurs in coal seams. In several western states, there has been commercial production of CBM for two decades, however Alberta is the only province with appreciable commercial production. Much of central and southern Alberta is

[1] Kevin Lo and Steven Paget, "Coalbed Methane Activity Update", The Negotiator, Canadian Association of Petroleum Landmen, May 2006; the number of wells may amount to 6000, see http://www.gov.ab.ca?can/200604/196877041CC67-B4C4A683_BC4A6C2815ACH.html.
[2] For a discussion of these impacts see Mary Griffiths and Chris Severson-Baker, "Unconventional Gas – The environmental challenges of coalbed methane development in Alberta, June 2003, Pembina Institute.

underlayed by coals with the potential for CBM development.[3] Encana has budgeted 4.5 billion and other companies a total of 9.1 billion to be spent on CBM exploration and production in the next five years.[4] In 2004, western Canadian CBM production constituted only 0.5% of the total provincial marketable gas production, however the Alberta Energy and Utilities Board (EUB) predicts that by 2014, 12% of that production will be attributed to CBM.[5] By the year 2025, it is anticipated that 80% of the new wells drilled in Alberta will target CBM and the energy resource will account for 50% of the total marketable natural gas production.[6]

To date, most of the Alberta CBM production has been from "dry coal," in the Horseshoe Canyon Formation, that contains little or no water.[7] However in 2005, some CBM wells in the same formation encountered water, and in addition commercial production was reported from wet coals in the Mannville Group which contain saline water.[8] These coals extend into British Columbia and Saskatchewan. Currently there is limited data on the volume of water that may be produced from wet coals in western Canada. Recent media reports in Alberta have focused on the environmental problems attributed to the surface discharge of produced water in the western United States, and potential problems reported

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[3] The Horseshoe Canyon formation is thought to contain 66 tcf of CBM, the Scollard Formation 53 tcf, Belly River Group 66 tcf and the Mannville Group 329 tcf potential resource-in place, See Jeffrey Fiell, "Opportunities in Coalbed Methane, Economic Upside for Investors," Octagon, January 30, 2006, pp. 14-15.
[4] "Another giant in the making CBM has done in a few years what took decades for oilsands booster" Financial Post, April 3, 2005, p. FP5.
[5] http://www.eub.gov.ab.ca.
[6] Id.
[7] Id., 90%.
[8] Lynda Harrison, "Horseshoe Canyon Can Be Wet; Corbett Could Be A Giant", Nickle's Daily Oil Bulletin, November 14, 2005; Lynda Harrison, "Mannville CBM Project Goes Commercial", Nickel's Daily Oil Bulletin, July 14, 2005.

to occur in the U.S. due to methane migration into landowner water wells.[9] For several years provincial regulators in Alberta and British Columbia have monitored the CBM development experience in the western U.S.A. and the potential environmental and social impacts from development.

**PRODUCED WATER IMPACTS IN THE WESTERN UNITED STATES**

As CBM remains absorbed or attached to the coal due to overlying pressure from rock and/or water, the pressure in the coal seam must be reduced to facilitate methane production. This is accomplished by removing the overlying water through a dewatering stage that allows the CBM to separate from the coal and be pumped to the surface. Water pumped during this stage and subsequent production stages is referred to as produced water. Regulators in the United States have had more experience in managing large scale CBM development than in any other country.[10] CBM development in the western U.S.A has revealed the quantity and quality of water produced from CBM wells will vary from basin to basin and at individual sites within each basin.[11] "Wet" coals, such as those found in the San Juan and Powder River sedimentary basins[12] have produced significant volumes

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[9] Western Organization of Resource Councils, "Coalbed Methane Development, Boon or Bane for Rural Residents", Fact Sheet, March 2003, Laura Severs, "Unconventional gas plans raising fears," Business Edge, March 16, 2006, Vol. 6, No. 6; Renata D'Aliesio, "U.S. Rancher warns of coal bed methane's poison," Calgary Herald, March 10, 2006, B3; Andrew Nikiforuk, "Coalbed worries addressed slowly," Calgary Herald, March 10, 2006, Hanneke Brooymans, "Taps of fire near drill site spook resident," Calgary Herald, December 13, 2005.

[10] The environmental impact assessment for the most extensive drilling and development program in the world was approved in 2003. Please refer to BUREAU OF LAND MANAGEMENT, FINAL STATEWIDE OIL AND GAS ENVIRONMENTAL IMPACT STATEMENT AND PROPOSED AMENDMENT OF THE POWDER RIVER AND BILLINGS RESOURCE MANAGEMENT PLANS, Vol. 1, January 2003.

[11] Gary Bryner, Coalbed Methane Development In the Intermontane West: A Primer, University of Colorado School of Law (2002).

[12] See D.O. Cox et al, "Water Disposal From Coalbed Methane Wells in the San Juan Basin", 68th Annual technical Conference of the Society of Petroleum Engineers, Houston Texas, October 3-6, 1993, SPE 25970, J.P. Kaszuba et al, "Reclamation Procedures for Produced water Spills from Coalbed Methane Wells San Juan Basin, Colorado and in New Mexico, SPE/EPA Exploration & Production Environmental Conference,

of fresh and saline water. At some CBM well sites in Wyoming, the produced water is of drinking water quality, but at other sites it is saline or contains natural salts and other elements that may prompt treatment prior to discharge.[13] Produced water may contain drill bit cuttings, lubricants, oil and diesel, that if improperly managed can pollute surrounding creeks and rivers when discharged on to the surrounding landscape. In addition to the impacts from the discharge of produced water, other issues including methane migration[14] and the impact of CBM production on aquifers raise important questions.[15] In light of the U.S. experience, these issues need to be addressed in the emerging provincial regulatory regimes.

**PRODUCED WATER MANAGEMENT OPTIONS**

As the natural chemical content[16] of produced water can be different in each well, the potential environmental impacts can vary at each site. A regulatory framework that provides for mitigating environmental impacts from development must account for individual site characteristics. Pumping water from CBM wells to facilitate methane production has also raised questions about the impact of groundwater removal on aquifers and the potential depletion of sources of potable water for future domestic consumption and

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San Antonio, Texas, March 7-10, 1993, SPE 25970, Gary Bryner, Coalbed Methane Development In The Intermontane West, A Primer, University of Colorado School of Law (2002).

[13] Supra, note 11.

[14] Methane migration is the process under which methane can move from a CBM well into the soil or water wells; Please see Vito Nuccio, COAL-BED METHANE: POTENTIAL AND COCNERNS, United States Geological Survey, FS-123-00 (2000).

[15] Gary Bryner, Coalbed Methane Development In The Intermontane West: A Primer, University of Colorado School of Law at p. 13-2 (2002).

[16] Major ions such as Na, Ca, Mg, bicarbonate, sulfate and chloride.

use.[17] In regard to CBM production from "wet" coals, the expense of water management and disposal has been calculated to be a significant factor in the economic viability of CBM projects.[18] Produced water disposal is managed through surface discharge, subsurface injection or beneficial use of the water. The type of water disposal approved by state regulators requires analysis of the water to determine the chemical content. [19] If the produced water is mineralized, the water may require treatment before disposal. Regulators in Wyoming and Montana have adopted different standards to evaluate the mineral content and quality of the water.[20] Surface discharge of produced water releases the water along the land surface into creeks or rivers, or if saline into structures such as tailing ponds, or excavated pits for treatment. The U.S. Department of Energy has reported the "lowest cost option that results in the largest estimates of economically recoverable gas," is allowing the water to flow along the ground surface into creeks and rivers. Regulators in Alberta and British Columbia are aware of the concerns of some landowners and environmental groups in Wyoming, Montana, Colorado, New Mexico and Utah about the environmental impacts arising from the surface discharge of water such as increased erosion, commingling of water of different qualities, and the destruction of wildlife habitats and ecosystems.[21] In 2004, the Governor of Montana objected to CBM development near Fernie, B.C., due to

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[17] C.A. RICE *et al*, WATER CO-PRODUCED WITH COALBED METHANE IN THE POWDER RIVER BASIN, WYOMING: PRELIMINARY COMPOSITIONAL DATA. http://www.wy.blm.gov/mineral/og/cbmdocs/usgs_ofr/openfileerptoo_372.pdf (2000).

[18] W. THOMAS GOEROLD, REVISED POWDER RIVER BASIN COALBED METHANE FINANCIAL MODEL (MAY 15, 2002).

[19] The EPA relies on the Clean Water Act and the Safe Drinking Water Act, to monitor the quality of water. If the water is determined to be saline, depending upon the mineral content of the produced water (total dissolved solids), some state regulators will require treatment of the water before surface discharge. At some sites the mineral content of the water will preclude treatment and subsurface injection will be required.

[20] Wyoming regulators apply narrative standards to evaluate water quality however in Montana numeric standards are used.

[21] Andrew Nikiforuk, "Coalbed Worries Addressed Slowly", Calgary Herald, March 10, 2006; Disposal of Water Produced During Coalbed Gas Extraction (BC govt page).

concerns about the downstream impact of produced water on the Flathead River that flows into the state.[22] There are regulations in several states that restrict or prohibit the surface discharge of saline water. Due to the regulatory requirements or in some cases the significant expense of storing and treating saline produced water before surface discharge[23], the second method of water disposal frequently employed is subsurface injection. Produced water is injected into subsurface disposal wells that are insulated from groundwater, to prevent the contamination of potential sources of drinking water. A third water management method employed in the western United States is the beneficial use of produced water, such as diverting the water into storage for watering livestock or irrigation.

## THE WESTERN GOVERNORS' ASSOCIATION BEST MANAGEMENT PRACTICES

In response to lawsuits and controversies arising from CBM development in the western states, the Governors of Wyoming, Montana, Colorado, New Mexico and Utah, sponsored an initiative to encourage the development of best management practices (BMPs) in the CBM industry.[24] After extensive consultation amongst stakeholders including landowners, environmental groups, industry and government, the project culminated with the identification of BMPs in April 2004. A BMP is defined in the western U.S.A. as a "proven way of conducting CBM operations that eliminates or minimizes adverse impacts from CBM development on public health, the environment, landowners and natural

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[22] Scott Simpson, "Gas Drilling plan speaks fight", Vancouver Sun, July 24, 2004, at http://www.dogwoodinitiative.org/news_stories/archives/000559.html, Mark Lowey, "CBM proposal fuels cross-border battle", Business Edge, Vol. 4, No. 29, August 1, 2004.

[23] For a discussion of the technology available to treat the water see Florence Hum et al, "Review of Produced Water Recycle and Beneficial Reuse, March 2005.

[24] Western Governors' Association, Coal Bed Methane Best Management Practices – A Handbook, April 2004, from www.westgov.org.

resources; enhances the value of natural and landowner resources and reduces conflict."[25] BMPs are voluntary industry practices endorsed by the Western Governors that do not replace the regulatory requirements. The Canadian Association of Petroleum Producers[26] is in the process of developing a set of best management practices for the emerging Canadian CBM industry.

American BMPs relevant to produced water, focus on water management planning, protecting water quality, and the beneficial use of produced water. Members of the Coal Bed Methane Advisory Committee for the Western Governors' Association included regulators from the U.S. Environmental Protection Agency, the Bureau of Land Management, United States Department of Agriculture, the U.S. Forest Service, individual states, oil companies, environmental groups and other stakeholders.[27] Three BMPs focus on water management planning. The first provides for the preparation of a water management plan by the CBM developer[28]. As part of the plan developers are to consult with surface owner(s) and other affected water-users early in the planning process and throughout the development of the plan. The second water management planning BMP prompts developers to consider the following twelve factors before drilling CBM wells:

- Landowner preference and concerns
- Quantity and quality of water to be discharged
- Quality of the receiving water standards

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[25] Id., p. 4.
[26] "A industry organization that represents 140 companies that explore for, develop and produce more than 97% of Canada's natural gas and crude oil, "Towards responsible coalbed methane development in Canada", (March 2003).
[27] Id., Appendix C.
[28] Id, p. 7.

- Environmental/ecological impacts from surface discharge
- Downstream concerns
- Economic feasibility/cost effectiveness
- Beneficial use possibilities
- Proximity to streams/ponds/reservoirs/wetlands/lakes
- Proximity to clinker/scoria and gravel deposits
- Proximity to springs
- Long-term impacts to the environment
- Protection of groundwater, and evaluate different options for the management of produced water."[29]

The third BMP provides that a CBM developer "will ensure that the capacity of the receiving aquifer is adequate to handle the anticipated volume of water to be injected."[30]

The following four BMPs have been adopted in the western U.S.A. to protect and maintain the quality of water resources:

- "establish baseline data for ground and surface-water quality in the area where development will occur;
- provide landowners who want well monitoring data with the data or direct them to the appropriate data source such as a regulatory agency;

[29] Id., p. 8.
[30] Id, p. 9.

- develop an understanding of the basin hydrology before selecting drill sites to ensure that CBM wells are at an adequate distance from water wells to prevent methane seepage and water well contamination;
- discontinue the use of diesel fuel in hydraulic fracturing fluids injected directly into formations that contain underground sources of drinking water."[31]

Our review of the current regulatory framework in Alberta and British Columbia indicates that all of the above BMPs which are voluntary practices in the western U.S.A. have been adopted as regulatory requirements in western Canada. For example, the injection of diesel fuel into formations that contain drinking water is prohibited in Alberta, under the *Environmental Protection and Enhancement Act*[32].

Beneficial use of produced water is not yet addressed on a comprehensive basis in the Alberta regulatory framework. The U.S. BMP provides that **"**when a landowner is interested in using produced water, the developer should provide information about options for beneficial use and about potential problems and liability."[33] One potential problem observed in semi-arid areas of the western U.S.A., arises from creating dependency on a new source of water. After farmers and ranchers have become reliant on produced water, at the end of the productive life of the well and the availability of produced water, they can no longer sustain their operations.

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[31] Id., pp. 8-10.
[32] RSA. 2000, c.E-12.
[33] Supra, note 24, pp. 9 -10.

To date the only governments in Canada that have considered CBM development in some detail, are the Alberta and B.C. governments. In the next section we will review the existing provincial regulatory frameworks to evaluate the extent to which they incorporate the U.S. BMPs.

## REGULATION OF PRODUCED WATER IN ALBERTA

Before developing their respective regulatory frameworks, the Alberta and B.C. governments sent delegations to the western U.SA. to investigate reported problems attributed CBM development. Provincial regulators met with their American counterparts to discuss these problems. In addition a representative from the Alberta Department of Energy served on the advisory committee to develop the BMPs. As the Alberta Government considers CBM to be another form of natural gas, it has modified legislation and regulations developed for conventional natural gas wells to regulate CBM operations. Information Letter 91-11[34], indicates all statutes and regulations that apply to conventional natural gas wells will apply to CBM wells. The Alberta Energy Utilities Board (EUB) and the Department of Alberta Environmental Protection (AENV) are the two main agencies that regulate water produced from CBM wells. The EUB, as the main regulator of energy projects, relies on the *Oil & Gas Conservation Act*, and *Energy Resources Conservation Act*,[35] to monitor oil and gas well drilling. Pursuant to the *Environmental Protection and Enhancement Act* (EPEA) and the *Water Act (WA)*[36], the mandate of AENV is to ensure provincial water resources are protected and sustained for current and future generations.

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[34] EUB <http://www.eub.gov.ab.ca/BBS/requirements/ils/ils/il91-11.htm>.

[35] R.S.A. 2000, c.  R.S.A. 2000, c. 0-6.
[36] R.S.A. 2000, c. E-12 and R.S.A. 2000, c. W-3, respectively.

Authorizations from the EUB and AENV may be required for individual CBM wells. As ownership of all water lies with the Crown in AB, licences are required to use, dispose and divert all water in the province. If there is the potential for a CBM well to produce non-saline water, a licence is required under the *WA.* AENV focuses on the regulation of produced non-saline water. Water that contains more then 4,000 milligrams per litre of total dissolved solids (mg/L TDS) is considered to be saline.[37] In light of its experience in regulating saline water from conventional wells, the EUB has the primary responsibility to regulate subsurface injection of saline water.

**NON-SALINE WATER**

The production, diversion, and disposal of non-saline surface and groundwater are regulated under the WA and EPEA by AENV. CBM developers must follow the application procedures specified in the "Guidelines for Groundwater Diversion for CBM/NGC Development adopted in 2004."[38] The diversion of water is defined broadly in s.1(1)(m) of the *WA* to include "…the impoundment, storage, consumption, taking or removal of water for any purpose…" or "…any other thing defined as a diversion in the regulations…".[39] To obtain approval for a proposed activity, evidence must be provided by the applicant to substantiate the diversion will not damage a source aquifer or other aquifers and will not have an immediate or long-term impact on nearby water supplies. CBM developers must apply for a permit if it is anticipated that non-saline water will be encountered in a proposed well. The developer must complete and submit a preliminary

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[37] "Alberta Environment Guidelines for Groundwater Diversion." Alberta Environment (2004). pg.2.
[38] <http://www.3gov.ab.ca/env/water/Legislation/Guidelines/groundwaterdiversionguidelines-methgasnatgasincoal.pdf>.
[39] *Supra* at 21.

groundwater assessment (PGA) to AENV. The purpose of the PGA is to collect local baseline data and identify issues of interest to regulators and the public. As of May 1, 2006, the EUB requires all CBM developers to offer to conduct baseline well testing before a new well licence application to drill or re-complete CBM wells above the base for groundwater protection can be issued. [40] The new well testing program is designed to ensure that the water quality is determined and a baseline established before drilling proceeds. Landowners are encouraged to agree to testing water their wells when contacted by a CBM developer. If the landowner agrees to baseline testing, a program will be carried out on all active water wells within a minimum 600 metre radius of the proposed drilling or re-completion involving fresh water (with perforations above the base of groundwater protection). If there are no wells within 600 metres, the company must offer to provide testing for at least one well up to 800 metres. Baseline information on the productive capability of the water well, water quality, including bacteria, and the presence or absence of gas, including methane will be collected. CBM developers must pay for the well water testing and provide the landowner and AENV with the results. Mandatory testing of water wells before CBM drilling proceeds is consistent with the *Water For Life* strategy adopted by the Alberta government. Increased baseline data will improve regulator knowledge of provincial water resources and should assist in protecting the quality of water wells. The sample results are to be filed with AENV as part of the new water well testing information database. The database will be used to evaluate the baseline testing initiative after six months and again at twelve months to produce a public report. The results of the baseline

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[40] Alberta Government Backgrounder, April 6, 2006, at http://www.gov.ca/acn/200604/19687741CC67-B632-6A83-B4FC4A6C2815ACFO.html; See EUB Directive 035, Baseline Water Well Testing Requirement for Coalbed Methane Wells Completed Above the Base of groundwater Protection, May 8, 2006.

testing results should also provide information to assist with an investigation when there are complaints about water contamination from CBM exploration or production activities. Baseline data is collected to help identify any groundwater changes that may occur from CBM development over time. The PGA must contain extensive technical data including the proposed locations of test holes and exploratory wells, surface water bodies and field-verified surveys of water wells, springs, and dugouts, surface water bodies, drainage courses, roads and infrastructure. Potential users and receptors of produced water must be reported along with the concerns of well/property owners about the proposed CBM project. As part of the PGA, a technical report must be prepared that covers all aspects of the water diversion\disposal program and how it will affect the environment and stakeholders. The report should include a description of the geologic and hydro-geological conditions in the project area[41] verified by a field survey, a description of the drilling program including test hole and observation well locations, drilling methods, aquifer parameters, water sample test results, gas sample test results, selected aquifer water quality sample results, an operational water management plan, consideration of cumulative impacts, a description of the water monitoring program and a mitigation program to address environmental impacts.

**PUBLIC NOTIFICATION**

Once an application has been submitted to AENV, the CBM operator must notify the public about the project concerning the proposed diversion or disposal of produced water. This provides the public with some awareness of the proposed diversion/disposal program and the opportunity to raise concerns or submit questions. If any concerns or questions are

[41] Including historical water well records if available at www.gov.ab.ca/env/water/groundwater.

received, the CBM operator is required to respond in writing to those parties directly affected by the proposed diversion/disposal program. Copies of all correspondence between the operator and affected parties must be filed with AENV.[42]

If an application is approved, the CBM operator can commence the de-watering phase for the project. All produced water must be diverted or disposed of in the manner approved by AENV. Authorization is usually granted with conditions which may include requirements for monitoring production volumes, performing on-going water quality analyses, and monitoring water levels over time. The regulator may also require the operator to drill dedicated observation wells into the targeted coal zone to monitor the effects of groundwater production.[43] Flexibility in the requirements for CBM development exist within the regulatory framework through exemptions from certain requirements.

**SURFACE DISCHARGE**

The CBM operator must apply to the EUB and AENV for permission to dispose of non-saline water onto the ground surface or into a suitable shallow subsurface aquifer. Historically, the disposal of produced water above the base of groundwater protection ("BGWP") or on the surface has not been allowed in Alberta. However, if the information collected and presented to the EUB and AENV from the Preliminary Groundwater Assessment indicates that the environment or subsurface aquifers will not be damaged, these disposal methods will be considered. Currently there are no guidelines for the approval of surface or shallow aquifer disposal. The EUB and AENV currently consider

[42] Id. at 3.
[43] Id.

these disposal methods on a case-by-case basis in light of the "Surface Water Quality Guidelines for Use in Alberta".[44]

Saline water diversion[45] technically falls under the *WA*[46] but is exempt from AENV jurisdiction under the *Water (Ministerial) Regulation*,[47] as the EUB has been assigned the responsibility to regulate saline water. In respect to co-mingling groundwater of different salinities, the standards developed by AENV are applied by the EUB, and CBM operators must follow EUB requirements. The EUB requires all saline water to be returned to the zone of origin if below the BGWP, or if not below the BGWP, to a zone deeper than the BGWP. *EUB Directive 065: Resources Application for Conventional Oil and Gas Reservoirs*[48] and *EUB Guide 51: Injection and Disposal Wells* [49] must be followed.

The CBM operator must track, monitor, and report information on the disposal of produced water to the EUB. The regulatory monitoring requirements are outlined in Part 12 of the *Oil and Gas Conservation Regulation*[50], *EUB Guide 7: Production Accounting Handbook*[51] and *EUB Guide 59: Well Drilling and Completion Data Filing Requirements*.[52]

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[44] Available at http://www3.gov.ab.ca/env/protenf/publications/surfwtrqual-nov99.pdf.
[45] Saline water is defined as TDS more than 4000mg/L in s.1(1)(z) of the *(Water Ministerial) Regulation*, Alta. Reg. 205/98.
[46] R.S.A. 2000, c. W-3.
[47] Alta. Reg. 205/98, s.1(e) of Schedule 2.
[48] Available at http://www.eub.gov.ab.ca/bbs/documents/directives/Directive065.pdf.
[49] Available at http://www.eub.gov.ab.ca/bbs/products/guides/g51.pdf.
[50] AB Reg. 151/71.
[51] Available at http://www.eub.gov.ab.ca/bbs/products/guides/g07/g07-2001.pdf.
[52] Available at http://www.eub.gov.ab.ca/bbs/products/guides/g59.pdf.

This review of the Alberta regulatory framework indicates that the U.S. best management practices for water management planning and water quality have been incorporated into the Alberta regime as regulatory requirements. A water management plan must be prepared, and the twelve factors outlined in the U.S. BMPs must be considered before drilling is approved. In respect to BMPs providing for baseline data, well testing is strongly encouraged in Alberta before drilling is approved. In regard to BMPs designed to protect and maintain water quality, the Alberta regime requires monitoring CBM development impacts on water resources. The Alberta regime prompts developers to understand basin hydrology before CBM projects can be approved. In respect to the fourth BMP that provides for discontinuing the use of diesel fuel in fracturing fluids, EPEA prohibits the injection of deleterious substances such as diesel fuel into the environment. In respect to subsurface injection of produced water, the provincial regulatory approval framework prompts some "understanding of the capacity of the receiving aquifer to handle the anticipated volume of water to be injected."[53] Provincial regulators must consult with landowners, surface occupants and other stakeholders concerning proposed projects prior to approval of a CBM project.

## REGULATION OF PRODUCED WATER IN BRITISH COLUMBIA

There has been no significant commercial CBM production in B.C. yet, however the provincial government is aware the Mannville coal zone that contains substantial CBM reserves is wet.[54] CBM test wells drilled to date indicate that produced water may be non-

[53] Surpa, note 24, p. 9.
[54] TDS concentrations in this zone are approximately 40, 000mg/L; Deborah Jaremko, " Producers try to crack the Mannville NGC , Oilweek, Aug. 2005 – Unconventional Gas Special Supplement 'Risky Business'.

saline or saline,[55] however as most of the wet coal projects are experimental, available data is limited.[56] As in Alberta, produced water is regulated by multiple regulatory bodies. The B.C. Oil & Gas Commission is the main regulator for CBM operations and has analogous functions to the EUB. The Ministry of Water, Land and Air Protection, like AENV, administers permits for water production under the *Environmental Management Act* (EMA)[57]. While the regulatory authorities are similar, the B.C. Government unlike the Alberta Government has created legislation and a CBM Code of Practice that is specific to CBM. In B.C. the disposal of produced water is regulated by the Ministry of Environment ("ME") and the Oil and Gas Commission ("OGC"). The ME oversees the application of the EMA as it is the provincial agency responsible for environmental protection. The OGC regulates the drilling of oil, gas and CBM wells. Although the ME and OGC both regulate produced water, the OGC is the main regulator that administers the application review and approval process. The OGC employs a three-phase approach for CBM development that includes evaluation, feasibility, and production. Each phase requires an application to the OGC that outlines the plans for each phase for the following purposes:

1) Evaluation Phase– to determine the technical feasibility of a proposed CBM project through test drilling and the collection of produced water;
2) Feasibility Phase – to ascertain the commercial viability of a project through the operation of 20 to 40 wells; and
3) Production Phase – the establishment of a full-scale commercial recovery of CBM reserves.

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[55] Coalbed Gas: Energy for our Future.
[56] Tristone Capital, (Aug. 5, 2004).
[57] S.B.C. 2003, c.53.

A *Code of Practice for the Discharge of Produced Water from Coalbed Gas Operations* ("COP")[58] has been created that came into effect on July 1, 2005[59]. The COP is designed to ensure that when water is produced[60], the surrounding environment including surface and groundwater are protected from contamination. During the dewatering phase, companies must determine both the water quality and quantity prior to commercial production, because these are factors that weigh heavily in the determination of how to appropriately dispose of or use the produced water. If a company proposes to discharge the produced water it must complete baseline monitoring similar to the Preliminary Groundwater Assessments required by AENV. Surface discharge is to be restricted to perennial streams, seasonal streams, or "by percolation through the ground."[61] The COP contemplates several disposal options including beneficial use of produced water. Even though re-injecting water into the formation from which it originated is the most commonly used method, other alternatives, such as surface discharge, treating the water (to meet the standards set by the Ministry of Water, Land and Air Protection) and then disposing of it , and beneficial use of non-saline water for irrigation, habitat, livestock or recreation purposes, are possible.

The first step in the application process requires a preliminary water analysis test and the development of a receiving environment baseline monitoring program, designed and

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[58] Available at: http://wlapwww.gov.bc.ca/epd/coalbed_code/pdfs/coalbed_reg.pdf.
[59] Hereinafter referred to as the "Code".
<http://www.env.gov.bc.ca/epd/coalbed_code/pdfs/coalbed_reg.pdf>.
[60] The Coalbed Gas Act, s.1 "produced water" means water extracted from a coal seam or a formation contiguous to a coal seam that :
(a) originates from within the coal seam or contiguous formations,
(b) is pumped out in advance of and in aid of the release of gas from the coal seam, and
(c) is produced in the course of a coalbed gas exploration and production industry operation.

[61] Code of Practice for the Discharge of Produced Water from Coalbed Gas Operations (COP), s.2.

conducted by a qualified and licensed professional.[62] Results of the preliminary water analysis test must satisfy the numerical standards set out in the COP, for the following parameters: Total Dissolved Solids, Total Suspended Solids, Chloride (Dissolved), Temperature, Dissolved Oxygen, Boron content (seasonal only), Toxicity to Fish, and Toxicity to Invertebrates.[63] The standards vary depending on whether the discharge is into a perennial or seasonal stream. In respect to surface discharge, the COP requires a ground disposal facility to be used, the total dissolved solids in the produced water be less than or equal to two times the underlying ground water values, and the total suspended solids be less than or equal to 25mg/L.[64]

A baseline environmental monitoring program must be conducted at least once a year before the initial discharge. If the discharge is into a stream, the program must include a survey of the current water quality, the aquatic biota and riparian vegetation community, and the current flow of the stream. If the discharge is into the ground, the program must include a survey of the current quality of the groundwater.[65] A company proposing surface discharge under the COP must register and provide well information pursuant to section 4 of the *Waste Discharge Regulation* ("WDR")[66] for exemption from the WDR.[67] After the application for surface discharge to the OGC is complete and satisfies the COP, applicants must also submit information to the OGC for either a permit for discharge, or approval

[62] Id. at s.11.
[63] Id. at Schedules 1-3.
[64] Id. at s.6.
[65] Id. at s.11.
[66] B.C. Reg. 320/2004.
[67] Id. at s.8(3).

without the need for a permit under the EMA.[68] Additional approvals may be required under section 100 of the *Petroleum and Natural Gas Act*, [69] ("PNGA") including the approval to proceed with a scheme to gather, store, and dispose of produced water and section 94 of the *Drilling and Production Regulation*,[70] ("DPR"), which requires all produced water that will not be injected into a subsurface disposal well, must be approved by OGC. This does not necessarily imply that multiple separate applications need to be submitted, but rather an application satisfying all the regulatory requirements be forwarded to the OGC. Applicants for surface disposal authorization should also be aware of the OGC requirements in respect to public consultation outlined in the "Guideline for Approval to Dispose of Produced Water" ("GADPW")[71].

The COP addresses other issues such as the location of points of discharge relative to sensitive-stream habitat features, erosion effects, distance from existing drinking water and irrigation withdrawal points, the required flow rate of the streams,[72] the maximum amount of produced water that may discharged from a well ($1850m^3$/day),[73] and discharge proximity to drinking/irrigation water sources.[74] The COP outlines monitoring, record-keeping, and reporting of water discharge requirements to be completed on an ongoing basis. These include the development of programs to measure the quantity of water flow on a weekly basis and the development of ongoing environmental monitoring and

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[68] Environmental Management Act, S.B.C. 2003, c53, s.14 and 15.
[69] R.S.B.C. 1996, c.361.
[70] B.C. Reg. 362/98.
[71] Available at http://www.ogc.gov.bc.ca/arb/arb_print.asp?aoid=49 and is further discussed in Section C. Subsurface Injection.
[72] Id. at s.4(1)(a) in relation to perennial streams. s.5(1)(b) in relation to seasonal streams.
[73] Id. at s.8(1).
[74] Id. at s.13.

assessment reports for each year of discharge. Approved applicants are required to retain monitoring and assessment data gathered for periods ranging from a minimum of five years to the entire life of the project. [75]

CBM developers should be aware that a CBM project in B.C. might fall under the authority of the *Environmental Assessment Act*[76], either because of the length of time and rate at which water is to be produced from the ground, or because of significant pipeline construction. In both scenarios the CBM project could be classified as a reviewable project and the company would be required to obtain an environmental assessment certificate before proceeding with the development.[77] There are similar provisions in Alberta. For small projects involving multiple CBM wells as with conventional wells, a comprehensive and costly environmental assessment (EA) is not required under EPEA. However for CBM projects on a larger scale, an EA may be required, if the CBM development is of sufficient magnitude[78], or if the Minister of Environment is of the opinion that one is warranted.

Exemptions may be granted under the EMA for specific COP requirements.[79] A variance order under the EMA for specific relief on a temporary basis from permits or restrictions may be granted.[80] When the quality or volume of produced water does not satisfy the COP standards, companies must apply for an approval to inject the water into a subsurface formation. The targeted formation must be identified and the injection program structured

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[75] Id. at s.12 and 14.
[76] S.B.C. 2002, c.43.
[77] Environmental Assessment Act, S.B.C. 2002, c.43, s.5,6, and 8.
[78] EPEA.
[79] Environmental Management Act, S.B.C. 2003, s.138(2)(1).
[80] Id. at s.9.

to prevent any release of produced water into the environment. The regulatory authority for subsurface injection rests with the OGC under section 100 of the Petroleum and Natural Gas Act and section 94 of the DPR. The Guideline for Approval to Dispose of Produced Water (GADPW) developed by the OGC specifies the type of information required for an application for subsurface disposal.[81]

B.C. legislation, guidelines and COP incorporate the American BMPs. CBM developers in B.C. are required to evaluate how to manage produced water by considering factors such as the anticipated water quality and quantity, the cost of water treatment, the landscape of the receiving environment, the potential for beneficial uses such as irrigation, and existing infrastructure. In addition the B.C. regulatory framework more thoroughly addresses the issue of beneficial use of produced water than does the Alberta framework. It should be noted that the COP is intended to be a work in progress and changes are contemplated. The COP provides a well coordinated framework to protect water quality and address the potential impact of CBM development on aquifers. In light of the success of the COP in providing a more streamlined approval process than currently exists in Alberta, it is interesting to note that the Alberta CBM/NGC Multi-Stakeholder Advisory Committee has included in the recommendations released last week that the Alberta Government adopt a "decision tree approach" and a "code" [82] to improve the coordination of the regulatory approval process.

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[81] Available at http://www.ogc.gov.bc.ca/arb/arb_print.asp?aoid=49.
[82] The CBM/NGC Multi-Stakeholder Advisory Committee, "Coalbed Methane/Natural Gas in Coal Final Report", dated January 2006, at http://www.energy.gov.ab.ca/245.asp.

## CONCLUSION AND RECOMMENDATIONS

As the CBM industry is in its infancy in both Alberta and British Columbia, and each geological environment has unique characteristics, there is considerable uncertainty about the environmental impacts from CBM development on provincial water resources. The fact that the existing Alberta and British Columbia regulatory schemes incorporate American best management practices is encouraging, and suggests the provincial governments have created frameworks to address some of the problems reported in the western U.S.A. However in light of the importance of sustaining provincial water resources for future generations, the current framework can be improved by addressing the following unresolved water management issues:

1. The baseline data on provincial groundwater resources is currently inadequate;
2. It is unclear as to what the CBM development impacts will be on provincial aquifers, and what the scientifically based volume of produced water should be from a single CBM well or multiple wells in a specific area;
3. It is unclear as to what the level of drawdown should be from aquifers;
4. Standard procedures and reporting requirements for sampling, analysis and monitoring of produced water and water wells potentially affected by CBM development have not been incorporated into the regulatory framework;
5. It is unclear whether the current regulations governing drilling fluids, casing fracturing and completion practices developed for the conventional gas industry are adequate to prevent groundwater contamination;
6. It is unclear whether the current practice of using untreated river water or dugout water in CBM drilling fluids, negatively impacts aquifer water quality;

7. The current regulatory framework in Alberta does address the issue of beneficial use of non-saline produced water in detail;
8. There is uncertainty about the extent to which methane migration may be a potential problem in Alberta.

Please refer to the Multi-Stakeholder Advisory Committee (MAC) list of recommendations in the appendix at the end of this paper. The Alberta Government should act promptly on the MAC recommendations released last week. In respect the first issue, MAC has recommended AENV "complete its groundwater inventory in the province starting with areas that could experience intense CBM development", and the "EUB and the Alberta Geological Survey complete the Base of Groundwater Protection mapping project."[83] This information should be made available to the public in an easily accessible data base. To better protect aquifers and water supplies, MAC has recommended AENV determine a "scientifically-based threshold volume for produced non-saline water, below which a simplified approval under a Code of Practice for production or use of water would apply."[84] The volume determination and adoption of a Code should increase the consistency in the standards to be applied in Alberta and streamline the regulatory approval process. In respect to the third issue of aquifer drawdown, MAC has recommended AENV clarify the existing rules concerning aquifer drawdown.[85] The fourth issue pertains to the lack of standard procedures for water sampling, testing, monitoring and reporting. MAC's recommendation to develop quality assurance and control measures should be adopted by

[83] Id. at 7.
[84] Id.
[85] Id. at 8.

the government. In light of the fifth issue concerning the adequacy of regulations concerning drilling, fracturing and completion practices, MAC's recommendation for the EUB and AENV to review existing regulations in the context of the emerging CBM industry is prudent. In respect to the sixth issue, aquifer contamination from bacteria in untreated river water or dugout water used in drilling fluids, MAC's recommendation that research be undertaken to evaluate the environmental impact, provides increased protection for water resources.

As commercial production from wet coals in Alberta has been limited to date, the seventh issue beneficial use of produced water, is not one that regulators have focused on. The definition of what would be an appropriate beneficial use of produced water has yet to be determined in Alberta, however, suggestions include irrigation, impoundments (for example wildlife watering, recharge or evaporation ponds), industrial use or public and domestic use.[86] As ownership of water under the *Water Act*, is vested in the Crown, arguably produced water also belongs to the Crown. As wet coals have the potential to produce a significant volume of CBM, increased production from wet coals is probable. The Alberta government, in conjunction with the regulatory bodies responsible for oil and gas development should provide CBM developers with guidance as to whether produced water can be used, and if so under what conditions. With pending CBM projects in wet coals and the economic and environmental implications, the best policy and regulatory approach to the use of water is an important issue that needs to be addressed.

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[86] Feasibility Study for Coal Bed Methane Produced Water Management and Beneficial Use Alternatives. <http://www.pi.energy.gov/pdf/usrussaewg/hochheiser_cbm.pdf>.

Currently, the objectives listed in the *Water Act*[87] suggest that to give effect to the provisions within that Act, the Director must consider the purpose for which water is going to be used. The Director therefore, must consider whether or not a licence for a particular water use, disposal or diversion should be withheld because of the intended use. This issue tends to arise in the context of when a company applies to divert non-saline water, as in the Capstone case[88] for an industrial purpose. Requests from CBM producers for licences are distinguishable because those companies are applying to divert groundwater (usually saline) that is adsorbed to coal. The Director may only need to balance the interests of multiple users in these types of diversions if dewatering a CBM formation is going to cause adverse changes to the quality or quantity of groundwater in the vicinity of the well. It would appear that the EUB and AENV are both concerned about the mitigation of environmental impacts; therefore if companies comply with the existing regulations, then it would appear that companies are open to propose any and all ideas with respect to how they will beneficially use produced water. This raises a number of questions.

One issue is whether the provincial government itself should have authority over dictating a possible hierarchy of water uses, or if this type of policy-making should be left to regulatory bodies such as the EUB, or even the Environmental Appeal Board. In Capstone, the Director had to balance which licence holders should receive priority, which necessitated a consideration of the intended use of the water that was to be diverted.

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[87] *Supra* at note, s.2.
[88] EAB Appeal No. 03-116 and 03-118-121R (April 16, 2004) <http://www3.gov.ab.ca/eab/dec/03-116_118-121-R.pdf>.

Capstone's application to divert water from the Red Deer River for oilfield injection purposes had to be balanced against the interests of other licence holders, such as domestic or recreational uses. The question remains whether this type of decision should be made on a case by case basis, or if a more formal policy should be developed. Another issue is whether the existing regulatory regime currently is sufficient to regulate companies that may eventually find ways to economically treat saline water. If large quantities of treated water are produced, then is it open to the Crown as owner of all water in Alberta, to charge royalties for the use of the water if a company is able to sell this treated water to other users.

The MAC committee recommendation that criteria and guidelines need to be developed by AENV and the EUB should be carefully considered by the Alberta government. In light of the potential for water becoming a scarce resource in southern Alberta, provincial regulators should also reflect on the western U.S. experience in semi-arid areas.[89] This experience suggests that beneficial use of water for ranching and irrigation may not be appropriate in some cases due to the lack of a sustainable water supply.

As methane migration has created water and soil contamination problems in the western U.S.A., as recommended by the advisory committee, AENV and the EUB should investigate this issue to understand the potential for future problems. If the Alberta Government acts promptly on the advisory committee recommendations, residents will

[89] According to the Western Governors' BMPs, "long-term reliance on produced water should not be encouraged.", pp. 9-10; parts of southern Alberta are semi-arid.

have a much higher level of confidence that provincial water resources will be protected and maintained for future generations.

# Appendix 1

# Complete List of MAC CBM/NGC Recommendations

| Issue | # | Recommendation |
|---|---|---|
| **Water** | | |
| Improved Scientific Information | 3.2.1 | The following actions should be undertaken in collaboration with stakeholders to improve the scientific information on the province's water resources:<br>♦ AENV should expand its current monitoring network and data management system, beginning in areas that could experience intense CBM/NGC development.<br>♦ AENV should complete its inventory of groundwater in the province, beginning in areas that could experience intense CBM/NGC development. Coals containing non-saline water aquifers with potential CBM/NGC activity should be targeted. The inventory should include characteristics such as location, lateral extent, and porosity, as well as recharge rates and hydraulic connectivity between aquifers.<br>♦ The EUB and Alberta Geological Survey (AGS) should complete the Base of Groundwater Protection mapping project, beginning in areas that could experience intense CBM/NGC development.<br>♦ AENV and the EUB, together with industry, should investigate the potential for unintended effects of CBM/NGC development on surrounding aquifers.<br>♦ AENV should identify and characterize areas where CBM/NGC approval requirements need to be more rigorous due to potential impacts on non-saline aquifers, other water bodies and other water users. Maps of these areas should be made available to regulators, industry and stakeholders.<br>♦ Before drilling and production from a potentially non-saline aquifer where water volumes are anticipated to be above a threshold limit, CBM/NGC operators should obtain baseline data, including gas and mineral content and other indicators of water quality, flow rate/yield and water levels. In lower risk cases and below the threshold volume, less information may be required. The data would be included in a public database subject to confidentiality provisions. |
| Protecting Aquifers and Water Supplies | 3.3.1 | AENV should establish a multi-stakeholder technical committee to determine an appropriate, scientifically-based threshold volume for produced non-saline water below which a simplified approval under a Code of Practice for production or use of the water would apply. Threshold volume numbers should be developed for an individual well and on an areal basis. Interim threshold volume numbers should be established by AENV to ensure an effective and efficient process is available until the more detailed work is complete. In this regard, AENV provided a lower threshold volume number of 30 $m^3$/month/well and 100 $m^3$/month/section subject to the completion of supporting documentation and regulation if necessary. (The scientifically-determined numbers may be lower or higher than these values.) AENV should also establish a Code of Practice with stakeholder input. |

| Issue | # | Recommendation |
|---|---|---|
| | 3.3.2 | AENV and the EUB should develop a 'decision tree' approach for reviewing CBM/NGC applications involving non-saline water production. This process should address the level of risk to aquifers and users by considering factors such as hydrogeological settings, existing users, salinity and expected volumes of water produced. The decision tree should be developed with stakeholder input and should:<br>♦ Incorporate the threshold volume of produced non-saline water, below which the Code of Practice would apply (See Recommendation 3.3.1)·<br>♦ Consider geographical areas where the risk to the quality or quantity of water supplies might be greater than in other areas. It will be critical to know and understand those areas that may require special or additional attention from AENV. (See Recommendation 3.2.1)<br>♦ Ensure that applications for CBM/NGC wells that would produce volumes of non-saline water in excess of threshold volumes trigger accelerated aquifer studies.<br>♦ Ensure appropriate compliance with the decision tree. |
| | 3.3.3 | AENV's Guidelines for Groundwater Diversion for CBM/NGC Development (April 2004) should be enhanced and required for a single well or group of wells where non-saline water is present or anticipated.<br>♦ The guidelines should be reflected in the risk-based 'decision tree' process.<br>♦ To ensure consistency, minimum conditions for approvals should be standardized across the province, with additional site-specific conditions possible.<br>♦ The components of the field-verified survey of all water sources should be reviewed to ensure their appropriateness and effectiveness with regard to the scale of the project.<br>♦ A province-wide review of existing CBM/NGC wells should be undertaken to ensure all guidelines have been met. |
| | 3.3.4 | AENV should clarify and communicate the existing rules regarding how much drawdown is allowed during CBM/NGC depressurization in a confined non-saline aquifer to ensure aquifer protection. |
| | 3.3.5 | AENV and the EUB should work with stakeholders, including the environmental service industry, to develop standard procedures and reporting requirements for the sampling, analysis and monitoring of both saline and non-saline water quality and quantity for CBM/NGC wells and potentially affected non-saline water wells. Quality assurance and quality control measures should be developed, as well as a range of tests, depending on the type of water being tested, including:<br>♦ Testing for a variety of metals and other impurities, as well as total dissolved solids.<br>♦ Testing for the presence of gas in water wells. The presence or lack of gas should be included on the water analysis report or file. (See Section 3.6 for discussion on methane migration and release).<br>♦ Non-saline water produced from coal seams should be tested for its intended use or to determine what it can be used for. |
| | ***3.3.6*** | ***AENV and the EUB should develop a water well testing program, as follows:***<br>♦ ***CBM/NGC operators should be required to offer baseline testing*** |

| Issue | # | Recommendation |
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| | | ***(as described in Recommendation 3.3.5) of all nearby water wells within a specified distance of a proposed CBM/NGC well to be completed above the Base of Groundwater Protection. (No consensus was reached on an appropriate distance or depth of completion.)***<br>♦ ***The information from the baseline testing should be filed by operators in an open, public registry to enhance understanding of Alberta's groundwater system.***<br>♦ ***A clear process to address water well complaints should be developed and communicated to water well owners, surface rights holders and other stakeholders.*** |
| | 3.3.7 | AENV and the EUB should review drilling and completion practices for new and recompleted water and energy wells, ensuring regulations are appropriate for the purpose of the well. Topics to be addressed should include: drilling and completion fluids; well bore integrity/aquifer isolation; casing types; ***fracturing;*** and completions, etc. This review should include the drilling and abandonment of temporary water source wells. |
| Drilling Fluids | 3.4.1 | The EUB and AENV should communicate with CBM/NGC operators, drilling contractors and water well drillers regarding current and future requirements to protect non-saline aquifers. Action should be taken if there is evidence that an existing well has not met AENV's Guidelines for Groundwater Diversion for CBM/NGC Development (April 2004) (recommended for revision in Recommendation 3.3.3). Any company producing non-saline water from a CBM/NGC well without authority for a diversion above the threshold volumes should immediately stop operations and notify provincial regulators to initiate the authorization process. |
| | 3.4.2 | The EUB and AENV should, in cooperation with other organizations such as the Alberta Research Council, investigate whether CBM/NGC drilling and completion practices such as using dugout water and untreated river water may affect aquifers, and review regulations to determine whether changes are needed. They should also consolidate and review studies regarding drilling and completion fluid constituents and their potential for deleterious effects. |
| Promoting the Wise Use and Conservation of Water | 3.5.1 | AENV and the EUB, with stakeholder input, should:<br>♦ Review existing requirements for deep well disposal of non-saline produced water and consider alternatives, if appropriate.<br>♦ Establish criteria for the beneficial use of non-saline produced water.<br>♦ Develop guidelines, including a requirement for a beneficial use assessment for non-saline produced water and include them in the decision-tree approval process.<br>♦ Revisit authorized diversions of non-saline groundwater for industrial use when CBM/NGC developments create new sources of water in the area. |
| | 3.5.2 | AENV and the EUB, with stakeholder input, should establish criteria for the beneficial use of marginally saline produced water. AENV and the EUB, with stakeholder input, should then develop guidelines, including a requirement for a beneficial use assessment for marginally saline produced water, and include them in the decision-tree approval process. |
| | 3.5.3 | AENV, the EUB and Alberta Energy should work with the water producing |

| Issue | # | Recommendation |
|---|---|---|
| | | and environmental services industries to promote the development of new technology or the application of existing technology that can take advantage of saline and marginally saline produced water. |
| Methane Migration and Release | 3.6.1 | AENV and the EUB should work with industry to investigate the potential for methane migration or release to water wells as a result of CBM/NGC depressurization. |
| | 3.6.2 | Based on the results of the previous recommendation, AENV and the EUB should implement appropriate prevention, monitoring and mitigation measures to address methane migration or release, if necessary. |

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