MASTER OF PUBLIC POLICY CAPSTONE PROJECT

Review: Evolving Processes in Regulating Shale Gas Development in Alberta

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Executive Summary

Prior to the *Responsible Energy Development Act* (*REDA)*, environmental assessments and regulatory oversight responsibilities in Alberta's upstream energy sector (exploration and production of crude oil and natural gas) were carried out by multiple government agencies. Regulatory compliance was undertaken by each organization with limited co-ordination that increased regulatory duplication.[1] This led to the need and creation of a single regulator for upstream oil, gas, oil sands and coal development in Alberta, namely the Alberta Energy Regulator (AER). The goal is to create a less complex and more streamlined regulatory processes for project approvals and monitoring.

The advancements in technology such as the combination of multi-staged hydraulic fracturing (MHF) and horizontal drilling have made Unconventional Gas Development (UGD) possible in subsurface areas that were not economically viable or possible in the past. The UGD involves larger footprints, intense developments and last longer as compared to the conventional gas development.[2] Risks such as potential groundwater contamination, significant use of fresh water and cumulative effects to the landscapes have been linked to UGD.[3]

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[1] Energizing Investment A Framework to Improve Alberta's Natural Gas and Conventional Oil Competitiveness, 2010, Edmonton, Alberta: Government of Alberta (GoA), 17.

[2] Thomas G Measham and David A. Fleming, 2014, "Impacts of Unconventional Gas Development on Rural Community Decline." Journal of Rural Studies (6), 4.

[3] A Discussion Paper: Regulating Unconventional Oil and Gas in Alberta, 2012, Calgary, Alberta: Environmental Resources Conservation Board (ERCB), 8.

The AER's current regulatory approach regulates both the conventional and UGD the same way – activity by activity with a very little or no opportunity for collaboration between the operators to minimize the cumulative effects on the environment.[4] Alberta can no longer afford to manage UGD in an individual fashion, as such an approach makes it difficult to reconcile competitive demands and understand consequences of short-term actions in meeting longer-term objectives. Instead, we must consider cumulative impacts across the board.

In Sep 2014, the AER initiated a new regulatory approach – known as Play Based Regulation (PBR) pilot to test play declaration, play-based rules, project plans, and multi-well approval processes with the operators. The PBR is play-focused and allows for proactive and collaborative planning by operators within a play to minimize the effects of UGD. A play is a specific geographical area where the natural gas is believed to be found in an economical volume. The goal is to optimize timing of drilling and other separate and expansive operations (common suppliers, contractors, port, road, pipelines etc.). It also adopts a risk and performance based approach; addressing poor performing operators, and focusing greater resources and efforts on higher-risk activities.

This paper shows that PBR has the right approach to manage the cumulative effects of UGD. The following two approaches stand out a) single application (for orderly development and understanding the full scope of the project) and b) opportunity for collaboration (for shared development).

[4] Alberta's Oil and Gas Sector Regulatory Paradigm Shift: Challenges and Opportunities, 2015: Ernst & Young (EY), 6.

1. Introduction

In Canada, the production of conventional gas is progressively declining.[5] As these reserves have declined, a combination and technological improvement in MHF and horizontal drilling have made unconventional gas reservoirs such as shale gas (gas locked in fine-grained, organic – rich shale) development economically viable.[6] It is more challenging to recover gas from the unconventional reservoirs as compared to the naturally occurring conventional reservoirs.[7] This involves drilling techniques (vertical vs. horizontal), the fact that unconventional gas reservoirs are less mobile and the formations that hold them must be hydraulically fractured in order to liberate and acquire the gas molecules.

There is a huge potential of UGD in the west-central Alberta - Duvernay shale formation including condensate, which are used to move bitumen through pipelines.[8] However, there are new risks and challenges associated with this development, out of which following reasons stand out - (a) combination of horizontal drilling and MHF (reservoir rocks are cracked by injecting high volume of water, sand and some chemicals at very high pressure to create fractures in the rock and to hold the cracks open) and (b) intense scale of development occurring over large landscapes for longer period of time.[9]

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[5] A Primer for Understanding Canadian Shale Gas, 2009, Calgary, Alberta: National Energy Board (NEB), 1.

[6] Michael Dawson, Peter Howard and Mark Salkeld, 2012, Improved Productivity in the Development of Unconventional Gas: Productivity Alberta, 3.

[7] Craig C Douglas, et al., 2011, "Intelligent Fracture Creation for Shale Gas Development." Procedia Computer Science (4), 1745.

[8] R.P. Stastny, "Delving into the Duvernay", last modified 2013-Sep-17, accessed 02/09, 2015. http://www.oilweek.com/index.php/oil-and-gas-news/business/434-delving-into-the-duvernay.

[9] Environmental Impacts of Shale Gas Extraction in Canada: The Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction, 2014, Ottawa, ON: Council of Canadian Academies (CCA), 14.

1.1 Context

In Alberta, the conventional natural gas reserves are estimated to be around 31.9 Trillion Cubic Feet (Tcf). [10] At the same time, Alberta has extensive reserves of unconventional hydrocarbons and is particularly rich in unconventional natural gas, which is estimated to be 843 and 1,986 Tcf of gas.[11] The remarkable unconventional gas resources in the province can benefit energy – deprived countries such as Japan, India and Korea by exporting Liquefied natural gas (LNG) and Liquefied petroleum gas (LPG), thus providing economic benefits to Albertans.

Under the current regulatory approach, the AER approves each company's application separately for the individual energy development activity, with a very little emphasis given to the cooperative development and collaborations between participating operators.[12] This makes it difficult to appreciate the full scope of the project early, often resulting in multiple pipelines, roads, pads and other facilities required by individual operators. [13]

Alberta's regulatory framework has had to evolve to address these challenges, and provide Albertans with assurance that the system is effectively managing risk while ensuring efficiency for project proponents. To address this concern, the AER has launched a new initiative – play based regulation (PBR). The pilot is currently in operation in Fox Creek area of the Duvernay shale formation and will run for one year (see Appendix B). Under this pilot, operator within the play submits a single application

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[10] "Natural Gas," Alberta Energy, last modified Jan 2, 2015, accessed 05/17, 2015, http://www.energy.alberta.ca/NaturalGas/Gas.asp

[11] "Shale Gas in Canada: Resource Potential, Current Production and Economic Implications," Parliament of Canada, last modified Jan 30, 2014, accessed 01/20, 2015, http://www.parl.gc.ca/content/lop/researchpublications/2014-08-e.htm.

[12] Alberta's Oil and Gas Sector Regulatory Paradigm Shift: Challenges and Opportunities, 2015: Ernst & Young (EY), 6.

[13] A Discussion Paper: Regulating Unconventional Oil and Gas in Alberta, 2012, Calgary, Alberta: Environmental Resources Conservation Board (ERCB), 3.

for all the energy development activities as opposed to a separate application for an individual energy development activity.

The operators are encouraged to share project plans with other operators and increase the level of collaboration within a play. Under the current pilot, the collaborative approach between the operators is voluntarily. In this paper, I utilize existing literature to examine shale gas development and its impact on the environment. I review the regulatory and process information posted on the Alberta regulator website to examine the path of regulatory regime evolution in response to the increasing intensity and breadth of the UGD in Alberta. Finally, this paper compares the current regulatory approach with the new regulatory initiative and examines the changes in the regulatory design over five years in the context of UGD that are routinely dealt with by the AER.

1.2 Structure

This paper is organized in eight Chapters. Chapter 1 provides the background and context of this paper. Chapter 2 reviews the most recent changes in Alberta regulatory system, which ultimately led to the establishment of a single regulator for upstream oil, gas, oil sands and coal in Alberta. Chapter 3 presents the results of my literature review regarding UGD particularly shale gas development and its impact on the environment. Chapter 4 provides an overview of Alberta's current regulatory approach in regard to the UGD. Chapter 5 reviews the new regulatory initiative – PBR pilot; launched by the AER to manage the impacts of UGD such as shale gas. In Chapter 6, I analyze and compare the current regulatory approach with the new regulatory initiative – PBR pilot and present my findings. Chapter 7 and 8 includes conclusion and recommendations.

2. History of Alberta Regulator

Prior to analyzing the current regulatory approach and the new regulatory initiative, namely the PBR, it is appropriate to discuss the most recent changes in Alberta regulatory systems that ultimately led to the establishment of the AER as the single regulatory agency for upstream oil, gas, oil sands and coal development in Alberta. The AER now has the regulatory responsibility to oversee the exploration and development phases, through to facilities, reclamation and the public hearing process.

Prior to the *Responsible Energy Development Act (REDA)*, multiple agencies were responsible for the environmental assessment and regulatory performance. [14] They all issued approvals independently and regulating compliances at various project stages but with limited co-ordination and data sharing.[15] Each agency had their own system and performed their own application, environmental reviews with independent responses, which was not necessarily compatible with the systems used by other agencies. The Alberta Sustainable Resource Development (SRD), Alberta Environment (AENV) and Energy Resources Conservation Board (ECRB) were the three main authorities with the following regulatory responsibilities:

a) Alberta Sustainable Resource Development (SRD) was responsible for authorizations under the *Public Lands Act*. They were the regulator for activities requiring access to and occupation of public lands (e.g. well site, pipeline construction and operation). [16]

b) Alberta Environment (AENV) was responsible for authorizations under the *Water Act*

[14] Kirk N Lambrecht, 2014, "Constitutional Law and the Alberta Energy Regulator," Constitutional Forum Constitutionnel 23 (2), 36.

[15] Regulatory Enhancement Project Technical Report, 2010: Government of Alberta (GoA), 24.

[16] Ibid.,

and the *Environmental Protection and Enhancement Act* (EPEA).[17] They acted as the regulator for Alberta's air and water resources as well as the remediation and reclamation of oil and gas facilities.[18] AENV also shared responsibility for the *Conservation & Reclamation* (C&R) approvals under the EPEA with SRD; AENV being responsible for applications on the private lands, and SRD being responsible for applications on the public lands.

<u>c) The Energy Resources Conservation Board (ERCB)</u> was responsible for regulatory oversight of oil and gas development activities including well license authorization, application process, subsurface approvals and public hearing.[19]

There was frustration and concerns over compliance among the stakeholders (industry, farmers, ranchers, landowners) as they had to navigate through multiple agencies. Regulatory duplications, ineffective engagement, multiple applications were some of the problems faced by the stakeholders. The effective cumulative management was difficult to achieve due to the requirement to satisfy multiple regulatory agencies.[20] In 2010, the Regulatory Enhancement Task Force (RETF) suggested that an existing regulatory framework consisted of an overlapping legislative framework, inconsistent legislative application, overly complex approval processes and lack of collaboration between the regulatory agencies.[21] They recommended a streamlined and one-window - regulatory approval process for upstream oil, gas, oil sands and coal development in

[17] Under EPEA processes, designated activities may require an authorization, through a notice, registration, or approval. The processes followed: Authorization and Environmental Assessment

[18] Regulatory Enhancement Project Technical Report, 2010: Government of Alberta (GoA), 9.

[19] Ibid.,

[20] Nickie Vlavianos, 2012, A single Regulator for Oil and Gas Development in Alberta? A Critical Assessment of the Current Proposal, Calgary: Canadian Institute of Resources Law, 5.

[21] Enhancing Assurance - Report and Recommendations of the Regulatory Enhancement Task Force to the Minister of Energy, 2010, Edmonton, Alberta: Government of Alberta (GoA), 14.

Alberta.[22]

2.1 Alberta Energy Regulator (AER)

On June 17, 2013 the *REDA* was established, creating a single regulator to improve the Alberta regulatory system and increase competitiveness while providing high level of environmental protection and a strong commitment to the public health. Initially, the AER assumed the regulatory functions with the following six energy enactments:

- *Coal Conservation Act*
- *Gas Resources Preservation Act*
- *Oil and Gas Conservation Act*
- *Oil Sands Conservation Act*
- *Pipeline Act*
- *Turner Valley Units Operations Act*

By March 29, 2014, the AER had assumed all regulatory delivery functions for upstream oil, gas, oil sands and coal with the addition of certain specified enactments including:

- *Public Lands Act*
- *Water Act*
- *Environmental Protection and Enhancement Act (EPEA)*
- *Part 8 Mines and Minerals Act*

3. Unconventional Gas Development (UGD)

In Canada, the natural gas provides 30% of the energy needs and is largely used in the industrial, commercial, residential and electricity generation. [23] It is comparatively cleaner than the other fossil fuels such as oil and coal, producing less carbon dioxide

[22] Ibid.,

[23] Environmental Impacts of Shale Gas Extraction in Canada: The Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction. 2014, Ottawa, ON: Council of Canadian Academies (CCA), 18.

(about ½ that of coal). [24] The natural gas can be obtained from the conventional as well as the unconventional gas reservoirs. Unconventional gas such as shale is trapped inside the source rock due to the lack of permeability; pores are poorly connected that requires artificial fracturing for gas to escape out. [25] Shale gas is considered unconventional as it requires special technology such as the combination of MHF and horizontal drilling to be economically viable. On the other hand, conventional gas is found in the permeable rocks, which are fairly mobile and moves easily. [26] In permeable rocks, holes or pores are connected making it easier to extract the gas.

Today, Canada is one of the world largest producer and exporter of natural gas, which makes it vital to the Canadian economy.[27] Until recently conventional resources have been the primary source of gas production in Canada. However, after many years of production, conventional gas reserves are gradually declining. [28] Meanwhile, new unconventional gas resources such as shale gas have been discovered in Canada, including Alberta.

[24] Ibid.,

[25] Ibid., 17.

[26] Michael Ratner and Mary Tiemann, 2014, An Overview of Unconventional Oil and Natural Gas: Resources and Federal Actions: Congressional Research Service, 2.

[27] Environmental Impacts of Shale Gas Extraction in Canada: The Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction, 2014. Ottawa, ON: Council of Canadian Academies (CCA), 18.

[28] Ibid.,

Table 1: Shale gas reserves in the world

Rank	Country	Shale gas (Tcf)
1	China	1,115
2	Argentina	802
3	Algeria	707
4	U.S.	665
5	Canada	573
6	Mexico	545
7	Australia	437
8	South Africa	390
9	Russia	285
10	Brazil	245
	World Total	7,299

Source: http://www.eia.gov/analysis/studies/worldshalegas/

In Canada, the first shale gas development took place in the Montney shale formation in 2005, which was followed by the development in Horn River shale formation in 2007; both these formations are in northwestern British Columbia. [29] According to US Energy Information Administration (EIA) estimates, Canada has 573 Tcf of shale gas reserves (technically recoverable). [30] Unconventional gas resources include tight gas (found in low-permeability rock, including sandstone, siltstones, and carbonates), coal bed methane (CBM – gas contained in coal) and shale gas (locked in fine-grained, organic rick rock). According to the EIA, some 63% of Canadian production is expected to come from shale gas in 2035. The shale gas formations have been found in southern (densely populated) as well as north western part (sparsely populated) of Canada. [31]

[29] Christine Rivard, Denis Lavoie, René Lefebvre, Stephan Séjourné, Charles Lamontagne and Mathieu Duchesne, 2013, "An Overview of Canadian Shale Gas Production and Environmental Concern," International Journal of Coal Geology (126), 65.

[30] EIA/ARI World Shale Gas and Shale Oil Resource Assessment –Canada. 2013, Washington, U.S.: Advanced Resources International (ARI) and U.S. Energy Information Administration (EIA), 2.

[31] Environmental Impacts of Shale Gas Extraction in Canada: The Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction, 2014. Ottawa, ON: Council of Canadian Academies (CCA), 9.

3.1 Shale Gas Development in Alberta

There are 15 prospective shale gas formations that have been identified in Alberta. A recent report by the EIA estimates, five of these formations Alberta (Banff/Exshaw), E/W Shale (Duvernay), Deep Basin (Nordegg), N.W. Alberta (Muskwa), and S.Alberta (Colorado) may contain up 200.5 Tcf of technically recoverable gas.

Table 2: Shale gas reserves in Alberta

Region	Basin / Formation	Risked Resource In-Place		Risked Technically Recoverable Resource	
		Oil/ Condensate (Million bbl)	Natural Gas (Tcf)	Oil / Condensate (Million bbl)	Natural Gas (Tcf)
Alberta	Alberta (Banff/Exshaw)	10,500	5.1	320	0.3
	E/W Shale (Duvernay)	66,800	482.6	4,010	113.0
	Deep Basin (Nordegg)	19,800	72.0	790	13.3
	N.W. Alberta (Muskwa)	42,400	141.7	2,120	31.1
	S. Alberta (Colorado)	-	285.6	-	42.8
Total		**139,500**	**987.1**	**7,240**	**200.5**

Source: EIA/ARI World Shale Gas and Shale Oil Resource Assessment –Canada, page 3.

In 2012, shale gas operations in Alberta produced nearly 2.7 billion cubic feet (Bcf) of gas and the numbers of horizontal drillings have been on the rise.[32] In 2010 and 2011, more than two billion dollars were spent in leases in the Duvernay shale, making it the most active play in Alberta. [33] The current PBR pilot is taking place in Fox Creek area of the Duvernay shale formation (See Appendix C).

3.2 Technology used in Shale Gas Development

In Alberta, the hydraulic fracturing has been used since 1950s and horizontal drilling has been used since the late 1980s.[34] However, the game changer has been "the combination of these two technologies; the use of greater amounts of water, sand, and

[32]"Shale Gas in Canada: Resource Potential, Current Production and Economic Implications."
[33]EIA/ARI World Shale Gas and Shale Oil Resource Assessment –Canada, 33.
[34]Environmental Impacts of Shale Gas Extraction in Canada: The Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction, 38.

chemicals; and the higher injection rates and pressures to fracture a much larger volume of rock" [35] It is a proven technology commonly applied by the industry to safely recover gas from low permeability reservoirs such as shale. Hydraulic fracturing enables the production of gas from rock formations deep below the earth's surface, (an average of 7,700 feet) by using horizontal drilling and lateral fracturing to allow fluid injection to capture the gas, which could extend the well length between 1,000 to 6,000 feet. [36] During the fracking, a large quantity of water, proppant (usually sand) and chemical additives are injected at high pressure in the wellbore.[37] The pressure creates or widens fractures in the rock and the injected sand holds the crack open, allowing the gas or oil trapped in the water to flow into the wellbore. Fracturing is required to produce most shale, tight gas and oil in these kinds of formations.

Approximately 180,000 wells have been fractured vertically in Alberta since the technology was first introduced in the 1950s and over 7,700 wells have been drilled using the combination of two technologies - MHF and horizontal well drilling to enhance gas recovery. [38] Most shale formations targeted with MHF and horizontal wells operate thousands of meters below non-saline aquifers.

3.3 Impact of Shale Gas Development

There is a growing concern over shale gas development and the risks it may present to the environment and human health, which includes the significant use of water, cumulative impacts to the landscape, induced seismic activity, potential groundwater

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[35] Ibid.,

[36] Kate Kershner Kate, "How Hydraulic Fracking Works,", last modified Nov 13, 2012, accessed 12/09, 2014, http://science.howstuffworks.com/environmental/energy/hydraulic-fracking1.htm.

[37] Environmental Impacts of Shale Gas Extraction in Canada: The Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction, 14.

[38] "At A Glance," Alberta Energy Regulator (AER), last modified Jan 5, 2015, accessed 02/24, 2015, http://www.aer.ca/about-aer/spotlight-on/unconventional-regulatory-framework/at-a-glance.

contamination, air and noise pollution.[39] In Canada, three provinces Quebec, Nova Scotia and Newfoundland and Labrador have already issued fracking moratoriums.[40] The impact of shale gas development falls into three broad categories – Environmental, Economic and Social.

3.3.1 Environmental Impact

According to the Council of Canadian Academies (CCA) report *Environmental impacts of shale gas extraction in Canada*, there are three primary differences between the conventional and UGD such as shale gas, which lead to the much more higher environmental impacts: a) scale of development (larger impact on the local community) b) high volume of water and c) well integrity involving gas emissions and groundwater contaminations. [41]

3.3.1.1 Water Management and Protection

Common to the most upstream gas development activities, volumes of water being used in shale gas development are larger than the conventional gas development causing potential conflicts between the water users.[42] Lakes, rivers, shallow or deep sourced water wells, dugouts, sloughs are the primary water sources for the shale gas operations, which are also largely used by other stakeholders (farmers, ranchers). According to the Environmental Protection Agency (EPA) "the total volume of water required to drill a horizontal hydraulically fractured shale gas is estimated to be between 2 and 5 million

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[39] Risk Governance Guidelines for Unconventional Gas Development, 2013, Lausanne: International Risk Governance Council, 33.

[40] Kevin Bissett, "New Brunswick Introduces Fracking Moratorium," last modified Dec 18, 2014, accessed 03/02, 2015, http://www.theglobeandmail.com/news/politics/new-brunswick-introduces-fracking-moratorium/article22139797/.

[41] Environmental Impacts of Shale Gas Extraction in Canada: The Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction, 14.

[42] Ibid., 48.

gallons per well (from 7.6 to 19 million liters) depending on the depth, horizontal distance and number of times a well is fractured." [43]

In addition, there is a growing concern with the poorly designed well casing and waste water storage methods. Alberta's non-saline (fresh) aquifers are at very shallow depths, generally 100 and 300 meters below the ground.[44] The following recent incidents in Alberta, related to hydraulic fracturing and well bore integrity serve as an example:

a) "In September 2011 in Grand prairie, improper completion work (perforated casing above the base of groundwater protection, at a depth of 135m) was found to be the cause of contamination of near-surface water bearing sandstone with gelled propane" [45]

b) "In January 2012 in Innisfail, a spill occurred due to inter well bore communication, causing the release of about 500 barrels of fracturing and formation fluid to the surface, affecting 4.5 ha (majority of the cleanup operations were completed within 72 h)" [46]

The horizontal drilling takes place as the vertical well drilling reaches the depth of 1.5 to 4.0 kilometers.[47] During shale gas operations, the wastewater returning to the surface can contain contaminants (mixture of chemicals or absorbed from the rocks during the hydraulic fracturing). [48] About a quarter to a third of water used in the shale operations returns to the surface as a flow-back water, which is usually brackish (water in

[43] Dianne Rahm, 2011, "Regulating Hydraulic Fracturing in Shale Gas Plays: The Case of Texas," Energy Policy (39), 2975.
[44] Environmental Impacts of Shale Gas Extraction in Canada: The Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction, 62.
[45] Christine Rivard, et al., 2013, "An Overview of Canadian Shale Gas Production and Environmental Concern," International Journal of Coal Geology (126), 68-69.
[46] Ibid.,
[47] Environmental Impacts of Shale Gas Extraction in Canada, 44.
[48] "Regulating Hydraulic Fracturing in Shale Gas Plays: The Case of Texas.", 2975.

the pores is usually very salty) while the rest remains in the shale formation. [49] Shale gas is primarily composed of methane – CH_4 (more than ninety percent) and may have small amount of other gases such as butane, nitrogen, ethane, carbon dioxide, pentane and helium. [50] The primary risk to groundwater identified in the Canadian Council of Academics (CCA) report *Environmental Impacts of Shale Gas Extraction in Canada* is migration of methane gas from the wellbore either via fractures or flaws in the casing cements.

3.3.1.2 <u>Fracturing Fluids and Process</u>

A major risk to water supplies during hydraulic fracturing is the surface handling of completion and production fluids. Impoundments constructed to contain water for MHF operations and the flow back fluids can leak and be a source of surface and groundwater contamination. Fluid transfer operations and piping also present a risk pre and post – multi staged hydraulic fracturing.

Generally, 99% of fracturing fluids are fresh water while the remainder is usually proppant (mostly sands) and chemicals. "Some of the chemicals used in the fracturing fluids may include potassium chloride, guar gum, ethylene glycol, sodium carbonate, potassium carbonate, sodium chloride, borate salts, citric acid, glutaraldehyde, acid, petroleum distillate, and isopropanol". [51] These chemicals are used to make the hydraulic fracturing more effective and efficient thus improving the shale gas recovery process. "Critics allege that some of the substances used are hazardous materials and carcinogens,

[49] Survey of Energy Resources: Focus on Shale Gas. 2010. London, UK: World Energy Council, 17.
[50] Environmental Impacts of Shale Gas Extraction in Canada, 17.
[51] "Regulating Hydraulic Fracturing in Shale Gas Plays: The Case of Texas.", 2976.

toxics enough to contaminate ground water resources" [52] There are number of cases in the U.S where the residents have claimed their water to be polluted by these chemicals used in the fracturing fluids. In Alberta, there was one documented case where an aquifer was contaminated by MHF fluids. [53]

3.3.1.3 Seismic Events

The potential occurrence of seismic events is another concern related to the shale gas development. During the MHF and horizontal drilling, the fluids are forcefully injected to fracture the rocks creating thousands of micro-seismic occurrences; the injection process does not go for more than a few hours. [54] "Cases have been documented in Canada and elsewhere in which hydraulic fracturing was identified as the cause of unintended minor seismic events". [55] Early this year, two significant seismic activities were recorded in the Duvernay and Fox creek area. [56]

3.3.2 Economic Impact

"Due to the dispersed nature of this resource in the subsurface, the overall footprint or impact of UGD is generally larger than that of the conventional gas development, which is mostly concentrated in smaller areas (fields)". [57] UGD in the semi-rural and rural areas can bring rapid substantial changes due to influx of workers, trucks, traffics and noises. Common to shale gas development, well pads are larger, as well as drilling and completion activities on a well pads, pipelines, roads and other

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[52] Ibid.,
[53] Environmental Impacts of Shale Gas Extraction in Canada, 82.
[54] Ibid., 130.
[55] Ibid.,
[56] David Howell, "Fracking Possible Cause of 4.4-Magnitude Fox Creek Earthquake,", last modified Jan 31, 2015, accessed 01/18, 2015, http://www.edmontonjournal.com/Fracking+possible+cause+magnitude+Creek+earthquake/10775444/story.html.
[57] Risk Governance Guidelines for Unconventional Gas Development, 15.

production facilities can extend for longer periods of time impacting larger footprint. The public concerns are expected with respect to increased drilling near communities, increased pressure on infrastructure and the need to develop municipal services. Local governments also have to bear the costs of additional inspector / enforcement personnel to monitor heavy traffic and policing.

3.3.3 Social Impact

MHF and horizontal drilling operations can result in an increase in traffic from required transportation of equipment, water (flow back), materials as well as an increase in dust and air pollution. During MHF, substantial noise is also created as diesel engines and pumping equipment are used to generate the pressure required to fracture the rocks.[58] Frequent heavy truck traffic near school districts, hospitals and on the local highways are raising safety concerns. Similarly, the rapid and extensive scales of shale gas development can also having an impact on the agriculture, wildlife habitat and reduction in aesthetic beauty of the landscapes. [59]

Shale gas development involves intense and large scale activities such as …. Emission sources include "pad, road, and pipeline construction; well drilling and completion, and flow back activities; and natural gas processing, storage and transmission equipment" [60]

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[58]Environmental Impacts of Shale Gas Extraction in Canada, 47.
[59]Thomas G Measham and David A. Fleming. 2014, "Impacts of Unconventional Gas Development on Rural Community Decline," Journal of Rural Studies (6), 4.
[60]Michael Ratner and Mary Tiemann, 2014, An Overview of Unconventional Oil and Natural Gas: Resources and Federal Actions: Congressional Research Service, 9.

Table 3: Summary of Shale Gas Development Impacts

Environmental impacts	➢ Use of freshwater for hydraulic fracturing (loss of fresh water from the water cycle) ➢ Wellbore integrity - potential for contamination of potable surface and ground water (including domestic and multiple water wells) ➢ Hydraulic fracturing process includes chemical use, waste handling and disposal ➢ Air quality and seismic activity ➢ Larger footprint and intense development (causing loss and fragmentation of habitat / biodiversity) ➢ Need for higher grade all season gravel roads
Social impacts	➢ Public safety on dusty roads during peak truck traffic for hydraulic fracturing ➢ Noise, dust and light pollution ➢ Reduce aesthetic beauty of landscapes
Economic impacts	➢ Pressure on local and regional infrastructure due to the scale and the longevity of the shale gas development projects and influx of workers

4. Current Regulatory Approach

In Alberta "The regulatory system for UGD such as shale gas evolved directly from a well-functioning regulatory system that was already operating for conventional oil and gas projects."[61] Currently, both conventional and shale gas are regulated with a common approach and under the same rules, directives and legislation in Alberta.[62] Both conventional and shale gas development require separate applications for each activity such as drilling a well, building pipelines, facilities and the use of public lands and water.[63] Applicants must apply for a well license under a number of circumstances, which includes:

- a new oil or gas well
- a water well greater than 150m

[61] Risk Governance Guidelines for Unconventional Gas Development, 44.

[62] R. J Richardson 2013, North American Shale Revolution and Potential and Prospects of Shale/Tight Oil and Shale Gas Production in Alberta: Alberta Innovates - Energy and Environment Solutions, 8.

[63] A Discussion Paper: Regulating Unconventional Oil and Gas in Alberta, 2012, Calgary, Alberta: Environmental Resources Conservation Board (ERCB), 1.

- a new disposal or injection well
- re-entering a well or resuming drilling operations after original rig release

The well license forms the official record of the energy activity and includes information such as the well name and unique identifier, the name of the licensee, the surface and buttonhole location. Each well license application has associated consultation and notification requirements. A listing of these requirements can be found in the AER *Directive 056: Energy Development Applications and Schedules (*It provides the requirements and procedures for filing a license application under energy enactment, which covers facilities, pipelines and wells).

4.1 Ground Water Protection

The AER has strong regulations in place that are designed to protect groundwater. There are specific requirements for well drilling and completion, as well as for hydraulic fracturing operations, and the safe management of produced water. *Directives 008* and *009* provide requirements for casing, cementing and testing for ground water protection. *Directive 035* ensures compliance with the standard for baseline water-well testing for Coalbed Methane (CBM) / Natural gas and has been extended to areas where MHF and horizontal drilling are conducted.

Currently, the AER requirements prohibit the use of fracture fluids that may be harmful to groundwater quality when fracturing near a protected groundwater zone. No fluids, including those that have been treated, are ever allowed to be released into a surface water body. The AER restricts fracturing within a 200-meter lateral distance of water well to reduce the potential impact on or interference with domestic use aquifers or water wells. (*Directive 027: Shallow Fracturing Operations*).

In Alberta, the wellbores must have casing and cement integrity verified before hydraulic fracturing. [64]This requirement is combined with operating practices designed to minimize the risk of casing failure during hydraulic fracturing operations, which significantly reduces the risk of impacting shallow groundwater formations. Any produced fluids that are returned to surface must be handled, stored, and disposed of under the strict regulations of the AER.

4.2 Wellbore Integrity

The AER also has a number of directives in place to protect the subsurface and ensure wellbore integrity is maintained from the drilling and completion stage through operations until abandonment. The environmental concerns related to the communication of the wellbore with groundwater deal directly with cement casing. The AER has developed *Directive 083: Hydraulic Fracturing – Subsurface Integrity* to address the hydraulic fracturing risk to subsurface well integrity related to the UGD. The *Directive* 083 provides clarity on:

- Ensuring well integrity associated with hydraulic fracturing,
- Preventing inter-wellbore communication impacts, and
- Requirements for wells completed in shallow zones, which applies to any depths shallower than 100 meters below the base of groundwater protection (BGWP). [65]

This directive also include industry notification requirements for hydraulic fracturing activities and the need for immediate notice of a communication event where pressure or

[64] Christine et al., An Overview of Canadian Shale Gas Production and Environmental Concern, 72.
[65] "Directive 083: Hydraulic Fracturing – Subsurface Integrity," Alberta Energy Regulator (AER), last modified May 21, 2013, accessed 03/11, 2015, http://www.aer.ca/documents/directives/directive083.pdf.

fluid from a hydraulic fracture is observed at an offset well, non –saline aquifer or water well. Most recently, the AER has updated its *Directive 059: Well Drilling and Completion Data Filing requirements* to support its commitment to the transparent disclosure of fracture fluid information, including water volumes, water source, and types of chemicals used in a timely manner. The AER requires industry to report and justify the use of any fluid and other than water in a well, and to attach a list of fluids being used to the well license. The AER now requires disclosure of the ingredients in fracture fluids on a well-by-well basis.

4.3 Fracture Fluids

The AER uses www.fracfocus.ca to provide public access to chemicals and additives, volume and concentration as well as carrier fluid water volumes information used in MHF and horizontal drilling operations (See Appendix D). This enhanced reporting has been applied to all the hydraulic fracturing operations as of December 31, 2012. Industry must report within 30 days of completing a hydraulic fracturing operation. It is modeled after a similar website in the United States – www.fracfocus.org.

4.4 Seismic Events

The Alberta Geological Survey (AGS) of the AER has been monitoring seismic activity in Alberta for decades. In 2009, the AGS initiated the Induced Seismicity Project to document induced (or triggered) seismic events in Alberta.[66] Alberta has an extensive seismic monitoring program. Real-time monitoring of seismic events is helping with the development of a database of recorded seismic events that can be used for further analysis. Due to the most recent seismic activities in Alberta, the operators are now

[66] Induced Seismicity Project. 2011. Edmonton, Alberta: Alberta Geological Survey (AGS), 1.

required to report earthquakes even for 2.0 magnitudes, which they did not have to report before. [67]

Currently, the AER has 60 directives (in effect) to govern energy resource development in Alberta. Of these, following directives are specific to shale gas development activities, such as MHF and horizontal drilling technology:

- *Directives 8 and 9* provide requirements for casing, cementing and testing. This directive sets provide the last line of protection of subsurface strata from wellbore fluids
- *Directive 20* ensures proper well abandonment that plays an important role in control of nearby wellbore activity. MHF and horizontal drilling may result in high-pressure communication with offsetting wellbores, including abandoned wells
- *Directive 35* ensures compliance with the Standard for Baseline Water-Well testing.
- *Directive 38* establishes noise guidelines
- *Directive 44* regulates hydrocarbon production above the BGWP. Hydrocarbon production above the BGWP, along with CBM and MHF, is a recurring stakeholder concern
- *Directive 50* regulates drilling waste management and disposal. The land spreading while drilling is a continued practice where drill cuttings from a water-

[67] Sheila Pratt, "Oil and Gas Companies must Report Earthquakes near Fox Creek, New Rules Say," Edmonton Journal, last modified Feb 19, 2015, accessed 01/21, 2015, http://www.edmontonjournal.com/companies+must+report+earthquakes+near+Creek+rules/10827140/story.html.

based mud system are spread on cultivated lands. This has generated public concern and environmental impact on occasion

- *Directive 51* provides classification, approval process, operating parameters, technical requirements (cement, casing depth, casing condition and confirmation of wellbore integrity) and injectivity test requirements for all the injection and disposal wells
- *Directive 55* regulates storage requirements for the upstream industry, including associated wastes
- *Directive 55(A)* Requirements for large, open-top water storage “fracturing tanks”. The use of large open tanks has become the norm in unconventional production areas (Duvernay and Montney). These tanks are used to store water (fresh or saline) prior to fracturing and flow back water after the fracturing. Such large storage tanks have failed in the past, generating risk to workers and the environment
- *Directive 56* sets the proximity requirements for oil and gas wells from residential structures. It provides the requirements and procedures for filing a license application under energy enactments, covers facilities, wells and pipelines
- *Directive 59* regulates well drilling and completion data filing requirements that also include fracturing fluids and proppant types
- *Directive 60* regulates gas flaring, venting and incinerating

- *Directive 83* is a requirement for managing subsurface integrity associated with MHF that includes the subject well, offset wellbores, aquifers, water wells and surface impacts. [68]

All these above directives help to manage the impact of shale gas development activities such as potential groundwater impacts, chemicals used in hydraulic fracturing, subsurface contamination, flow back water, gas emission, noise pollution etc. However, this paper finds that the current regulatory approach is not well positioned to manage the cumulative impacts of shale gas development.

5. Unconventional Regulatory Frame-work (URF)

With unconventional resource activity such as shale gas drilling increasing in the Duvernay and Montney formations, a number of concerns are being raised by Albertans, industry and other stakeholders related to the potential implications of such development. In response, the Government of Alberta (GoA) has been working on a number of initiatives to ensure responsible development of these resources as part of its commitment under the Integrated Resource Management System (IRMS). The IRMS is a big – picture initiative that considers the overall environmental, economic and social outcomes of resource development. Successful implementation of this system will require strong working relationships with numerous ministries, organizations and other stakeholders.

In 2012, the ERCB published the Unconventional Resource Framework (URF) discussion paper *Regulating Unconventional oil and Gas in Alberta*. The paper identified

[68] "AER – Directives," Alberta Energy Regulator (AER), accessed 02/11, 2015, http://www.aer.ca/rules-and-regulations/directives.

several unconventional resource challenges including: water management and protection, high pressure hydraulic fracturing, development planning and community engagement. The URF identifies the unique threats, challenges and opportunities, which are associated with the unconventional gas development such as shale. It uses a science-based initiative to organize risks, recognizes regional impacts and addresses them at a play level (project by project) rather than well-by-well or activity-by-activity. It supports early stakeholder engagement, protects water, minimizes surface impacts, and maximizes resource recovery. Guided by this, in Sept 2014, the AER launched a new regulatory initiative - the PBR pilot to regulate UGD such as shale gas in Alberta.

5.1 Play Based Regulation (PBR) Pilot

The PBR Pilot is intended to test a single application and approval process for the various approvals granted (i.e. surface, sub-surface, water permitting / licensing) to develop a sound process and provide operational flexibility to the single operators as well as multi-operators.[69] The intent is to encourage operators to move from a well by well or activity by activity initiative to a project initiative looking at multiple wells and activities as part of one submission. It addresses regional aspects of unconventional resource development.

In terms of performance measures and compliance, the operators will report on their performance and the objectives they are trying to meet. The operators are asked to test defined performance measures and make the report of these publicly available. It is based upon two key principles: a) risk based approach and b) play focused approach.

[69] Manual 009: Play-Based Regulation Pilot—Application Guide, 2014, Calgary, Alberta: Alberta Energy Regulator (AER), 3.

5.1.1 **Risk Based Approach**

The regulatory response is related to the level of risks associated with the energy development activities. As a part of an application process the operators are asked to provide risk management plan that identifies hazards, risks assessed and mitigation proposed.[70] The response is to move away from the restricted view and monitor operator actions based on the dangers and hazards of energy development undertakings. The intent is to be clearer on the risk management needs, then increase monitoring accordingly. The unconventional resource such as shale gas is distributed over the large area of land as compared to the conventional gas play which is focused in small areas.[71]

5.1.2 **Play Focus Approach**

In an area-based initiative regulatory processes are tied to a play growth, pressures on the landscape, resources and community in order to achieve the environmental, economic and social outcomes.[72]

Table 4: Shale reservoir properties in Alberta

Shale Play	Drilling Depth	Shale Thickness
Duvernay	7,500 feet in the east to 16,400 feet in the west	30 to over 200 feet
Nordegg	3,300 feet in the NE to 15,000 feet in the south	50 to 150 feet
Muskwa	3,300 feet in the NE to 8,200 feet in the SW	33 to 200 feet
Colorado	5,000 feet in the east to over 10,000 feet in the west	300 feet to 1,000 feet

Source: EIA/ARI World Shale Gas and Shale Oil Resource Assessment –Canada, 30.

As shown in table (4), there is a huge variation in shale reservoir properties (drilling depth and shale thickness) among the shale formation in Alberta. The play characteristics

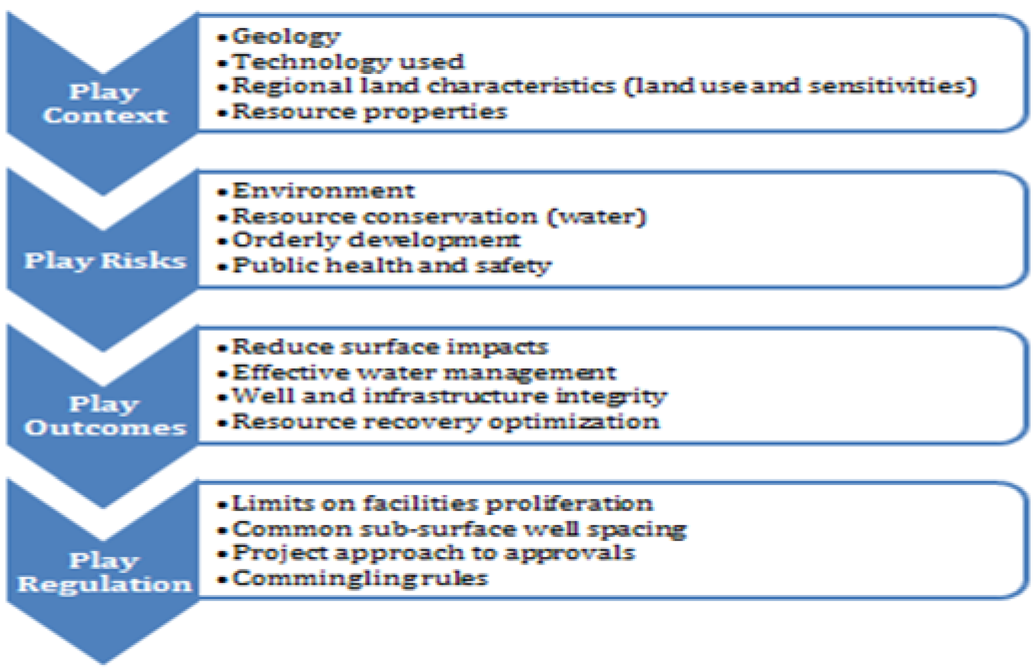
[70] Ibid., 1

[71] Michael Dawson, Peter Howard and Mark Salkeld, 2012, Improved Productivity in the Development of Unconventional Gas: Productivity Alberta, 47.

[72] Manual 009: Play-Based Regulation Pilot—Application Guide, 1.

are not uniform across geographical areas and are based on unique qualities creating different quantities and concentration of technically recoverable resources such as shale gas, condensate etc. This initiative tests an area-based planning through a project initiative and a single application to facilitate multiple approvals. Plays are defined by geology (depth and thickness of the shale composition), technology (water quantity, chemicals used during MHF and horizontal drilling) and resource (ground water and fertile land). According to the report *Risk Governance Guidelines for Unconventional Gas Development* "Different regulations and safeguards area are required in different geological and geographic settings"[73]

Fig 1: New regulatory initiative – PBR pilot



Source: Manual 009: Play-Based Regulation Pilot—Application Guide.

As shown in the figure (1), the key objectives of this new regulatory approach are: a) encourage early project or play-based planning with increased collaboration amongst

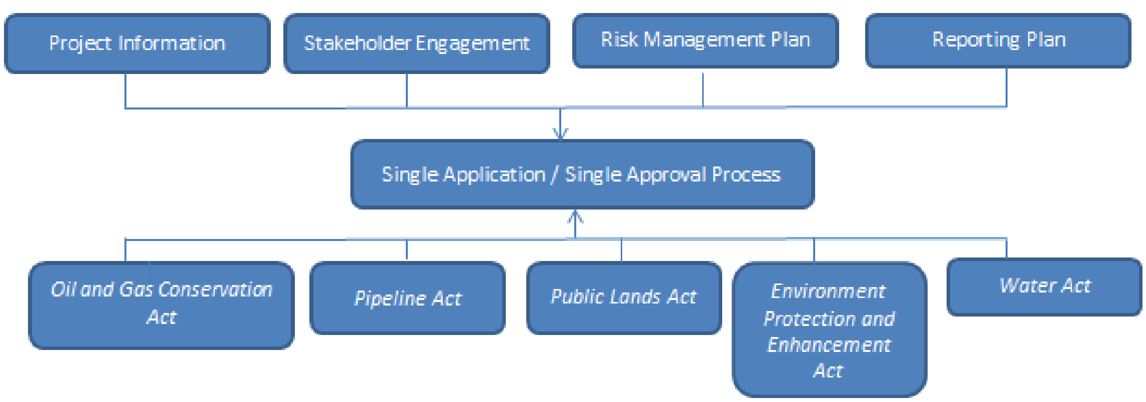
[73] Risk Governance Guidelines for Unconventional Gas Development, 46.

the operators b) community engagement c) effective water and waste management, and d) more outcome/performance-based regulations where appropriate.

5.1.3 <u>Single Application</u>

During the PBR pilot, the AER will be accepting a single project application for the multiple energy development, which may include many activities governed by different pieces of legislations.[74] The Pilot has been extended until September 30, 2015. Stakeholders will have an opportunity to be involved earlier in the planning stages of proposed energy development, allowing the energy industry, stakeholders and the regulator to understand the project scope clearly. The single application includes the full lifecycle of the project plan (project information, stakeholder engagement plan, risk management plan and reporting plan).[75]

Fig2: Single Application and Single Approval Process under the PBR pilot



Source: Manual 009: Play-Based Regulation Pilot—Application Guide.

<u>a) Project Information-</u> the applicant describes the entire project development and establishes the context for the risk management (*ISO 31000*) as well as the stakeholder

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[74]Manual 009: Play-Based Regulation Pilot—Application Guide, 7.
[75]Ibid.,

engagement.[76] Project plan concept creates opportunities to streamline subsequent application and approval process for well, facilities, holding and water licenses.

b) Stakeholder Engagement- the applicant describes their planned activities with the stakeholders (aboriginal group, ranchers, farmers, landowners) throughout the shale gas development project.[77] An early and effective stakeholder engagement involves a) stakeholder consultation on the project plan and b) identifying issues and addressing throughout the entire project.

c) Risk Management Plan- the applicant describes how it is going to identify risks associated with the shale play and effectively manage them by:

- Defining the context (internal and external)
- Identifying the risk sources, threat, events and consequences. These are based on the geology, technology and nature of the resources.
- Analyzing the risk in a given area, management measures, risk matrix, threat and consequences categories
- Evaluating the risk - Options to address the risks such as temporal allocations, standards , administrative procedures
- Treating or managing the risk – Implementation of the management measures in terms of accountability, functions and activities

d) Reporting Plan- the applicant completes compliance verification, performance auditing and reporting (monitoring) of the project activities. The plan for monitoring and reporting of groundwater and surface water must include a baseline assessment and ongoing monitoring and reporting of changes in water

[76] Ibid., 8.
[77] Ibid.,

quantity, to ensure that outcomes are achieved. In addition, the reporting plan also help to evaluate operator's performance in achieving the objectives of PBR pilot and overall GoA policy outcomes.[78]

5.1.4 **PBR Objectives:**

Alberta has a number of provincial-level strategies designed to clarify direction and recognize integrated outcomes (coordinated approach to better understand the impact of development has on the environment and communities). While the Land Use Framework (LUF) explicitly references cumulative effects management, its philosophy is engrained in other provincial level strategies such as water for life, biodiversity strategy and clean air strategy. The PBR shows alignment with these regional strategies and policies. "The pilot is a test of a new AER regulatory process for implementing GoA policy and represents the start of a change in the way that the AER regulates the energy sector: from activity-by–activity regulation to the regulation of multiple activities across large areas".[79]

The PBR has identified five issues, which the applicants have to address how they are going to process in order to achieve the following outcomes: a) water management b) surface infrastructure c) subsurface reservoir management d) stakeholder engagement and e) life- cycle wellbore integrity. The PBR's main objectives are as follows:

- Mitigate risks to resource conservation, public safety, environment and ensure orderly development by recognizing regional impacts and addressing them at a play level rather than well-by-well or activity by activity

[78] Manual 009: Play-Based Regulation Pilot—Application Guide, 15.
[79] Ibid., 2.

- Include assessments of where hydraulic fracturing is likely to occur and identify areas this activity might conflict with other land uses or sensitive ecological areas of wildlife
- Use of multi-well pads (moving to drilling greater portion of wells from a common pad) and other shared infrastructures (road, pipelines) to reduce any surface impacts
- Predict number of wells, facilities, access road and pipelines that will be needed for the entire area / play
- Proactively engage stakeholders, locals regarding expectations – water management, dust, trucking and other nuisance issues and work together to address those concerns

5.1.5 PBR Pilot Area

The PBR pilot is taking place in Fox Creek area of Duvernay shale formation that consists of approximately 140 townships in size (See Appendix C). The area includes caribou habitat as well as important sources of water for local communities. "The depth of the Duvernay shale increases from east to the west; ranging between 1000m in the east to about 5500 m in the west and this variation in burial depth created various stages of hydrocarbon generation including oil, condensate and dry gas zones from east to west".[80] Geographically, the Duvernay play covers about 100,000 square kilometers (38,600

[80] Amin Ghanizadeh et al., 2014, " A Comparison of Shale Permeability Coefficients Derived using Multiple Non-Steady State Measurement Techniques: Examples from the Duvernay Formation, Alberta (Canada) " Fuel (140), 4.

square miles) across the greater Kaybob and Pembina areas in Alberta. [81] The resource development in Duvernay formations are in their early stage, however it has a potential to become the most significant resource play in Alberta.

6. **Findings**

According to DM Franks, “Cumulative impacts can result from the aggregation (over time or space) and interaction of the impacts of a single activity, notwithstanding that in most cases cumulative impacts will arise as a result of multiple activities and will often involve multiple actors”. [82] The cumulative effect management includes economic (sustainable prosperity supported by land and resources), social (livable communities) and environmental (healthy environment and ecosystem). An escalating scale of development and increase water use and other infrastructures should be evaluated not by well by well or activity by activity but in the regional context with appropriate regulatory initiative. [83] The cumulative effects of the shale gas development include environmental impact, destruction of the First Nation’s land and pressure on the municipal services and infrastructure.[84]

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[81] Gordon Jaremko, "Duvernay is Proving Ground for Canadian Regulatory Reform,", last modified July 18, 2014, accessed 01/19, 2015, http://www.naturalgasintel.com/articles/99064-duvernay-is-proving-ground-for-canadian-regulatory-reform.

[82] Daniel M Franks, David Brereton and Chris J. Moran, 2013, "The Cumulative Dimensions of Impact in Resource Regions," Resources Policy (38), 642.

[83] Robert G Boutilier and Leeora Black. 2013, "Legitimizing Industry and Multi-Sectoral Regulation of Cumulative Impacts: A Comparison of Mining and Energy Development in Athabasca, Canada and the Hunter Valley, Australia," Resources Policy 38 (4), 699.

[84] Ibid.,

Table 5: Comparison (Current Regulatory Approach Vs. New Regulatory Initiative – PBR)

Current Regulatory Approach	New Regulatory Initiative - PBR
Separate application for an individual project activity	Single application for the entire project activity
Well focus (permit for an individual activities – well by well)	Regional play focus (permit - project by project)
Reactive – Prescriptive based regulatory model	Proactive – Performance based regulatory model (focus field inspections on higher risk activities)
Granting permits to facilities one at a time (single entity license approvals)	Granting permits for the entire projects involving multiple wells and operating sites (pad / project license approvals)
Single operator performance	Combined operator performance
Data by well / pool	Data by pad/ project / play / area
Management by well / pool	Management by play / area
Little emphasis on collaboration between operators	High encouragement on collaboration between operators by allowing integration land use activities
Stakeholders engagement on the well by well basis	Stakeholders engagement on the entire project plan
Stakeholders only get a snapshot of the project plan	Stakeholders get the full scope of the entire project plan
Multiple approvals under individual energy and environmental enactments (more regulatory burden)	Single approval under all the applicable energy and environmental enactments (less regulatory burden)

Source: www.aer.ca

As shown in the table (5), this paper finds significant differences between the current and new regulatory approach, on how the regulator oversees UGD such as shale gas in Alberta.

6.1 Current Regulatory Approach

Currently, the AER regulates both the conventional and UGD such as shale gas the same way - activity by activity (well by well). The AER has 60 directives in effect, out of which following fourteen (14) are very specific to regulating shale gas operational activities (e.g. wellbore integrity, MHF, horizontal drilling, subsurface integrity, onsite storage of fluids, baseline water testing, and waste disposal).

- *Directive 8: Surface Casing Depth Requirements*
- *Directive 9: Casing Cementing Requirements*

- *Directive 20: Well Abandonment*
- *Directive 35: Baseline Water Well Testing*
- *Directive 38: Noise Control*
- *Directive 44: Surveillance of Water Production in Hydrocarbon Wells*
- *Directive 50: Drilling Waste Management*
- *Directive 51: Injection an Disposal Wells*
- *Directive 55: Storage Requirements*
- *Directive 055(A): Addendum: Interim Requirements for Aboveground Synthetically – lined wall storage systems, updates to liner requirements, and optional diking requirements for single walled aboveground storage tanks*
- *Directive 56: Energy Development Applications*
- *Directive 59: Well Drilling and Completion Data Filing Requirements*
- *Directive 60 Upstream petroleum industry flaring, incinerating, and venting*
- *Directive 83 – Hydraulic Fracturing – Subsurface Integrity.* [85]

All these directives (See Appendix A) support the safe and responsible development of shale gas resources and help to maintain quality of life in Alberta. According to the report *Risk Governance Guidelines for Unconventional Gas Development* "several factors are unique to the development of unconventional gas resources and require special attention by regulators".[86] I find that the current regulatory approach is not effective in managing the cumulative effects of shale gas development. My conclusion is based on two primary observations:

(a) Lack of collaborative approach between operators

Each operator develops their own facility required for shale gas operation such as – building road, drilling well and pipeline construction independently. This makes it very difficult to reduce the cumulative environmental effects of the additional road, pipelines, well pads required by individual operator in the specific region. Each project impacts its surroundings (water resource, noise, road, visual amenity, vehicles, pipelines, dust, noise, vibration), which might be acceptable individually. However,

[85] "AER - Directives."

[86] Risk Governance Guidelines for Unconventional Gas Development, 48.

the combination of multiple projects and the cumulative effects will easily cross the particular limit or threshold impacting the community and biodiversity. [87]

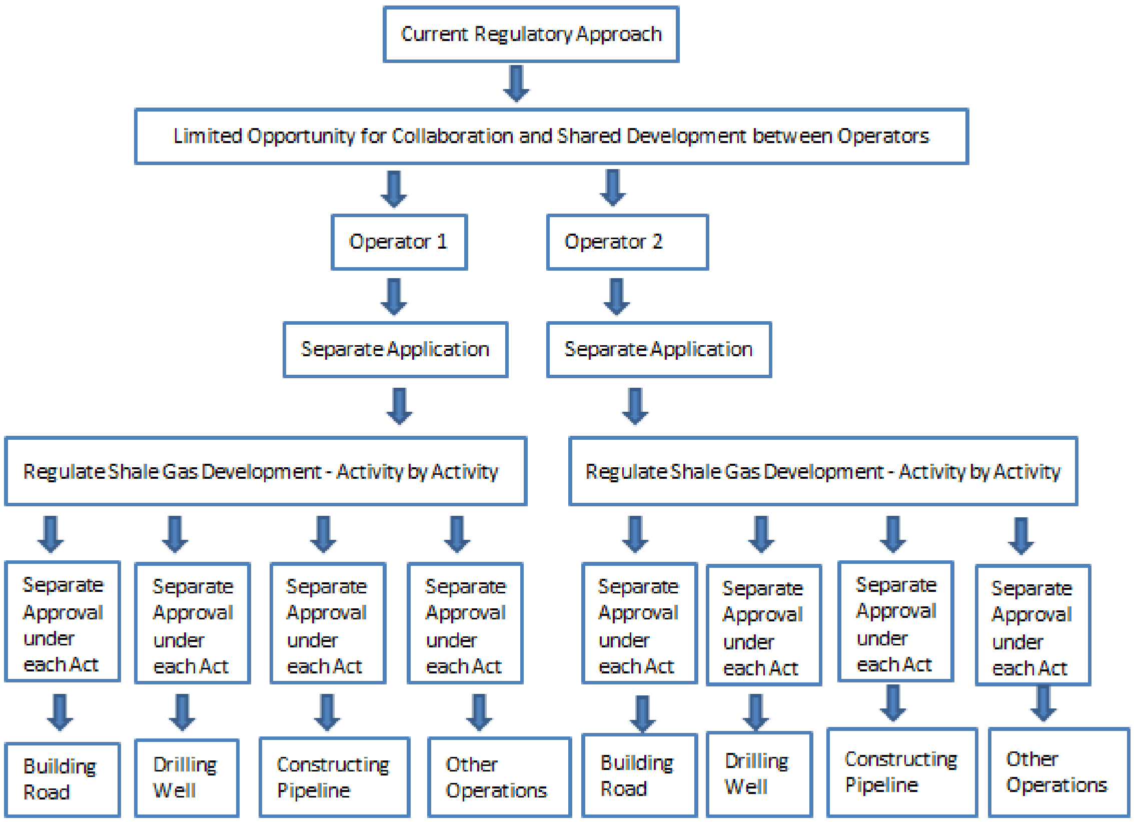
(b) Regulating shale gas development by activity

Each operator submits separate application for an individual shale gas activity such as – building road, drilling well, constructing pipeline, diverting water, building well pads etc. The regulator and stakeholders do not get the full picture of the shale gas development. This makes it difficult to capture the full scope of the project earlier on and assess any cumulative effects within a play, which is defined by geology, technology and resource.[88] Operations that result in frequent or continuous odor, traffic, dust and or noise threaten the social well-being of a community and significant impact to the human health.

[87] Daniel M Franks, David Brereton and Chris J. Moran, 2013, "The Cumulative Dimensions of Impact in Resource Regions," Resources Policy (38), 642.

[88] Cumulative impacts are the combined effects of past, present and foreseeable human activities, over time, on the environment, economy and society in a particular place

Fig 3: AER – Current Regulatory Approach



In the current regulatory approach there is a limited opportunity for collaboration between the operators as energy developments are authorized individually – activity by activity; as a result the cumulative effects of shale gas are not properly addressed. [89] In addition, each operator submits separate applications for an individual activity such as – building production facilities, drilling wells, pipelines, and access roads. This makes getting the full picture of the project beforehand difficult for the stakeholders (farmers, ranchers, landowners, aboriginal group, regulator and municipality). Due to this there are fewer opportunities to identify suitable locations (with the stakeholders), maximize and share existing infrastructure (pipelines, roads, production facilities) as well as work with

[89] Alberta's Oil and Gas Sector Regulatory Paradigm Shift: Challenges and Opportunities, 6.

the municipalities on planning infrastructure to reduce incremental disturbances and impacts on a community and land surfaces. [90]

6.2 New Regulatory Initiative (PBR)

As compared to the current regulatory approach, the new initiative - PBR moves beyond cookie-cutter delivery approaches and tailor approaches to the circumstances within a play, requiring a suite of regulatory and non-regulatory mechanisms. It helps to better coordinate the UGD such as shale, which includes large and intense scale activities over extended period of time. Under this new approach, the participating operator submits a single application for all the shale gas related activities within a specified play. The stakeholders are engaged early on and get a clear picture of the project. The participating operators are encouraged to collaborate on water management plans as well as common infrastructure (joint – access roads, pipelines, pads, water resources, leases and other infrastructure). These activities help to minimize development footprints, traffic, air pollution noise and spills thus reducing cumulative effects on the ecosystem and community.

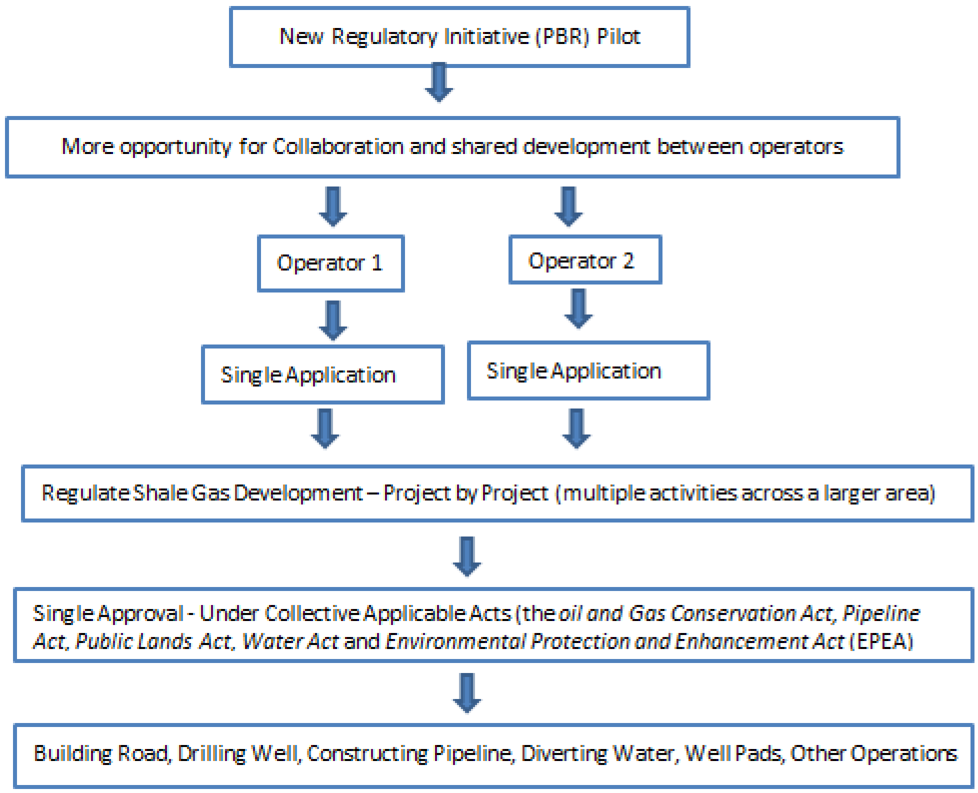
The Devon case study shows the following benefits of coordinated approach and shared development (using multi- well pads):

- Cumulative foot print was as much as 50 to 70 % smaller
- Minimize the need to truck in large cranes and large crews for rig moves (Reduces spills)
- Reducing road building by 40- 50 %
- Reduces lines from wells to processing tanks by 70 – 80% (Eliminate stream and road crossing , reduces trenching and surface line)
- Reduces truck traffic by 30-60%
- Better spill prevention/containment methods and faster response on emergency operations

[90] A Discussion Paper: Regulating Unconventional Oil and Gas in Alberta, 25.

- Flow-back water treated in a centralized treatment facility, minimizing spill potential, truck traffic.[91]

Fig 4: AER – New Regulatory Initiative (PBR)



"The PBR marks a shift towards approval of full life cycles for entire projects or programs involving multiple wells and operating sites spread out across swaths of territory – a sharp departure from traditional practices of granting permits to facilities one at a time "[92] The PBR provides easier integration of land use activities such as road, well, pipelines, pad, etc. minimizing linear disturbances. Drilling greater portion of well from a multi-pad helps to minimize the footprint of development, which is clearly demonstrated by the following examples: [93]

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[91]Dawson and Howard, Improved Productivity in the Development of Unconventional Gas: Productivity Alberta, 38-39.
[92]Jaremko, "Duvernay is Proving Ground for Canadian Regulatory Reform."
[93]A Discussion Paper: Regulating Unconventional Oil and Gas in Alberta, 12.

- Placing several wells on one site reduces the impact on developable land, which is especially important in populated areas.
- Reduces surface disturbance by eliminating the need for additional lease roads and pipelines.
- Multi-well pads are far more efficient because once a well is drilled the rig moves only 20 feet or so to drill the next one, reducing truck traffic.
- In rural areas, producers can be more flexible about where to place its wells, which gives landowners more input on placement of the wells and the construction of the road leading to those wells.
- The number of storage tanks and liquid separators can be lowered by consolidating the operations of multiple wells onto one pad decreasing the surface disturbance, traffic and minimizing spills. [94]

The stakeholder's involvement in play identification, risk profile considerations and subsequent implementation phases of shale gas development is critical to PBR success. "As illustrated by the large public acceptance of UGD in Poland, understanding and familiarity can increase community acceptance, industry accountability and investment in the area, and contextualizes regulatory decisions"[95] Ernst & Young report, *Alberta's oil and gas sector regulatory paradigm shift: challenges and opportunities* summarizes - PBR as an improved regulatory initiative , which reduces regulatory duplications, encourage innovations, provides predictability and manage cumulative effects of unconventional resources. The collaborative approach not only helps to manage risks but also maximize economic efficiency. The operators will be able to bring their operational cost down by sharing road, pipelines and other infrastructures.

[94]Dawson and Howard, Improved Productivity in the Development of Unconventional Gas: Productivity Alberta, 29-30.
[95]Risk Governance Guidelines for Unconventional Gas Development, 55.

7. **Conclusion**

The production of conventional gas has been gradually declining in Canada. However, there are abundant supplies of unconventional gas resources in Canada that can substitute to satisfy natural gas demand. The development of shale gas requires a commitment of time, infrastructure and development activity that increases the risk of cumulative impacts on water, land and air resources.[96] Planning for this type of resource development, granting permission, and overseeing development requires a dedicated, ongoing regulatory program. As with other institutions, the regulation and oversight of natural reserves has evolved over time in Alberta, which led to the establishment of a single regulator – the AER.

The AER has the necessary directives (see Appendix A) in place to regulate any activities specific to shale gas development. However, the current regulatory approach is not well suited to manage the cumulative effects of shale gas development effectively because it encourages limited collaboration between the operators and does not evaluate the full scope of the project development and its impact.

Coordinated development of a play, if managed effectively, will minimize the cumulative effects of shale gas development. The new regulatory initiative – PBR is based on two principles: (a) risk based (the highest risk activities require the most diligent oversight) and (b) play focused (tailored to the resource play). It encourages cooperation between operators from the early stages of the development to minimize infrastructure duplication (pipeline, road, well, pad, water management) and effective use of resources

[96] Brian G Rahm and Susan J. Riha, 2012, "Toward Strategic Management of Shale Gas Development: Regional, Collective Impacts on Water Resources," Environmental Science and Policy 17: 12-23.

for a long-term use. The new regulatory initiative is proactive and engages stakeholders early in the process of monitoring for new plays, identifying the risks associated with those plays and considering the regulatory outcomes to mitigate those risks.

This paper concludes that the new regulatory initiative - PBR - is a good example of how AER is adapting regulations to new developments, technology and challenges; taking in to energy development activities on a broader scale, which allows better understanding and mitigating the cumulative impacts of shale gas development.

8. Recommendations

The success of the play-based regulatory approach cannot rely entirely on voluntary measures to achieve the requisite level of cooperation. Under the current PBR pilot, a cooperative approach between industry players is on a voluntary basis as a result successful collaboration among operators in development of project plans may be difficult to achieve.

Oil and gas development by its very nature is a competitive business where each operator may deploy proprietary technology to maximize value for its investors and may not want to erode the competitive advantage of confidentiality of data by collaborating with other operators. Operators may be more interested in collaboration designed to enhance stakeholder engagement, certain aspects of water management and surface infrastructure development. However, on the other hand certain aspects of subsurface reservoir management are related directly to the competitive nature of the industry and operators may be less incline to collaborate.

Companies rarely control contiguous blocks of unconventional mineral rights. A declared play has the potential to extend over a vast area which presents to being manageable as a single entity. Each company is accountable to its shareholders and therefore the priority and timing for developing the mineral rights it holds under lease will depend on its view of the economics to develop that resource compared to other opportunities in its portfolio. These varying priorities, along with each company's unique capital constraints may result in one party wanting to proceed with a development immediately with another may wish to defer the development to a later date. As a result, collaborative development strategies may not be their top priority.

In a competitive environment there is a risk that an uncooperative operator could easily delay other project development or the planning process of other operators. Cooperation and long-term system–wide perspectives is attainable with the following interventions by the AER:

- Providing strong incentives to operators to ensure the necessary level of cooperation
- Making collaborative approach among operators a mandatory requirements and provide mediation resources to operators, to ensure that all parties remain equally committed to the success of the development plan
- Providing greater clarity around the implications for operators who are not willing to participate in a collaborative manner. This would provide certainty that the AER will not allow operators to intentionally or unintentionally gain a net benefit over another based solely on their participation (or lack of) in the collaboration process

In the future, the AER should invite regulators from the other jurisdictions (British Columbia and Saskatchewan) to participate in the PBR sample of compliance activities. The invited regulators should be asked to provide suggestions and feedback to improve the PBR. This will provide an opportunity for the AER to improve the system and share information with other regulators regarding the PBR pilot.

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Appendix A: Current AER directives specific to the shale gas development

Directive	Name	Topics
008	Surface Casing Depth Requirements *(Dec 9, 2013)*	Design of surface casing depths to assist with well control and protect ground water resources Blowout preventers sit on top of the surface casing. Surface casing must be set below the base of groundwater protection as determined by the GoA Hydraulic fracturing and concerns related to communication of the wellbore with groundwater deal directly with surface casing In combination with Directive 009, this directive sets requirements that provide the last line of protection of subsurface from wellbore fluids
009	Casing Cementing Requirements *(July 1, 1990)*	Design of casing cementing programs to meet regulator and groundwater protection requirements. Procedures for confirmation of cement top and cement integrity, which includes all permanent cemented tubular in a wellbore: ➢ Surface casing (cemented to surface) ➢ Conductor Pipe (rarely cemented) ➢ Intermediate and production casing Hydraulic fracturing and concerns related to communication of the wellbore with groundwater deal directly with cement casing In combination with Direction 008, this directive sets requirements that provide the last line of protection of subsurface from wellbore fluids
020	Well Abandonment *(June 9, 2010)*	Regulates proper well abandonment that plays an important role in control of nearby wellbore activity. Hydraulic fracturing may result in high-pressure communication with offsetting wellbores, including abandoned wells. Proper abandonment of wells plays an important role in control of nearby wellbore activity
035	Baseline Water Well Testing *(May 8, 2006)*	Mandatory requirements for coalbed methane (CBM) wells completed above the GoA Base of Groundwater Protection (BGWP) There has been significant concern expressed regarding water issues in CBM areas and this has extended to areas where horizontal fracturing and horizontal drilling are conducted
038	Noise control	The directive provides noise guidelines to deal with noise

	(Feb 16, 2007)	problems.
044	Surveillance of water production in hydrocarbon wells *(July 14, 2011)*	Includes conventional and unconventional wellbore types (Oil sands inclusive). Requirements and processes related to all hydrocarbon wells with completions above the base of groundwater protection (BGWP) Hydrocarbon production above the BGWP, along with CBM and hydraulic fracturing, is a recurring stakeholder concern
050	Drilling waste management *(May 02, 2012)*	Regulates drill waste management, guideline includes sampling and analytical requirements as well as disposal standards and measures. Land spreading while drilling is a continued practice where drill cuttings from a water-based mud system area spread on cultivated lands
051	Injection on disposal wells *(March 1, 1994)*	Includes gas storage, steam injection, produced water disposal and industrial waste disposal wells Classification, approval process, technical requirements (casing depth, cement, confirmation of wellbore integrity and casing condition), operating parameters and injectivity test requirements for all injection and disposal wells
055	Storage requirements for upstream petroleum Industry *(Dec 1, 2001)*	Regulates storage requirements for the upstream industry, including associated wastes to prevent groundwater, surface water and soil from any contamination.
055(A)	Addendum: Interim Requirements for Aboveground Synthetically-Lined Wall Storage Systems, Updates to Liner Requirements, and Optional Diking Requirements for Single-Walled aboveground Storage Tanks *(Oct 10, 2011)*	Requirements for large, open-top water storage “fracturing tanks”. The use of large tanks has become the norm in unconventional production area (Duvernay formation). These tanks are used to store water (fresh or saline) prior to hydraulic fracturing and flow back water after the fracturing.
056	Energy development applications and Schedules *(May 1, 2014)*	Comprehensive main AER development application guide. Provides the requirements and procedures for filing a license application under energy enactments, which covers facilities, pipelines and wells
059	Well drilling and completion data filing requirements *(Dec 19, 2012)*	Provides guidelines on submitting daily reports on well drilling, well data, and abandonment data. The report also include information on fracturing fluids and proppant types that are used during the MHF

060	Upstream Petroleum industry flaring and venting *(May 1, 2014)*	Regulates flaring, venting and Incinerating at the upstream energy development (oil and gas drilling and well servicing)
083	Hydraulic Fracturing – Subsurface Integrity *(May 21, 2013)*	Requirements for managing subsurface integrity associated with hydraulic fracturing. Includes the subject well, offset wellbores, aquifers, water wells and surface impacts. Hydraulic fracturing is a prominent issue in upstream oil and gas operations, especially for the unconventional resources such as tight gas and Shale oil (Duvernay) Includes industry notification requirements for hydraulic fracturing activities and the need for immediate notice of a 'communication event' where pressure or fluid from a hydraulic fracture is observed at an offset well, a non-saline aquifer on water well This directive replaced directive 027 – Shallow fracturing operations – restricted operations

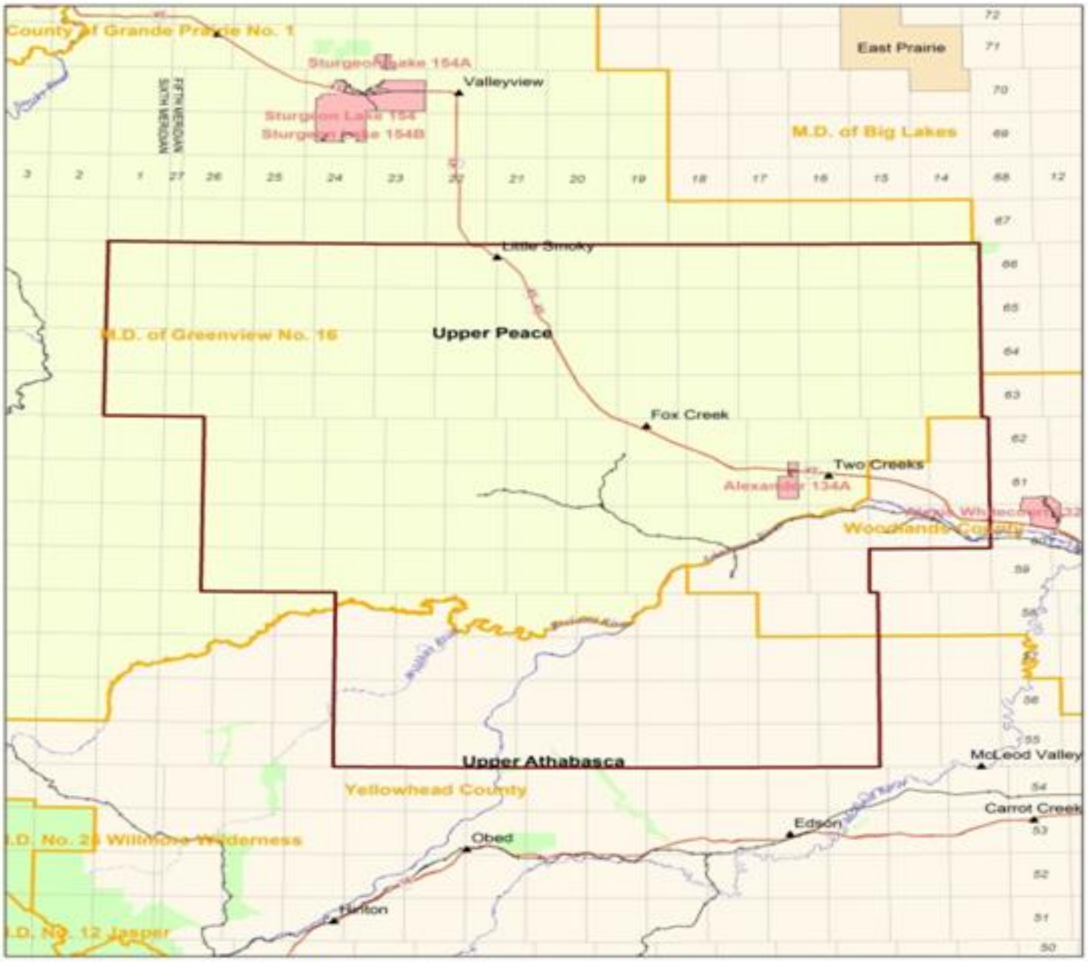
Source: www.aer.ca/rules-and-regulations/directives

Appendix B: Play Based Regulation (PBR) timelines

Date	Pilot activity
April 1, 2014 – Aug 31, 2014	Pilot design: AER develops requirements and processes
September 1, 2014 – March 31, 2015	Pilot implementation: Operators submit single applications to the AER. Applications will not be accepted after March 31, 2015
June 30, 2015	End of pilot
Post-June 30, 2015	The AER makes process adjustments and takes any other essential steps towards broader implementation of PBR

Source: Play –Based Regulation Pilot – Application Guide

Appendix C: PBR Pilot Area (Fox Creek)



Source: Play-Based Regulation Pilot – Application Guide

Appendix D: Hydraulic fracturing fluid product component information disclosure

Component Type	Trade Name	Supplier	Purpose	Ingredient/Family Name	CAS # / HMIRC #	Concentration in Component (% by mass)	Concentration in HFF (% by mass)
CARRIER FLUID				Nitrogen	7727-37-9	100.000000%	4.881396%
CARRIER FLUID				Water	Not Available	100.000000%	64.661288%
PROPPANT	30/50	Sanjel		Crystalline Silica	14808-60-7	100.000000%	27.488057%
ADDITIVE	CG-1BL	Sanjel	Breaker	Petroleum distillates, straight-run middle	64741-44-2	70.000000%	0.144505%
ADDITIVE	CG-1BL	Sanjel	Breaker	Magnesium oxide	1309-48-4	35.000000%	0.072252%
ADDITIVE	BUFFER-A	Sanjel	Buffer	Acetic Acid	64-19-7	60.000000%	0.135036%
ADDITIVE	BUFFER-A	Sanjel	Buffer	Water	Not Available	50.000000%	0.112530%
ADDITIVE	CG-5	Sanjel	Surfactant	Amines, C14-18; C16-18-Unsat, Alkyl, Ethoxylated	68155-39-5	30.000000%	0.761328%
ADDITIVE	CG-5	Sanjel	Surfactant	Ethanol, 2, 2'-(Octadecylamino) bis-	10213-78-2	30.000000%	0.761328%
ADDITIVE	CG-5	Sanjel	Surfactant	Isopropanol	67-63-0	30.000000%	0.761328%
ADDITIVE	CG-5	Sanjel	Surfactant	Hydrochloric Acid	7647-01-0	5.000000%	0.126888%
ADDITIVE	CG-5	Sanjel	Surfactant	Sodium xylenesulfonate	1300-72-7	5.000000%	0.126888%

Source: www.fracfocus.ca