Shale Gas in Canada

Background document

for the

Pembina Institute Thought Leader Forum

Towards Responsible Shale Gas Development in Canada: Opportunities & Challenges

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1. Introduction

1.1 Overview

Over the last half-decade, advances in multi-stage directional drilling and hydraulic fracturing have unlocked vast reserves of unconventional natural gas resources, beginning in the northeastern and southern United States. Because it is home to major shale gas reserves, with a well-established oil and gas business and associated infrastructure, Canada is next on the list to face the economic, environmental and social consequences and opportunities.

According to the International Energy Agency, "Producing unconventional gas is an intensive industrial process, generally imposing a larger environmental footprint than conventional gas development. More wells are often needed and techniques such as hydraulic fracturing are usually required to boost the flow of gas from the well. The scale of development can have major implications for local communities, land use and water resources. Serious hazards, including the potential for air pollution and for contamination of surface and groundwater, must be successfully addressed. Greenhouse-gas emissions must be minimised both at the point of production and throughout the entire natural gas supply chain. Improperly addressed, these concerns threaten to curb, if not halt, the development of unconventional resources. The technologies and know-how exist for unconventional gas to be produced in a way that satisfactorily meets these challenges, but a continuous drive from governments and industry to improve performance is required if public confidence is to be maintained or earned."[1]

Decision-makers in government, communities and industry are thus charged with determining if and how the resources are to be developed, establishing science-based limits, and earning social license from host communities and broader stakeholders.

In the U.S., where development is more established, there has been considerable public focus on the economic benefits, as well as controversy regarding effects on the environment and human health. In response, a number of academic institutions, regulators and expert commissions have attempted to map the issues and define appropriate technology and policy focus areas and approaches for the U.S. context.[2] Some jurisdictions (e.g., New York state) have imposed temporary moratoriums on development while these reviews are underway,

Proponents of shale gas tout the lower combustion carbon footprint of gas compared to coal or fuel oil; the versatility of gas for use in electrical generation, transportation and heating; and its safety of transport compared to oil. Critics raise concerns regarding the environmental impacts

[1] International Energy Agency, *Golden Rules for a Golden Age of Gas*, World Energy Outlook: Special Report on Unconventional Gas (2012). http://www.iea.org/newsroomandevents/pressreleases/2012/may/name,27266,en.html

[2] This includes the Environmental Protection Agency's *Study of Hydraulic Fracturing and Its Potential Impact on Drinking Water Resources*; The MIT Energy Initiative's *Future of Natural Gas* study; the U.S. Department of Energy's *Modern Shale Gas: A Primer* ; The National Petroleum Council's *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*; the Resources for the Future "Managing the Risks of Shale Gas" forum; and the New York State Commission *Environmental Review Process for Natural Gas Exploration in the Marcellus Shale*.

from shale gas development, including on water resources, on habitat and on overall greenhouse gas emissions.

1.2 Why is a Canadian dialogue on shale gas needed?

Canadian provinces and territories are at various stages of dialogue and preparedness to address environmental and social aspects associated with shale gas development. Development of shale gas resources in Canada is at an earlier stage but has been accelerating rapidly, in spite of the low natural gas price environment. Shale gas deposits are found across the country, with the most significant in northeastern B.C., Alberta, and Quebec. Smaller deposits are also found in New Brunswick, southern Ontario and the southern edges of Yukon and Northwest Territories. As in the U.S., there is controversy in some regions, and significant public efforts are underway to scope the issues and define mitigation plans.[3]

In many communities, industry is challenged to earn its social license to operate, placing resource access at risk and generating uncertainty for invested capital. The record in the U.S. suggests that the speed of shale gas development can outpace efforts to develop appropriate infrastructure, regulatory frameworks and operating standards, particularly where oil and gas development is new. In the U.S., the debate has become increasingly partisan, making it difficult to discuss the benefits and disadvantages of shale gas. Canadian stakeholders recognize that they have only a brief window of opportunity to anticipate and plan for shale gas development, and to ensure that the Canadian approach meets the challenges it faces.

Across the board, industry, government, communities and other stakeholders need credible knowledge upon which to shape policy and practice associated with shale gas development in their regions.

In light of this need, the Pembina Institute is convening the Shale Gas Thought Leader Forum in September 2012 to bring together experts from all stakeholder groups in a high-level and non-partisan strategic review of shale gas development in Canada, including the opportunities it presents and the issues it poses. This report provides background to relevant issues and information to inform discussion at the Thought Leader Forum.

Goals of the Forum include:

a. Convening a representative cross-section of key stakeholders and decision-makers in shale gas development from across Canada
b. Establishing a base level of knowledge of environmental concerns across this group
c. Providing a forum for airing sources of frustration and for moving past this into shared understanding
d. Developing a consensus list of potential opportunities for collaboration — specific and achievable actions that can increase shared understanding, clarify uncertainty and resolve controversy

Goals of this background report include:

[3] This includes the Quebec Commission on Shale Gas, the Council of Canadian Academies' review of the state of knowledge of shale gas development and the New Brunswick Natural Gas Development Action Plan Framework.

- Providing an overview of the technology and economic context for shale gas development in Canada
- Summarizing the priority environmental issues raised as concerns by stakeholders, to establish a base level of common knowledge among forum participants
- Providing an overview of industry's current approach to development and the management of the priority environmental issues

1.3 Scope and definitions

This report is focused on Canada and Canadian stakeholders. It is, however, impossible to separate the Canadian natural gas situation from the U.S., in that markets are closely interlinked, shale resources cross borders, and lessons from U.S. experiences are relevant in Canada. Thus, this report frequently references U.S. publications and events while attempting to display them in a Canadian context.

While there is potential for shale gas development in a number of jurisdictions, this report focuses on shale gas production and regulation in B.C., Alberta, Saskatchewan, Ontario, Quebec and New Brunswick.

It should be noted that in this report, "hydraulic fracturing" refers to the injection of fluid and sands at depth to fracture rock. In some media and public documents, "hydraulic fracturing" (or fracking) has been applied more broadly to refer to the whole process of shale gas development, and this may create confusion when discussing impacts of each phase of development.

In Canada, the standard unit of natural gas volume measurement and consumer billing is the cubic metre. However natural gas resources, production, and demand volumes are commonly measured in million cubic feet (MMcf), trillion cubic feet (Tcf) or billion cubic feet (Bcf).

The following terms and acronyms are used in this report.

Acronym or term	Definition
Tcf	Trillion cubic feet
Bcf	Billion cubic feet
MMcf	Million cubic feet
Mcf	Thousand cubic feet
LNG	Liquefied natural gas
GHG	Greenhouse gases

1.4 About the Pembina Institute

The Pembina Institute is a national non-profit think tank that advances sustainable energy solutions through research, education, consulting and advocacy. It promotes environmental, social and economic sustainability in the public interest by developing practical solutions for communities, individuals, governments and businesses. The Pembina Institute provides policy research leadership and education on climate change, energy issues, green economics, energy efficiency and conservation, renewable energy, and environmental governance.

Promoting the resolution of complex public policy questions through collaborative dialogue and joint fact-finding is one of the key roles that the Pembina Institute plays, in partnership with leading universities, think tanks, companies and government agencies. Through its Thought Leader Forums, Pembina helps decision makers to address current energy issues by convening leading authorities, experts and stakeholders who are already actively engaged in the subject matter, in a "roll up the sleeves" effort to get past talking points and into solutions.

1.5 Guiding Questions

From the perspective of Canadians, both project host communities and developers, the emergence of shale gas offers environmental opportunities and challenges. The purpose of this Thought Leader Forum is to enable informed dialogue and discussion on these environmental challenges. It seeks to air the range of perspectives on whether it is possible to make shale gas development work within science-based environmental limits and while meeting the related concerns of communities and other stakeholders; and if so, under what conditions it can do so. Ideally, it will culminate in a few actionable recommendations in the environmental domain, in terms of how to resolve gaps in science, gaps in practice and technology, gaps in regulation, as well as gaps in trust and mutual awareness.

With these objectives in mind, some key questions to keep in mind as you review the present document:

1. What are the underlying drivers of concern associated with the environmental issues raised? Are stakeholders or proponents concerned about potential gaps in science, gaps in industry practice or technology, gaps in regulation, or gaps in trust, mutual awareness and understanding?
2. Are there specific and achievable actions that can increase shared understanding and/or resolve concern? A list of these might include e.g.
    a. data collection / monitoring efforts to establish baselines and trends;
    b. targeted communications, education and disclosure initiatives;
    c. independent and impartial public fact-finding to resolve controversy;
    d. public scientific research to reduce or resolve uncertainty about particular impacts;
    e. collaborative development of standards, management practices and/or dispute resolution mechanisms;
    f. consensus guidance for regulatory actors;
    g. public-private efforts towards technology development, etc.
3. Are there specific issues that in your opinion are unlikely to be resolvable through any of the measures described above?

About Golden Rules for a Golden Age of Gas

In 2012, the International Energy Agency, a multi-government think tank associated with the OECD, released a set of shale gas "Golden Rules" for policymakers and operators, to apply in order to achieve "a level of environmental performance and public acceptance… , paving the way for the widespread development of unconventional gas resources on a large scale".[4] The report is the outcome of a process of consensus-building between governments, natural gas producers and environmental groups to address social and environmental concerns expressed about fracking and shale gas.

The IEA's report has been criticized for failing to provide sufficient detail for regulators and companies to benchmark against in order to demonstrate best practice,[5] and for downplaying the limited GHG benefit of a switch to natural gas. In the IEA modeling that underpins the report, the carbon reduction from fuel switching away from coal is counteracted by higher electricity demand and reduced investment in renewables. A golden age of gas without widespread deployment of CCS leaves the world on a trajectory consistent with a global carbon concentration of 650ppm and temperature rise of 3.5 degrees Celsius, well above the international 2 degrees Celsius target.[6]

from *Golden Rules for a Golden Age of Gas*

"**Measure, disclose and engage**

- Integrate engagement with local communities, residents and other stakeholders into each phase of a development starting prior to exploration; provide sufficient opportunity for comment on plans, operations and performance; listen to concerns and respond appropriately and promptly.
- Establish baselines for key environmental indicators, such as groundwater quality, prior to commencing activity, with continued monitoring during operations.
- Measure and disclose operational data on water use, on the volumes and characteristics of waste water and on methane and other air emissions, alongside full, mandatory disclosure of fracturing fluid additives and volumes.
- Minimise disruption during operations, taking a broad view of social and environmental responsibilities, and ensure that economic benefits are also felt by local communities.

Watch where you drill

- Choose well sites so as to minimise impacts on the local community, heritage, existing land use, individual livelihoods and ecology.
- Properly survey the geology of the area to make smart decisions about where to drill and where to hydraulically fracture: assess the risk that deep faults or other geological features could generate earthquakes or permit fluids to pass between geological strata.
- Monitor to ensure that hydraulic fractures do not extend beyond the gas-producing formations.

Isolate wells and prevent leaks

- Put in place robust rules on well design, construction, cementing and integrity testing as part of a general performance standard that gas bearing formations must be completely isolated from other strata penetrated by the well, in particular freshwater aquifers.
- Consider appropriate minimum-depth limitations on hydraulic fracturing to underpin public confidence that this operation takes place only well away from the water table.
- Take action to prevent and contain surface spills and leaks from wells, and to ensure that any waste

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[4] International Energy Agency, *Golden Rules for a Golden Age of Gas*, World Energy Outlook: Special Report on Unconventional Gas (2012). http://www.iea.org/newsroomandevents/pressreleases/2012/may/name,27266,en.html

[5] John Kemp, "IEA's golden rules for gas are missed opportunity," *Reuters*, May 29, 2012. http://in.reuters.com/article/2012/05/29/column-kemp-fracking-report-idINL5E8GTA6A20120529

[6] http://www.guardian.co.uk/environment/blog/2012/may/29/shale-gas-fracking-green-carbon#block-2 ; see page 91 of "Golden Rules".

fluids and solids are disposed of properly.

Treat water responsibly

- Reduce freshwater use by improving operational efficiency; reuse or recycle, wherever practicable, to reduce the burden on local water resources.
- Store and dispose of produced and waste water safely.
- Minimise use of chemical additives and promote the development and use of more environmentally benign alternatives.

Eliminate venting, minimise flaring and other emissions

- Target zero venting and minimal flaring of natural gas during well completion and seek to reduce fugitive and vented greenhouse-gas emissions during the entire productive life of a well.
- Minimise air pollution from vehicles, drilling rig engines, pump engines and compressors.

Be ready to think big

- Seek opportunities for realising the economies of scale and co-ordinated development of local infrastructure that can reduce environmental impacts.
- Take into account the cumulative and regional effects of multiple drilling, production and delivery activities on the environment, notably on water use and disposal, land use, air quality, traffic and noise.

Ensure a consistently high level of environmental performance

- Ensure that anticipated levels of unconventional gas output are matched by commensurate resources and political backing for robust regulatory regimes at the appropriate levels, sufficient permitting and compliance staff, and reliable public information.
- Find an appropriate balance in policy-making between prescriptive regulation and performance-based regulation in order to guarantee high operational standards while also promoting innovation and technological improvement.
- Ensure that emergency response plans are robust and match the scale of risk.
- Pursue continuous improvement of regulations and operating practices.
- Recognise the case for independent evaluation and verification of environmental performance."

2. Why is shale gas important as an energy resource for Canada?

2.1 Overview of shale gas development

2.1.1 History of shale gas recovery

“Shale gas” is natural gas — methane and other constituents — contained within shale rock formations. The shales themselves are the source rock for oil and gas, created through the aggregation of layers of small organic matter deposited at the bottom of seas or lakes and then buried and heated over the course of millions of years. In contrast to conventional gas reservoirs, these shale gas reservoirs have very low permeability due to the fine-grained nature of the original sediments (gas does not flow easily out of the rock), fairly low porosities (relatively few spaces for the gas to be stored, generally less than 10% of the total volume), and low recovery rates (because the gas can be trapped in disconnected spaces within the rock or stuck to its surface).[7] Different areas within the shale may contain more or less gas, and may include a mix of liquids in addition to gas. While geologists have long known about the potential resource trapped in the shales, the recent combination of horizontal well drilling and hydraulic fracturing treatments have now made them economic to develop.

[7] International Energy Agency, *Golden Rules for a Golden Age of Gas.*

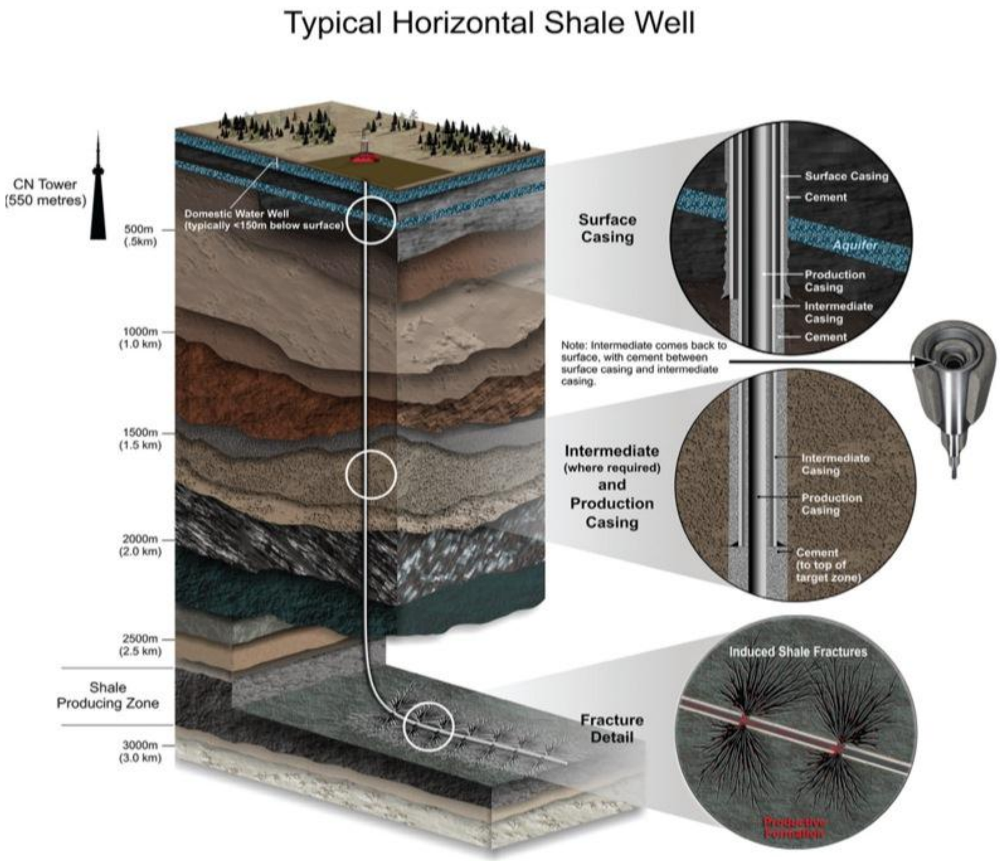


Figure 1: Scaled example of a typical horizontal well for shale recovery

Source: CAPP

Attempts at accessing shale gas resources were made as early as 1821, using vertical wells.[8] During the 1980s, development of improved downhole drilling motors, telemetry equipment, coiled tubing and other technology made horizontal drilling commercially viable.[9] Large-scale hydraulic fracturing — the process of creating fractures to enhance permeability in oil and gas reservoirs — was first tested in the late 1940s in Kansas by Stanolind Oil.[10] The process was commercially deployed through the early 1950s and use has since expanded rapidly.[11] Early fracture treatments used crude oil or kerosene as a fluid, with a gradual switch to refined products. Use of water as a fluid was introduced in 1953 along with gelling agents. Proppants (to

[8] J. Harper, *The Marcellus Shale – An Old "New" Gas Reservoir in Pennsylvania*. v 28, no 1. (Bureau of Topographic and Geologic Survey, Pennsylvania Department of Conservation and Natural Resources, 2008).

[9] Energy Information Administration Office, *Drilling Sideways -- A Review of Horizontal Well Technology and Its Domestic Application* (1993).

[10] Carl T. Montgomery and Michael B. Smith, *Hydraulic fracturing: History of an enduring technology* (2010). http://www.spe.org/jpt/print/archives/2010/12/10Hydraulic.pdf

[11] *Hydraulic fracturing: History of an enduring technology*.

hold the fractures open enabling gas to flow), surfactants, biocides and other additives were gradually developed to improve performance.[12]

In the last five years, technology associated with shale gas development has rapidly improved, and is likely to continue to improve. For example, Baker Hughes, an oilfield services company, has gone from doing a maximum of eight fracturing stages per well in 2005 to a maximum of 40 fracturing stages per well in 2011.[13] Data from Southwestern Energy in the Fayetteville shale in Arkansas presented in Figure 1 show the rapid improvement in drilling and recovery performance over the past five years. In spite of improvements, horizontal wells with hydraulic fracturing are significantly more expensive than conventional natural gas production due to the significant additional equipment and fracture fluids etc. needed, along with the additional manpower.[14]

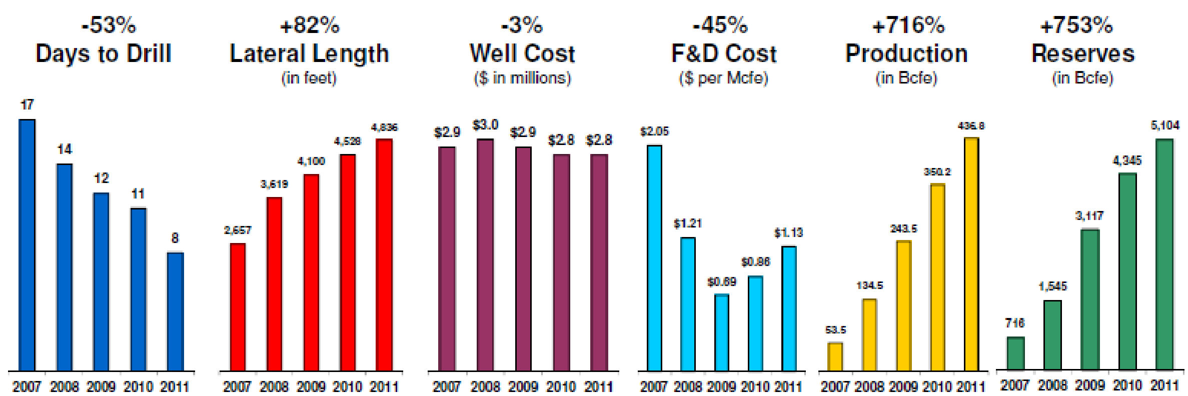


Figure 2: Well statistics from Southwestern Energy's Fayetteville Shale operations, 2007-2011

Source: Southwestern Energy[15]

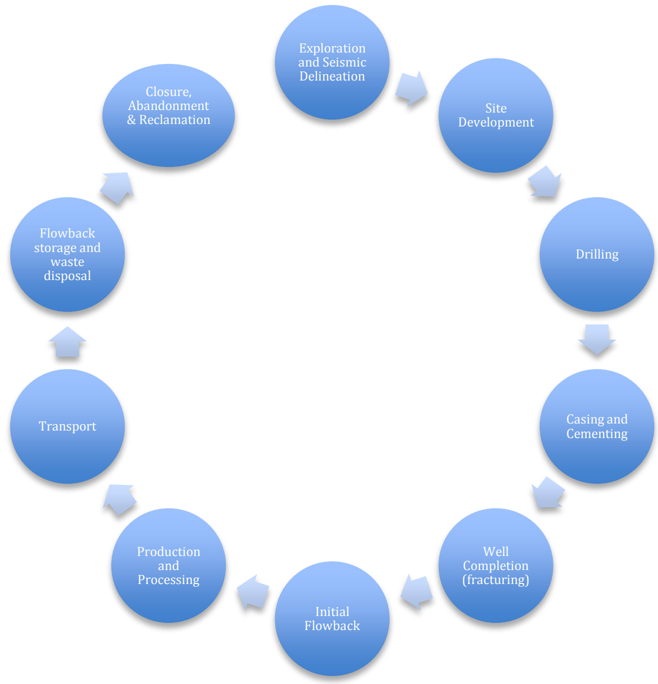
2.1.2 Overview of the shale gas project life cycle and recovery process

[12] *Hydraulic fracturing History of an enduring technology*.

[13] D. Mathieson, "North America Gas: The technology transformation," presentation to CERAWeek 2012, March 5-9, 2012, Houston, Texas.

[14] National Energy Board, *A Primer for Understanding Canadian Shale Gas* (2009).

[15] Southwestern Energy, "The Shale Gale at Age Five," presentation to CERAWeek 2012, March 5-9, 2012, Houston, Texas.



1. **Exploration and seismic delineation** – Exploration and seismic sensing are performed to delineate the resources within the shale gas resources and to inform well design to maximize recovery. These surveys are carried out roughly in a grid pattern, by striking the ground forcefully (with a truck-mounted "thumper"), by vibration or by using buried explosive charges. The sound waves bounce off the various geological layers and return to the surface at different times. Analysis of this data gives an estimation of thickness, density and distribution of geological formations. Seismic surveys generally also require some land clearing to enable the above-ground work to take place.[16]
2. **Site development and drilling preparation** – According to the IEA, a well site, including the drilling rig, associated equipment and pits to store drilling fluids and waste, typically occupies an area of 100 metres by 100 metres. Additional land is cleared for roads and pipelines. Drilling equipment, cement, sand and water for hydraulic fracturing, chemicals, waste fluids for disposal, and other required equipment are brought into the site by truck. Temporary aboveground pipelines may be constructed to convey water from nearby sources (surface or groundwater) to well pads, where available. Other pipelines are needed to transport fluid for reuse or disposal. If water pipelines are not an option due to location, water and fluid are transported by truck. Once on the site, water is generally stored in closed tanks, lined pits, or open-top engineered temporary storage.[17]
3. **Drilling** – In this phase, a drilling rig is sited at the well pad and drills down vertically to an appropriate depth before turning horizontally to follow the shale, creating a lateral leg. Multiple wells can be drilled from a single pad, reducing overall footprint. Drilling can require a few days to many months depending on the geology, depth of the well and

[16] Canadian Association of Petroleum Producers, *Geophysical Exploration Practices* (2007). www.capp.ca/raw.asp?x=1&dt=NTV&e=PDF&dn=81307

[17] S. Olmstead, "Managing the Risks of Shale Gas: Identifying a Pathway toward Responsible Development," presented at Resources for the Future: Managing the Risks of Shale Gas Conference, November 14, 2011.

lateral drilling distance, and will generally be a 24-hour-per-day operation due to the expense of the drilling rig. Drilling fluid, composed of water, salts, oils and particles, is pumped down the hole to lubricate the drill bit. Large volumes of waste rock material (called drill cuttings) — as much as 100 to 500 tonnes per well, depending on the overall wellbore length[18] — drilling mud and other waste must be disposed of.

4. **Casing and cementing** – A metal sheath (called casing) and cement to hold the casing in place are installed in the wellbore, as barriers to ensure that high-pressure gas or liquids cannot escape from the wellbore into groundwater areas or shallower rock.
5. **Well completion (Fracturing) –** The area that is to be fractured is isolated from the rest of the well with sleeves or balls. Small explosive charges are detonated in the wellbore to perforate the casing at spaced intervals. Hydraulic fracturing fluid containing proppant (sand or ceramic beads) is pumped under pressure to crack the rock out to several hundred feet from the wellbore. Though generally just millimeters wide, cracks can extend up to hundreds of meters from the well bore.[19] The proppant beads are wedged in the cracks, creating pathways for the gas to flow into the wellbore for production. Fracturing is generally commenced at the farthest extent, or toe, of the well, and moves in stages closer the vertical portion of the well. A wellbore that extends 1.5 km horizontally within a shale layer might be hydraulically fractured 10 to 15 times at intervals approximately 100 meters apart.[20] Each perforation interval is isolated in sequence so that only a single section of the well is hydraulically fractured at a given time.[21]
6. **Initial flowback** – Once hydraulic fracturing has been completed, some of the fluid injected flows back up the well, although 20–85% remains in the formation. In shale gas wells, the volume of flowback fluid is very high in the first few days after well completion, and the rate rapidly drops off as pressure falls. The proportion of gas in the flowback increases until the flow is primarily hydrocarbons. There are three options for managing the hydrocarbons that are produced during the flowback period: venting, flaring, or capture.
7. **Production and processing** – Following the initial flowback, the natural gas and other hydrocarbons that flow up the well are transferred to a processing facility that removes natural gas liquids, carbon dioxide and other compounds. Unconventional gas wells tend to produce high volumes in the first few years of production, followed by a 50–75% decline. Most of the recoverable gas is extracted during the initial period.[22]
8. **Transport** – Gas then enters the pipeline system for distribution. Compressor station facilities are used to maintain pressure to move the gas through the transmission system.
9. Alternatively, gas can be **converted to LNG** at some facilities and then can be shipped by tanker or truck to its destination. Natural gas can also be injected and stored in underground formations, or liquefied and stored in tanks, during periods of low demand.

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[18] International Energy Agency, *Golden Rules for a Golden Age of Gas.*

[19] R.S. Davies, A. Mathias, J. Moss, S. Hustoft, L. Newport, "Hydraulic fractures: How far can they go?" *Marine and Petroleum Geology* 37, no.1 (2012). http://dx.doi.org/10.1016/j.marpetgeo.2012.04.001

[20] M. Zoback, S. Kiasei, B. Copithorne, *Addressing the Environmental Risks from Shale Gas Development.* (Worldwatch Institute, 2010).

[21] *Addressing the Environmental Risks from Shale Gas Development.*

[22] International Energy Agency, World Energy Outlook 2009.

10. **Flowback fluid storage and waste disposal** – Fluids and other oilfield wastes may in theory be either treated and released, or disposed of through injecting in deep disposal wells. Across Canada, the handling of oilfield waste is closely regulated, with injection in disposal wells as the standard. In the U.S., there has been controversy associated with the shipping of these wastes to municipal wastewater plants for treatment.
11. **Closure, abandonment and reclamation –** After a well stops producing gas at an economic rate, it may be closed and temporarily made inactive until such time as price or recovery techniques permit reactivation; or, a well may be permanently decommissioned. Wells that are left inactive for many years pose a risk of contamination: the producer may potentially become insolvent and thus fail to fully abandon and remediate the well site (so-called "orphan" wells). For that reason, many jurisdictions create regulatory drivers to deal with the accumulation of inactive wells.[23]

    Surface abandonment involves removal of aboveground production equipment. Downhole abandonment involves removal of downhole equipment, and plugging of the well with cement to ensure permanent prevention of flows between hydrocarbon-bearing and water-bearing zones. Reclamation (often used interchangeably with remediation) may be undertaken to return the disturbed area to a pre-project state, though precise standards vary from jurisdiction to jurisdiction.

2.1.3 Shale gas resources in Canada

With the recent development of shale gas resources and recovery technologies, estimates (although uncertain) point to the technically-recoverable presence of a world-class resource of 388 Tcf of shale gas in Canada. This is roughly half the size of the resource that is estimated be present in the U.S. (862 Tcf). Canada is believed to have approximately 501 Tcf of technically-recoverable conventional natural gas resources (including what has already been produced); adding the technically-recoverable shale gas would almost double this amount (see table below).[24] This resource represents roughly 100 years of natural gas use in Canada (usewas 2.9 Tcf in 2010).[25]

As the technology continues to improve, the gap between what is estimated to be 'in-place' versus what is technically recoverable will likely shrink, even as discovery of additional resources will likely continue. Limiting factors on the portion of the shale gas resource that will ultimately be produced include the price that the market is willing to pay for the resource, the availability and cost of transport infrastructure to bring the gas to markets, the presence of greenhouse gas limits, and the willingness of communities and regions to host development of the resource.

[23] L. Muehlenbachs, "Idle Oil Wells: Half Empty or Half Full?" presented at the 32nd IAEE International Conference, San Francisco, 2009. www.iaee.org/en/students/best_papers/muehlenbachs.pdf

[24] National Energy Board, *Canada's Conventional Natural Gas Resources* (2004). http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/cndscnvntnlntrlgsrsrc/cndscnvntnlntrlgsrsrc-eng.pdf

[25] CIA World Factbook. Canada: Natural Gas consumption. This value is estimated from the difference between the volume of natural gas exported and the volume of natural gas produced.

Table 1: U.S. EIA Estimate of the Scale of Shale Gas Resources in Canada, 2011[26]

Name	Location, size	Estimated shale gas in-place (Tcf)	Technically-recoverable shale gas (current technology) (Tcf)
Horn River (Muskwa/Otter Park and Evie/Klua)	Northern British Columbia and the Northwest Territories 21,000 km^2	378 (Muskwa/Otter Park) 110 (Evie/Klua)	132 (Muskwa/Otter Park) 33 (Evie/Klua)
Cordova	Extreme northeastern corner of British Columbia 11,000 km^2	83	29
Liard	Northern British Columbia 11,000 km^2	125	31
Deep basin (Montney and Doig Phosphate)	Straddles the border of Alberta and British Columbia 6800 km^2	141 (Montney) 81 (Doig Phosphate)	49 (Montney) 20 (Doig Phosphate)
Colorado Group	Southern Alberta and southeastern Saskatchewan 321000 km^2	408	61
Appalachian Fold (Utica)	St. Lawrence Lowlands of Quebec 9000 km^2	155	31
Windsor (Horton Bluff)	North-central Nova Scotia 1700 km^2	9	2
Canada (total)		**1,490**	**388**

As seen above, more than 50% of Canada’s technically-recoverable resources are found in the Horn and Montney formations of northeastern B.C. These areas have been the focus of industry activity so far.

2.2 Potential economic implications for Canada

Natural gas is and will continue to be an important energy source for Canada, as well as a major export product. Today, Canada is the third largest producer and exporter of natural gas in the world.[27] Estimates of total revenues from Canadian natural gas exports in 2010 were $15 billion, down from $33 billion in 2008 prior to the global financial downturn.[28]

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[26] Advanced Resources International, *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*, prepared for the U.S. Energy Information Administration (2011). http://www.eia.gov/analysis/studies/worldshalegas/

[27] U.S. Energy Information Administration, *International Energy Statistics*

[28] National Energy Board, *2010 Natural Gas Exports and Imports Summary*. http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/sttstc/ntrlgsxprt/ntrlgssmmr/2010/smmry2010-eng.html

Natural gas prices in North America have dropped markedly from highs over the past few years, due to a decrease in demand caused by the global economic situation, and the increase in available supply in the U.S. brought about by the shale gas boom there. Figure 3 shows the price volatility in the main gas hub in Canada (the Alberta spot price (AECO)). There has been a sustained drop in the price of natural gas, with implications for the national and global energy mix. Depending on the distance of the production from market and the costs associated with processing the gas to appropriate specifications, the price of gas may well be below the cost of production.[29]

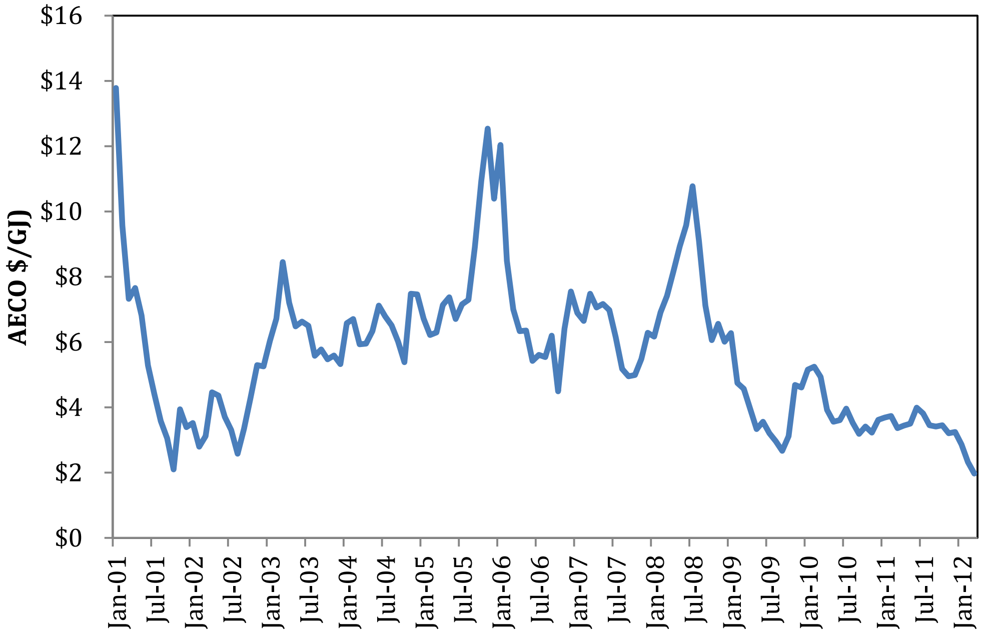

Figure 3: Decline in price of natural gas January 2001 to January 2012

Source: National Energy Board

[29] Ziff Energy. *Natural Gas Under Siege: A Ziff Energy White Paper* (2012). http://www.ziffenergy.com/download/papers/natural_gas_under_siege_white_paper.pdf

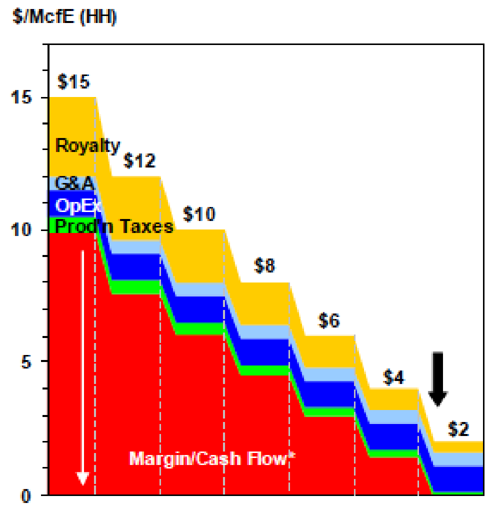

Figure 4: Estimated profit margin/cash flow from sale of natural gas vs. gas market price
Note that at $2/Mcf price, profit margin drops to zero

Source: Ziff Energy[30]

The increase in available gas has spurred many discussions about the potential role that shale gas could play in enhancing Canadian competitiveness, public services and economic growth by:

- **Paying royalties to the government** – Currently B.C. and Alberta have very similar royalty regimes for natural gas.[31] B.C. is predicting $398 million in revenue from gas royalties in 2012/2013.[32]
- **Paying revenues from drilling rights to the government and other land holders** – Revenues from land sales for natural gas rights in B.C. peaked at $2.4 billion in 2008, although sales have dropped dramatically since then due to global economic conditions, and are only slowly recovering.[33]
- **Reducing the cost of domestic manufacturing** – The gas could lower the cost of chemical and energy feedstocks, potentially improving the international competitiveness of Canada's manufacturing sector.[34]

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[30] *Natural Gas Under Siege.*

[31] M.Carroll, E. Stephenson, and K. Shaw, "Political Economy and the Challenge of Shale Gas: Negotiating a Post-Staples Trajectory," *Canadian Political Science Review*, 5, no. 2 (2011).

[32] Government of British Columbia, 2012 Budget. Estimates for fiscal year ending March 31, 2013. http://www.bcbudget.gov.bc.ca/2012/estimates/2012_Estimates.pdf

[33] C. Adams, B.C. Ministry of Energy, Mines and Petroleum Resources, *Shale Gas Activity in British Columbia*, presented at 4th Annual Unconventional Gas Technical Forum, Victoria, B.C. April 8, 2010. http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalGas/Documents/C%20Adams.pdf

[34] American Chemistry Council, *Shale Gas and New Petrochemicals Investment: Benefits for the Economy, Jobs, and U.S. Manufacturing* (2011). http://www.americanchemistry.com/ACC-Shale-Report

- **Employment** – It is not clear how many jobs have been directly caused by shale gas development in Canada. In February 2012 the B.C. government predicted that the natural gas industry would open up only 1000–2000 more jobs within the next five years.[35] In the U.S., a study prepared for America's Natural Gas Alliance group estimates that shale gas development has created 148,000 direct jobs[36] plus 452,000 indirect and induced jobs.[37] It is important to note that some shale gas development could occur in several provinces and regions that have not traditionally experienced natural gas development (e.g., Quebec) and/or may be experiencing a decline in other industries (e.g., the manufacturing sector in Ontario).
- **Reducing transportation costs and emissions** – A broadscale shift to natural gas vehicles, particularly in the shipping industry, could provide cost and emissions savings for the transportation industry, but would require significant technological and infrastructure investments.[38]
- **Reduced cost of importing natural gas** – Increased domestic production could help reduce the need for importing natural gas (which was $3.91 billion in 2010).[39] This may require additional pipeline capacity to move gas from western Canada to the main consumer base in eastern Canada.
- **Sale of natural gas liquids** – In the face of low prices of natural gas, many producers are seeking natural gas liquids like propane, butane and ethane that are often co-produced with natural gas, but with higher market prices.[40]

At the same time, there are economic and governance risks from the growth in shale gas production for Canada, including:

- **Increased burden on regulators** – Some stakeholders have raised concern regarding the capacity of regulatory agencies to ensure comprehensive assessment and oversight of project applications and operations in alignment with performance requirements, particularly in jurisdictions new to oil and gas development.[41,42,43]

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[35] BC Natural Gas Strategy, February 2012, p. 8.

[36] IHS Global Insight, *The Economic and Employment Contributions of Shale Gas in the United States*, prepared for America's Natural Gas Alliance (2012). http://www.ihs.com/images/Shale_Gas_Economic_Impact_mar2012.pdf

[37] The IHS study estimated that "for every direct job created in the shale gas sector, more than three jobs are added across indirect and induced contributions." This makes the natural gas industry one of the highest job-producing sectors. The reasons stated for this high level of induced and indirect jobs are that shale gas is capital-intensive (with more than 50% of revenues spent on capital investment, or more than $500,000 per well), and the supply chain is largely domestic in the U.S. It is unclear if this same level of induced and indirect jobs would be stimulated in Canada.

[38] A.J. Krupnick, *Energy, Greenhouse Gas, and Economic Implications of Natural Gas Trucks*, (Resources for the Future, 2010). http://www.rff.org/RFF/Documents/RFF-BCK-Krupnick-NaturalGasTrucks.pdf

[39] National Energy Board, *2010 Natural Gas Exports and Imports Summary*.

[40] David Hughes, "With gas so cheap and well drilling down, why is production so high?" *Energy Bulletin*, January 8, 2012. http://www.energybulletin.net/stories/2012-01-18/gas-so-cheap-and-well-drilling-down-why-gas-production-so-high (accessed Mar. 14, 2012).

[41] ProPublica, "How Big is the Gas Drilling Regulatory Staff in Your State?" http://projects.propublica.org/gas-drilling-regulatory-staffing/

[42] U.S. Government Accountability Office, *Increased Permitting Activity Has Lessened BLM's Ability to Meet Its Environmental Protection Responsibilities*. http://www.gao.gov/assets/250/246744.pdf

- **Strain on community social and economic systems** – Potential impacts include: a shortage of qualified workers, increases in price of goods and materials, wages, increased demand on municipal infrastructure and services, and social problems associated with transient workers with high disposable incomes.[44]
- **Dependence on volatile natural gas prices –** As mentioned above, gas prices have been volatile in recent years, rising dramatically in 2008 and falling in 2012to levels not seen since 1998.[45] The C.D. Howe Institute warns that adjusting to the volatility in revenue carries economic, social and political costs.[46] In Canada, these risks can be seen in fluctuating anticipated revenue in B.C. (where predicted shale gas revenues for 2012/13 dropped 33% from 2011[47] to 2012.[48] Another risk comes from the increasing dependence of some economic sectors on gas prices (e.g. electricity generation in Ontario is becoming increasingly linked to gas prices).
- **Natural resource-related currency appreciation** – The exchange rate for a country's currency can appreciate due to its export of resource wealth, to the point where the country's manufactured goods become more expensive internationally than competing products, weakening the manufacturing sector.[49] Canada may already be experiencing some level of this due to its focus on resource development.[50,51,52] A large boom in shale gas development could contribute to this phenomenon.

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[43] Energy Institute, *Fact-Based Regulation for Environmental Protection in Shale Gas Development* (2012). http://energy.utexas.edu/images/ei_shale_gas_regulation120215.pdf

[44] For example, see the social impacts of oilsands development in Fort McMurray, AB, outlined in: Regional Municipality Of Wood Buffalo, *Submission To The Alberta Royalty Review Panel* (2007). http://www.albertaroyaltyreview.ca/public_meetings/submissions/2007_0605_melissa_blake_rm_wood_buffalo01.pdf

[45] On March 13th, the AECO spot price dropped to $1.62/BTU. See historical price trends at http://www.ngx.com/

[46] Stuart Landon and Constance Smith. *Energy Prices and Alberta Government Revenue Volatility*, Commentary No. 313 (C.D. Howe Institute, 2010).

[47] Government of British Columbia, "B.C. Government Budget and Fiscal Plan, 2011/2012 – 2013/2014," February 15, 2011, charts 1.5 and 1.7. http://www.bcbudget.gov.bc.ca/2011/bfp/2011_Budget_Fiscal_Plan.pdf

[48] Government of British Columbia, 2012 Budget. Estates for fiscal year ending March 31, 2013. http://www.bcbudget.gov.bc.ca/2012/estimates/2012_Estimates.pdf

[49] The term Dutch disease was coined by *The Economist* to describe a phenomenon that occurred in the 1970s in the Netherlands, when the country discovered and began to aggressively develop offshore natural gas.

[50] OECD, *OECD Economic Surveys: Canada 2010*. Vol. 14. (2010). http://www.oecd-ilibrary.org/economics/oecd-economic-surveys-chile-2010_eco_surveys-chl-2010-en

[51] B. Michel, C.S. Bos, and S. Coulombe, "Does the Canadian Economy suffer from the Dutch Disease?" *Resource and Energy Economics*, 34, no. 4 (2012).

[52] M. Beine, S. Coulombe, and W. Vermeulen, *Dutch Disease and the Mitigation Effect of Migration: Evidence from Canadian Provinces* (2012). http://www.michelbeine.be/pdf/Beine,%20Coulombe,%20Vermeulen%202011.pdf

- **Risk of liability/ stranded assets–** If significant public concerns or severe unforeseen environmental impacts of natural gas lead to moratoriums or limits on the development in the future after an initial amount has been invested in land sales or infrastructure, there is a risk to investors from the 'stranding' of assets. In Quebec, for example, producers are uncertain regarding the fate of their investments, as the government carries out a strategic environmental assessment expected to take between two and three years.[53]

2.3 Potential environmental benefits for Canada

Natural gas has been touted as "green" and "bridge to a low-carbon future" for several reasons:[54]

- **Reduction of greenhouse gas (GHG) emissions from power production:** Because of the lower carbon content of natural gas, replacing coal with natural gas to produce power is thought to be a significant step toward reducing GHGs and air emissions.
- **Reduced water use compared to other energy sources:** One high-level review has found that water use associated with production of one unit of energy from shale gas (36-54 litres/GJ) is comparable to coal, comparable or up to one-tenth that of oil sands and could be one-ten-thousandth that of biofuels.[55] Water use for shale development varies considerably from region to region, as does relative scarcity of the associated water for other needs, including ecosystem integrity, industry and agriculture.
- **Reduced air and GHG emissions from transportation:** The conversion of significant portions of the transportation fleet could substantially reduce GHG emissions in this sector. In the U.S., use of domestically-produced natural gas in place of gasoline or diesel for transportation could result in ~10-30% GHG reductions on a well-to-wheels basis.[56]

2.4 Potential trade implications for Canada

The abundance of natural gas in Canada and the U.S. is already shifting the established patterns of energy import and export. Predicted changes include:

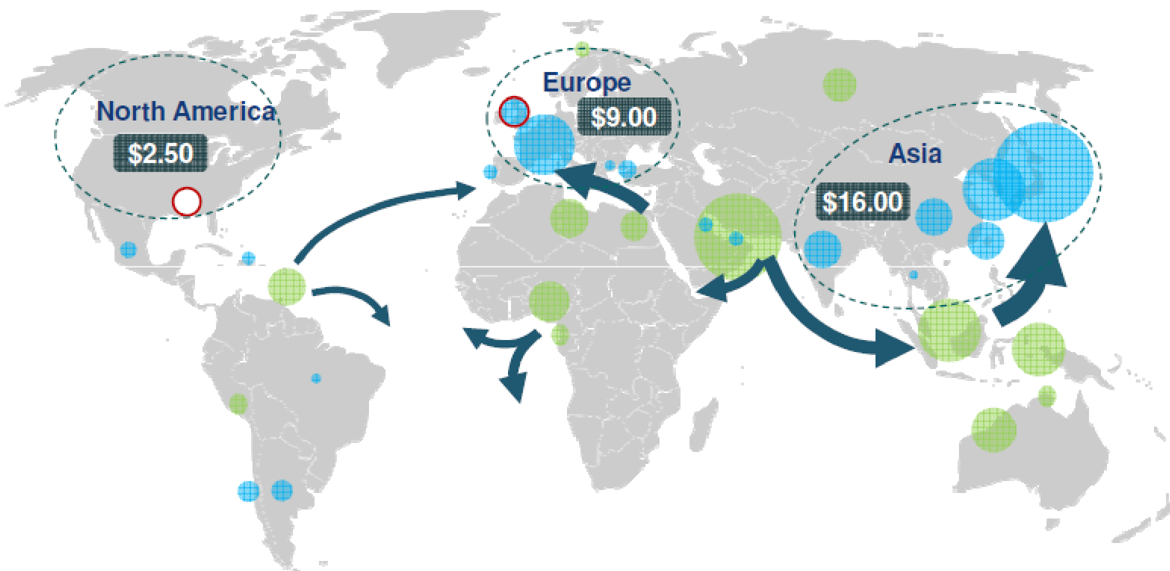
[53] Financial Post, "Quebec moratorium leaves shale gas drillers staggering," available at CBC News, June 30, 2011 http://www.cbc.ca/fp/story/2011/06/30/5031205.html

[54] J. Podesta and T. Wirth, *Natural Gas: A bridge fuel for the 21st century* (Center for American Progress, 2009). http://www.americanprogress.org/issues/green/report/2009/08/10/6513/natural-gas-a-bridge-fuel-for-the-21st-century/

[55] Water use of production of various fuels: Biofuel (based on soy and corn grown in conditions that require irrigation) 9000-270,000 litres/GJ; coal (50-70 litres/GJ); oil sands (70-1800 litres/GJ). From: World Economic Forum, *Thirsty Energy: Water and Energy in the 21st Century* (2008). http://www3.weforum.org/docs/WEF_WaterAndEnergy21stCentury_Report.pdf.

[56] Krupnick, *Energy, Greenhouse Gas, and Economic Implications of Natural Gas Trucks,* Table 4.

- **Reduced Canadian export to the U.S.** – Growing production in the U.S. is exceeding growth in natural gas demand. The U.S. is increasingly able to meet its demand internally, reducing its dependence on Canada for import, as well as allowing it to look externally for markets where gas can be sold. This is a drastic and rapid change from the current situation, where Canada supplies the United States with substantial natural gas supplies (3.2 trillion cubic feet in 2009[57]). The IEA predicts that net export could drop by 62% by 2035, due to declining U.S. market share.[58]
- **Export of LNG to Asia** – Throughout the 1990s, the Canadian and U.S. governments were planning import terminals to bring gas to fill the anticipated gap in supply in the North American market.[59] Currently, the availability of natural gas in North America means that both countries are looking to export natural gas in the form of LNG. The most recent predictions by the U.S. Energy Information Administration projects that the U.S. will become a net exporter of LNG in 2016, an overall net exporter of natural gas in 2021 and a net pipeline exporter by 2025.[60] In Canada, the National Energy Board projects that gas exports will decline in the short term, because of increasing internal demand, but will rebound after 2020 as production increases.[61] Both countries are looking to expand their market reach to Asia and Europe, where pricing is substantially more favourable — though conversion and transportation costs will be significant (see Figure 5).



[57] U.S. Energy Information Administration, *2011 Annual Energy Outlook*. http://www.eia.gov/forecasts/archive/aeo11/pdf/0383(2011).pdf

[58] International Energy Agency, *Golden Rules for a Golden Age of Gas*.

[59] In the U.S., former Federal Reserve chief Alan Greenspan argued the need for liquefied natural gas import terminals into the U.S. as recently as 2005. In Canada, the LNG export terminal in Kitimat, B.C. was originally proposed as an import terminal, and was changed due to shifting supply and market conditions.

[60] U.S. Energy Information Administration, *2012 Annual Energy Outlook: Early release overview* 1 (2012) http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf

[61] National Energy Board, *Canada's Energy Future: Energy Supply and Demand Projections to 2035* (2011). http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2011/nrgsppldmndprjctn2035-eng.html

Figure 5: Global pricing and trade patterns for LNG

Source: Centrica plc[62]

Some 11 LNG export terminals are proposed or in various phases of development for the west coast of British Columbia. Premier Christy Clark has indicated that completion of three terminals by 2020 is an explicit goal of her government.[63]

Canadian LNG exports would face many hurdles, including capital cost, labour and component bottlenecks, social license, and competition from other supply countries.[64] For example, the Kitimat LNG conversion terminal project and associated pipeline infrastructure is estimated to cost $3 billion.[65] The U.S. is predicted to become a net exporter of LNG starting in 2016,[66] and other sources of gas for Asian markets include China,[67] Australia and Russia.[68]

2.4.1 Controversy over shale gas development

In general, there is variation in public reaction to shale gas development between regions, depending on the level of development, the proximity of this development to towns and homes, and the history of oil and gas exploration in that area.[69] Local residents who are unaccustomed to industry presence and the process of surface access may have greater concerns about surface disturbance. There has been less concern about shale gas development in Alberta, where there is extensive conventional oil and gas development, as compared to southern Ontario or Quebec where there has been very little energy development historically.[70] Following is a short summary of issues in some Canadian provinces that have garnered media and public attention and concern:

- **B.C.** – Northeastern B.C. is the most established shale gas area in Canada. The industry is rapidly changing the socio-economic conditions of the region.[71] Some concerns about the impacts of development have been expressed.[72,73,74] It is alleged that a series of six

[62] Centria plc, "A Growing Role for Natural Gas: A European Utility Perspective," presentation to CERAWeek 2012, March 5-9, 2012, Houston, Texas.

[63] B.C. Ministry of Energy and Mines, *Liquefied Natural Gas: A Strategy for B.C.'s Newest Industry* (2012). http://www.gov.bc.ca/ener/popt/down/liquefied_natural_gas_strategy.pdf

[64] D. Yergin et al., *Fueling North America's Energy Future: The Unconventional Natural Gas Revolution and the Carbon Agenda* (IHS Cambridge Energy Research Associates, 2009), IV-7.

[65] Apache Corp., *Canadian Natural Gas is Going Global*, presentation to the National Energy Board, May 6, 2009. http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/cnslttnrnd4/prsnttn/alfred_sorenson.pdf

[66] U.S. Energy Information Administration, *Annual Energy Outlook 2012*.

[67] K. Medlock and P. Hartley, *Quantitative analysis of scenarios for Chinese domestic unconventional natural gas resource and their role in global LNG markets* (James A Baker III Institute for Public Policy, 2011).

[68] Alberta Oil, "Chinese shale gas could undermine LNG market," March 14, 2012. http://www.albertaoilmagazine.com/2012/03/chinese-shale-gas-could-undermine-lng-market/

[69] Energy Resources Conservation Board, *Unconventional Gas Regulatory Framework—Jurisdictional Review,* Report 2011-A (2011). http://*www.ercb.ca/reports/r2011-A.pdf*

[70] B. Parfitt, *Fracture Lines: Will Canada's water be protected in the rush to develop shale gas?* (Munk Centre for Global Affairs, 2010).

[71] CBC News, "B.C.'s shale gas boom," September 26, 2011. http://www.cbc.ca/news/canada/british-columbia/story/2011/09/26/bc-feature-shale-gas-boom.html

[72] Canadian Centre for Policy Alternatives, *Fracturing up B.C.*, video. http://www.policyalternatives.ca/multimedia/fracking-bc

pipeline bombings of Encana facilities near Dawson Creek were motivated in part by concern over water use in natural gas development.[75] There are also concerns about water withdrawals around Dawson Creek, a region that historically has experienced periods of very low water levels,[76] and where the oil and gas industry is purchasing an increasing percentage of the municipal drinking water supply.[77] At the political level, the government has been mostly supportive of shale gas development, but two Independent MLAs in B.C. have called for the establishment of a special legislative committee to look at shale gas issues around Dawson Creek.[78]

- **Alberta** – There has been some media attention and public concern regarding shale gas activity in Alberta. It has been reported that the ERCB is investigating five well-blowout incidents related to hydraulic fracturing (though it is not clear if these incidents were all in shale gas wells).[79] The Alberta Surface Rights Group is calling for a moratorium on hydraulic fracturing.[80]
- **New Brunswick** – Shale gas been controversial in New Brunswick,[81] and a recent poll shows that the population is evenly divided between support and disapproval of shale gas development.[82] The opposition Liberal party has called for a moratorium on hydraulic fracturing until better regulatory oversight is in place.[83]

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[73] Globe and Mail, "B.C. First Nation challenges oil and gas tenures sale," June 26, 2011. http://www.theglobeandmail.com/news/british-columbia/bc-first-nation-challenges-oil-and-gas-tenures-sale/article584552/

[74] BC Tap Water Alliance, "Stop Fracturing in British Columbia." http://www.bctwa.org/Fracking-BCInformation.html

[75] CBC News, "B.C. pipeline bombings 3 years old with no charges laid," Oct 12, 2011. http://www.cbc.ca/news/canada/calgary/story/2011/10/11/bc-encana-bombings-anniversary.html

[76] Forest Practices Board, *A case study of the Kiskatinaw River watershed*, appendix to *Cumulative Effects: From assessment towards management* (2011). http://www.fpb.gov.bc.ca/SR39_CEA_Case_Study_for_the_Kiskatinaw_River_Watershed.pdf

[77] K. Campbell and M. Horne, *Shale gas in British Columbia: Risks to BC's water resources* (Pembina Institute, 2011).

[78] "Independant MLAs to visit Peace Region for educational purposes," *Bob Simpson*, March 19, 2012. http://www.bobsimpsonmla.ca/independant-mlas-to-visit-peace-region-for-educational-purposes/

[79] A. Nikkiforuk, "Alberta Plays Catch-up on Frack Front," *The Tyee*, February 23, 2012. http://thetyee.ca/News/2012/02/23/AlbertaCatchUp/

[80] Mountain View Gazette, "Group calls for moratorium on fracking," January 1, 2012. http://www.mountainviewgazette.ca/article/20120131/MVG0801/301319994/-1/mvg08/group-calls-for-moratorium-on-fracking

[81] CBC News, "Hundreds protest hydro-fracking in Fredericton," November 19, 2011. http://www.cbc.ca/news/canada/new-brunswick/story/2011/11/19/nb-hydro-fracking-rally.html

[82] 45% of the survey respondents were in favour of shale gas exploration and 45% were in opposition. From: CBC News, "New Brunswick divided over shale gas, poll shows," December 13, 2011. http://www.cbc.ca/news/canada/new-brunswick/story/2011/12/13/nb-cra-shale-gas-poll-1129.html

[83] New Brunswick Liberal Party, "Liberals support call for shale gas moratorium," June 29, 2011. http://nbliberal.ca/1452/liberals-support-call-for-shale-gas-moratorium

- **Ontario –** While Ontario has not been a very high priority region for shale gas development so far,[84]and shale gas resources may be limited,[85,86] one city has gone as far as to ban hydraulic fracturing within municipal limits.[87]
- **Quebec** – There has been considerable public concern in Quebec raised over shale gas exploration, including petitions, protests[88] and formation of citizens' groups.[89] The provincial government halted the issuance of exploration permits in March 2011 until a provincial review of hydraulic fracturing by a panel of eleven experts is complete.[90] In a poll by polling firm Angus Reid, only 22% of Quebec is in favor of fracturing, the lowest proportion in the country.[91]

On the whole, Canadian shale gas production is in its infancy and occurs farther away from major population centres, whereas activity in the U.S. has occurred within dense urban areas. As a result there have been generally fewer conflicts between landowners, municipalities and oil and gas operations in Canada as compared to the U.S at this point in development.[92]

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[84] Toronto Star, "Alberta firm eyes Ontario's untapped shale gas," March 20, 2010. http://www.thestar.com/business/article/782552--alberta-firm-eyes-ontario-s-untapped-shale-gas

[85] Mooncor Oil and Gas homepage http://www.mooncor.com/

[86] Willms and Shier, LLP, *Shale gas. Special issue* (2011). http://www.willmsshier.com/pdf/Willms_&_Shier_Special_Report_Shale_Gas_December_2011.pdf

[87] Niagara Gazette, "Council's anti-hydrofracking vote brings ovation," March 5, 2012 http://niagara-gazette.com/local/x1511867858/Councils-anti-hydrofracking-vote-brings-ovation

[88] Equiterre, "Shale gas protest on June 18 in Montreal," June 13, 2011. http://www.equiterre.org/en/news/shale-gas-protest-on-june-18-in-montreal

[89] Regroupement Interregional sur le Gaz de Schiste de la Vallee du Saint-Laurent. http://regroupementgazdeschiste.com/2/index.html

[90] Globe and Mail, "Quebec halts shale gas exploration," March 8, 2011. http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/quebec-halts-shale-gas-exploration/article1934217/

[91] Financial Post, "Quebec moratorium leaves shale gas drillers staggering."

[92] Parfitt, *Fracture Lines: Will Canada's water be protected in the rush to develop shale gas?*

3. Survey of environmental concerns and state of knowledge

The section that follows provides a survey of the major environmental concerns that have been associated with shale gas development by stakeholders, at both the local and the national level. It seeks to describe the concern and the degree of certainty associated with the science behind the concern, while drawing upon leading references as much as possible. Its objective is to provide participants in the Shale Gas Thought Leader Forum with sufficient background to enable informed discussion.

A number of environmental issues that are associated with shale gas development are also relevant in the context of conventional oil and gas production. These include blowouts, spills, faulty casing and cementing causing gas migration. They are also, however, frequently raised in public dialogue in association with shale gas development, which is the rationale for their inclusion below.

Environmental Concerns associated with Shale Gas Development

Local issues

- Water use
    - Contamination of water from methane
    - Contamination of water from fracturing fluid
- Waste treatment and disposal
- Local air quality
- Land use and biodiversity impacts
- Induced Seismicity

National-scale issues

- Energy Mix
- Greenhouse gas emissions

Cumulative environmental effects

- Surface cumulative effects
- Subsurface cumulative effects

3.1 Local issues

3.1.1 Water use

Shale gas development sources water from surface basins, shallow ground water (which is typically fresh), deep groundwater (which is typically saline) and/or recycled water (either flowback water from the well, which is a combination of the injected water and formation water, or from other sources like municipal wastewater).

Most of the water used in shale development to date in Canada has been fresh surface water or shallow groundwater.[93] In the Horn River in British Columbia, where there are few large rivers or lakes, fracturing fluid has been sourced almost entirely from small lakes (such as Two Island Lake) and groundwater. Recently, operators have applied to remove water from hydro-electric reservoirs in B.C. for use in hydraulic fracturing.[94]

The amount of water needed per well varies depending on the type of shale gas formation. Estimates of water use per well in Canada range from 10,000–20,000 m^3 (equivalent to four to eight Olympic-sized swimming pools) over the lifetime of the well.[95] In the U.S., companies have used between 7,600 and 26,500 m^3 of water per over the lifetime of a well in the Marcellus Shale.[96] Shale gas production requires 2,000–10,000 times more water per unit of energy than conventional gas.[97]

Over time, continued drilling activity could significantly impact water resources and aquatic life depending on the number of wells drilled, the amount of water used per well and the source of water. Large-scale use of water could have serious ecosystem impacts and can reduce the availability of water for use by local communities and in land use activities, such as agriculture. Water use is already a potential constraint in northern B.C. In August 2010, the OGC suspended previously-approved water withdrawals in the Peace River basin due to severe drought conditions.[98]

Among the concerns regarding use of large volumes of water for shale gas production is the lack of infrastructure for moving the water and treating it efficiently. As a result, fracturing operations often require a large fleet of tanker trucks feeding the wellsite. In the example of a well requiring 15,000 m^3 of water brought in from another site (in the middle range of the list above), this

[93] ERCB, *Unconventional Gas Regulatory Framework.*

[94] Talisman and Canbriam have both applied to remove water from the reservoir, and permission has not yet been granted or denied. Statement by Mr. Bob Simpson in the B.C. Legislature, Wednesday, June 1, 2011 http://www.leg.bc.ca/hansard/39th3rd/h10601y.htm#39362:1425

[95] ERCB, *Unconventional Gas Regulatory Framework.*

[96] J. W. Ubinger, J.J. Walliser, C. Hall and R. Oltmanns, *Developing the Marcellus Shale: Environmental policy and planning recommendations for the development of the Marcellus Shale play in Pennsylvania* (Pennsylvania Environmental Council, 2010).

[97] International Energy Agency, *Golden Rules for a Golden Age of Gas*, Table 1.1.

[98] B.C. Oil and Gas Commission, *Suspension Of Surface Water Withdrawals (Peace River),* Directive 2010-05, August 11, 2010. http://www.bcogc.ca/document.aspx?documentID=858&type=.pdf

would represent 566 truckloads[99] (see section 3.1.6 for more information). Some companies have approached municipalities to buy water directly from them.[100]

Operators have focused on reducing water use, implementing permanent water pipelines and centralized treatment facilities, and looked for alternative fracture fluid options to reduce their use of water. They are also making increasing use of brackish and saline water sources, and implementing water recycling where possible.

Options for reducing use of fresh water include:

- **Sourcing water from deep aquifers** – Some water from deep formations is usable for hydraulic fracturing,[101] but water with extreme salinity may be economically prohibitive for use in shale gas operations, especially in remote areas where capital investment in order to access, lift, and treat saline water is more costly.[102] Pumping water from great depth and treating the associated salts and contaminants increases the greenhouse gas intensity of recovery. In Canada, regulations for sourcing deep groundwater vary between jurisdictions. Industry has undertaken some initiatives to increase use of saline water.[103]
- **Use of waste/recycled water** – Water sourced from municipal systems or flowback is being considered and/or implemented by some industry players. The B.C. Oil and Gas Commission estimated that 20% of the water used in hydraulic fracturing comes from reuse of flowback water.[104] By one estimate, it is technically and economically feasible to recycle 30 to 50% of all flowback fluid.[105] Some companies are now achieving recycle rates as high as 90%. Use of wastewater, as demonstrated by the Shell-Dawson Creek Reclaimed Water facility, could become more common.[106]
- **Use of propane or diesel as fracturing fluid** – Hydrocarbons in a gel form can be used in certain geological formations or in very cold climates.[107] However, these compounds are flammable, which makes them dangerous to handle, and contamination risks and disposal costs are higher.[108]

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[99] Based on a truck capacity of 36.5 m^3. From: R.L. Santoro, R.H. Howarth, A.R.. Ingraffea, *Indirect Emissions of Carbon Dioxide from Marcellus Shale Gas Development* (Agriculture, Energy, & Environment Program at Cornell University, 2011).

[100] Willms and Shier, LLP. *Shale gas*.

[101] B. Hayes, *Horn River Basin Subsurface Aquifer Characterization* (Geoscience B.C, 2011).

[102] B.C. Oil and Gas Commission, *Oil and Gas Water Use in British Columbia* (2010). www.bcogc.ca/document.aspx?documentID=856

[103] G.C. J. Coppola and R.C. Chachula, "Field Application of Very High Volume ESP Lift Systems for Shale Gas Fracture Water Supply in Horn River, Canada," presented at Society of Petroleum Engineers Annual Technical Conference and Exhibition, 30 October-2 November 2011, Denver, Colorado, USA.

[104] Campbell, and Horne, *Shale gas in British Columbia: Risks to B.C.'s water resources.*

[105] D. Manz, *Economic Treatment of Fracture Flow-Back Water to Recyclable Condition Using Physical Chemical Processes*, presented to the Groundwater Protection Council Annual Forum 2010. http://www.gwpc.org/meetings/forum/2010/proceedings/20Manz_David.pdf.

[106] "Water truck filling station," *Dawson Creek In The News,* November 2011. http://www.dawsoncreek.ca/wordpress/wp-content/uploads/2011/08/inTheNews201111.pdf

[107] D. Satya Gupta, "Unconventional Fracturing Fluids: What, Where and Why," presented to the EPA, 2010. http://www.epa.gov/hfstudy/unconventionalfracturingfluids-what-where-why.pdf

[108] International Energy Agency, *Golden Rules for a Golden Age of Gas*.

- **Use of carbon dioxide or nitrogen gas** – Fracturing with carbon dioxide or nitrogen gas can occur with gas used as a liquid or added to other liquids to improve viscosity.[109] However, these treatments may be costly and not feasible for remote operations or deep high-pressure formations.[110]

The optimum choice of fracturing fluid will depend on many factors: the availability of water, whether water recycling is included in the project, the properties of the shale reservoir being tapped, the drivers to reduce the usage of chemicals, and the fundamental economics of the project.

3.1.2 Contamination of water from methane

Considerable public attention has been focused on concerns that fracturing and well casing failures associated with shale gas development could result in contamination of shallow groundwater with methane. Two shale gas deposits in Canada are considered shallow: the Colorado shale (found in southern Alberta and Saskatchewan) at 300 metres and the Utica shale (found in southern Quebec) at 500 metres.[111]

Methane can be derived either from deep within shale layers (thermogenic origin) or from microbial activity near the surface (biogenic origin). Isotopic analysis of groundwater samples can be used to differentiate between sources of methane in water.[112] Six potential sources of methane in groundwater are described here:

- **Natural shallow sources –** Methane found in water wells within some shale gas areas, especially very shallow resources, can sometimes be traced to natural sources (biogenic).
- **Non-shale gas sources –** Methane could be present from abandoned gas wells from old drilling operations, from underground coal mining[113] or gas storage sites. For example, methane found in 49 of 91 water wells sampled in Pennsylvania by the U.S. Geological Survey was mostly derived from a nearby gas storage field, though there was some mixing of biogenic methane.[114]
- **Natural fractures –** Natural gas could travel from deeper areas to shallow groundwater through existing natural fractures found in some formations. This has been proposed in

[109] Ferus Wellsite Cryogenic Solutions, "Carbon Dioxide" http://www.ferus.ca/ProductsAndServices/CarbonDioxide.aspx and "Nitrogen" http://www.ferus.ca/ProductsAndServices/Nitrogen.aspx

[110] Satya Gupta, "Unconventional Fracturing Fluids."

[111] National Energy Board, *A Primer for Understanding Canadian Shale Gas*, Table 1.

[112] D. Rowe and K. Muehlenbachs, "Isotopic fingerprints of shallow gases in the Western Canadian sedimentary basin: tools for remediation of leaking heavy oil wells." *Organic Geochemistry* 30 (1999).

[113] J. Saiers, "Water Quality Issues Associated with Shale-Gas Development," presented at *Managing the risks of shale gas: Identifying a pathway toward responsible development,* Resources for the Future, Washington, DC, November 14, 2011.
http://www.rff.org/Documents/Events/Seminars/111114_Managing_the_Risks_of_Shale_Gas/Saiers%20Nov%2014%20FINAL.pdf

[114] J. Breen, K. Revesz, F. Baldassare and S. McAuley, *Natural Gases in Ground Water near Tioga Junction, Tioga County, North-Central Pennsylvania - Occurrence and Use of Isotopes to Determine Origins*, USGS Scientific Investigations Report 2007-5085 (2007). http://pubs.usgs.gov/sir/2007/5085/pdf/sir2007-5085.pdf.

Texas in parts of the Barnett Shale region where contamination of water was detected by the EPA in nearby residences.[115]

- **Hydraulic fracturing creating new vertical cracks –** Fracturing could create unexpectedly long pathways for gas and liquids to migrate upwards, potentially contaminating groundwater, depending on the depth of the gas deposit. Most Canadian shale gas deposits range from a minimum of several hundred to several thousand metres below the surface — much deeper than the typical deepest extent of fresh groundwater that could be sourced for human or animal needs.[116] Several major studies have indicated that groundwater contamination through this route is unlikely in all but the shallowest gas formations due to the significant vertical separation and numerous geological barriers that would need to be bypassed.[117,118,119,120] A recent study of fracturing operations in Europe and Africa supported this, finding that 99% of fractures created were less than 350 metres from the lateral, and that none of the fractures analyzed spread more than 600 metres from the lateral.[121]
- **Weak or inadequate casing and cementing –** Several major reports have arrived at the conclusion that weaknesses or inadequacies in casing and cementing are major routes for methane contamination.[122]

  Failure of well-bore casing and cementing are not unique to unconventional resource extraction or hydraulic fracturing, but some authors have hypothesized that repeated fracturing events weaken cementing and loosen casing.[123] The repeated stresses on the well from multiple high-pressure fracture events mean that there is increased pressure on

[115] Railroad Commission of Texas, *Commission called hearing to consider whether operation of the Range production company Butler unit well no. 1H (RRC ID 253732) and Teal unit well no 1H (RRC ID 253729) in the Newark, East (Barnet Shale) Field, Hood Country, Texas, are causing or contributing to the contamination of certain domestic wells in Park Country, Texas*, Oil and Gas Docket No. 7B-0268629, March 11, 2011. http://www.rrc.state.tx.us/meetings/ogpfd/RangePFD-03-11-11.pdf

[116] National Energy Board, *A Primer for Understanding Canadian Shale Gas*, 15.

[117] Ground Water Protection Council and ALL Consulting, *Modern Shale Gas Development in the United States: A Primer*, prepared for U.S. Department of Energy (2009), 53–54. http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf

[118] Energy Institute, *Fact-Based Regulation for Environmental Protection in Shale Gas Development*.

[119] S. Osborn, A. Vengosh, N. Warner, and R. Jackson, "Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing," *Proceedings of the National Academy of Sciences*. 108, no. 20 (2011). http://www.pnas. org/content/108/20/8172.full.pdf

[120] New York State Department of Environmental Conservation, *Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program* (2011). http://www.dec.ny.gov/energy/75370.html

[121] R.S. Davies, A. Mathias, J. Moss, S. Hustoft, L. Newport, "Hydraulic fractures: How far can they go?" *Marine and Petroleum Geology* 37, no. 1 (2012). http://dx.doi.org/10.1016/j.marpetgeo.2012.04.001

[122] Osborn et al., "Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing." see also

[123] Comment by K. Muehlenbachs, in A. Nikiforuk, "Fracking Contamination 'Will Get Worse': Alberta Expert," *The Tyee,* December 19, 2011. http://thetyee.ca/News/2011/12/19/Fracking-Contamination/print.html

the well, regardless of good well design and casing.[124] Casing damage has also been caused by erosion from propping sand scouring the casing.[125]

A major study from Duke University found a direct correlation between methane contamination and distance to shale gas activity, and isotopic analysis determined that the gas was thermogenic in origin. They sampled 60 residential drinking water wells, and found those near active drilling sites were contaminated with methane at levels 17 times higher than those found in wells in areas without drilling; some wells constituted a potential explosion hazard.[126] The Duke authors did not find a correlation between fracturing fluid additives or high salinity and distance to shale gas operations, and hypothesized that the main method of contamination was migration of gases through leaky casing and cementing. Isotopic analysis of gas that has been found in well casings suggest that methane can come from areas of the well other than the target formation, in spite of the casing, resulting in contamination.[127]

- **Blowouts –** Blowouts are uncontrolled fluid releases caused by unexpected high pressures or failure of wellbore integrity or valves. It is thought that shale gas wells have a greater risk of blowout than conventional wells due to the high pressures of fracturing fluid during hydraulic fracturing operations.[128] At least two shale gas well blowouts have occurred recently in the U.S.[129] In Canada, hydraulic fracturing was implicated as the cause of blowout in another well near Innisfail, Alberta.[130] A blowout caused a rig to catch fire near Hudson's Hope, but there were no injuries or reported health effects.[131]

Common to the incidents mentioned is the uncertainty of origin of the contamination. There is little to no baseline (pre-fracturing) data on groundwater quality, and on the isotopic fingerprints of methane from non-target sources nearby (e.g., other formations, legacy wells, natural seeps, springs and soil).[132] This information is essential to determine if and how shale gas development and associated methane is affecting water quality.

Lack of knowledge of the characteristics, movement and volume of groundwater has also confounded discussions of shale gas impacts. For example, the Quebec Environment Ministry

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[124] International Energy Agency, *Golden Rules for a Golden Age of Gas.*

[125] B.C. Oil and Gas Commission, *Wellsite Failure Investigation Prompts New Directive for Gas Wellsites in B.C.*, Directive 2010-06, November 23, 2010. http://www.bcogc.ca/document.aspx?documentID=1028&type=.pdf

[126] Osborn et al., "Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing."

[127] K. Muehlenbachs, "Identifying the source of fugitive methane associated with Shale Gas Development, updated with new data, Jan 2012," originally presented at *Managing the risks of shale gas: Identifying a pathway toward responsible development*, Resources for the Future, Washington, DC, November 14, 2011. http://www.rff.org/Documents/Events/Seminars/111114_Managing_the_Risks_of_Shale_Gas/Mulenbachs%20Nov%2014FINAL.pdf

[128] Energy Institute, *Fact-Based Regulation for Environmental Protection in Shale Gas Development*.

[129] C. Michaels, J. Simpson and W. Wegner, *Fractured Communities: Case Studies of the Environmental Impacts of Industrial Gas Drilling* (Riverkeeper, 2010).

[130] *Edmonton Journal*, "Fracking suspected in Innisfail blowout," January 17 2012. http://www.edmontonjournal.com/business/Fracking+suspected+Innisfail+blowout/6006761/story.html

[131] *Energetic City*, "No risk to public health from Suncor rig blowout," March 13, 2012. http://energeticcity.ca/article/news/2012/03/10/suncor-rig-blowout-near-hudsons-hope

[132] Muehlenbachs, "Identifying the source of fugitive methane associated with Shale Gas Development."

acknowledged that its groundwater mapping program does not currently cover all the areas targeted for shale gas production and does not provide enough information about the depth of the freshwater formation to ensure that surface casings of natural gas wells will be deep enough to protect fresh water.[133] Similarly, the B.C. Auditor General concluded that the current knowledge about groundwater in the province is not adequate to ensure that withdrawals will be sustainable.[134]

The EPA has commenced a study of groundwater and risks from hydraulic fracturing. They plan to identify potential contamination of drinking water resources, and to identify the factors that may lead to human exposure and risks.[135] Similarly the Council of Canadian Academies has convened an Expert Panel to investigate the environmental impacts of shale gas extraction.[136] New Brunswick has recently announced new regulations that will require testing of water prior to development, and some operators have committed themselves to baseline groundwater characterization.[137]

3.1.3 Contamination of water from fracturing fluid

Fracturing fluid is composed of water, proppant (sand or ceramic beads), and chemical additives. The proportion of additives ranges from well to well, but Table 2 presents a general overview of the components and their volume.

Table 2: Composition and purpose of typical fracturing fluid components

Constituent	Purpose	% by volume	Volume per well* (m^3)
Water and sand	Cracks rock and hold cracks open	99.5	14 925.00
Acids	Dissolves minerals and initiates crack in rock	0.123	18.45
Friction reducer	Minimizes friction between fluid and pipe	0.088	13.20
Surfactants	Increases viscosity of fluid so it can hold the proppant in suspension	0.085	12.75
Salts	Creates a brine carrier fluid	0.06	9.00

[133] Bureau d'audiences publiques sur l'environnement, Développement durable de l'industrie des gaz de schiste au Québec, document DQ29.1. Available at http://www.bape.gouv. qc.ca/sections/mandats/Gaz_de_schiste/ documents/liste_doc-DT-DQ-DM.htm#DQ.

[134] B.C. Auditor General, *An Audit of the Management of Groundwater Resources in British Columbia,* Report 8, December 2010.

[135] U.S. EPA, *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources.* (2011). http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/FINAL-STUDY-PLAN-HF_Web_2.pdf

[136] Council of Canadian Academies, "Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction." http://www.scienceadvice.ca/en/assessments/in-progress/shale-gas.aspx

[137] Government of New Brunswick *Stronger requirements for oil and natural gas exploration* http://www2.gnb.ca/content/dam/gnb/Corporate/pdf/ShaleGas/en/ExplorationRequirements.pdf; Shell, *Shell Onshore Tight Sand/Shale Oil & Gas Operating Principles* (2012). http://www-static.shell.com/static/usa/downloads/onshore/onshore_principles_fact_sheet2.pdf

Scale inhibitors	Prevents scale deposit in pipe	0.043	6.45
pH adjusting agent	Maintains pH to keep chemicals effective	0.011	1.65
Iron control	Prevents precipitation of oxides	0.004	0.60
Corrosion inhibitors	Prevents pipe corrosion	0.002	0.30
Biocides	Minimizes growth of bacteria to stop the formation of H_2S	0.001	0.15

*Assuming 15 000 m^3 of fluid is used per well

Source: Table recreated from Gregory et al.,[138] using data from EPA and API.

While the additives make up a small percentage of fracturing fluids, the overall volume of fluid is large, and thus substantial amounts of these additives are used. Information about fracturing fluids used in the U.S. suggests that some of the additives used are carcinogens, meaning that even small amounts could have a detrimental effect on health if humans or wildlife are exposed to them.[139] In B.C., the use of toxic drilling additives is restricted until cementing has sealed off the shallow freshwater zone (up to 600 metres in depth).[140] The B.C. Oil and Gas Activities Act allows hydraulic fracturing at depths less than 600 metres, provided with increased scrutiny and engineering support.[141]

Contamination of water from fracturing fluid could theoretically occur in a number of ways:

- Spills from trucks or storage tanks or pipelines.
- Leakage or overflow from improperly lined storage tanks or ponds, which may flow on the surface or percolate downwards into groundwater.
- Improper disposal or illegal discharge of fracturing fluids.

Temporary storage tanks, storage pits, transport trucks and pipelines can all leak or spill. A number of spills and leaks associated with shale gas development have been identified by regulatory agencies in the U.S.[142] Spills of wastewater are a familiar concern in the conventional upstream oil and gas industry and these spills of produced water generally far exceed spills of oil by volume. In Alberta, oil and gas companies spilled 24.6 million litres of produced water in 2010.[143] A spill of approximately 20 cubic metres of produced fluid from a shale gas operation in

[138] K.B. Gregory, R.D. Vidic, D.A. Dzombak, "Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing," *Elements* 7 no. 3 (2011).

[139] Committee on Energy and Commerce, "Committee Democrats Release New Report Detailing Hydraulic Fracturing Products," news release, April 16 2011. http://democrats.energycommerce.house.gov/index.php?q=news/committee-democrats-release-new-report-detailing-hydraulic-fracturing-products

[140] Willms and Shier, LLP., *Shale gas*.

[141] Government of British Columbian, *B.C. Oil and Gas Activities Act*, Section 21. http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/536427494#section21

[142] C. Michaels, J. Simpson and W. Wegner, *Fractured Communities.*

[143] Energy Resources Conservation Board, "Field Surveillance and Operations Branch Provincial Summary 2010 ST57-2011:", 2011, http://www.ercb.ca/docs/products/STs/ST57-2011.pdf

northern B.C. in 2011 killed at least one cow.[144] Because shale gas development in the U.S. often occurs in residential, rural or even urban setting, and these regions mostly have a higher population density than Canada, spills and leaks are more likely to be noticed and reported quickly by nearby residents, as compared to Canada (and Northeast B.C. in particular), where development may occur out of sight in less densely-populated zones.

Voluntary and Mandatory Disclosure of fracturing fluids

A great amount of the public and media attention on fracturing issues in the U.S. has been on the disclosure of components of fracturing fluid. Having publicly available information about the chemical composition of fracture additives would help in identifying the compounds that should be tested for when drinking or groundwater is being sampled. Without this information, testing for all potential compounds is a lengthy and expensive process. At the same time, companies have concerns with regards to intellectual property associated with the constituents in fracture fluids.

In the U.S., this issue has been controversial[145] Several U.S. states (such as Wyoming and Pennsylvania) now require disclosure to regulators.[146] Federally, the U.S. Department of the Interior has released draft regulations that would require operators to release information about fracture fluids for activities on federal lands within a month after fracturing activities have been completed.[147] In 2011, the industry began a systematic process of voluntary disclosure through the www.Fracfocus.org website.

In Canada, B.C. now requires full public disclosure of fracturing fluids with the exemption of proprietary compounds, and has launched www.fracfocus.ca in collaboration with industry to enable this disclosure, both in BC and across Canada.[148] Quebec has indicated that they will require records of all fracturing fluids to be maintained,[149] but it is not clear if this will necessarily released to regulators or the public. Federally, companies are generally required to report substances injected underground to the National Pollutant Release Inventory, but oil and gas wells are currently exempted from the inventory.[150]

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[144] Ben Parfitt, "A toxic spill and communications chill," *Canadian Centre for Policy Alternatives: Policy Note*, March 6, 2012. http://www.policynote.ca/a-toxic-spill-and-communications-chill/

[145] e.g. the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act (H.R. 2766), introduced by Democrats in June 2009.

[146] ERCB, *Unconventional Gas Regulatory Framework*.

[147] U.S. Department of the Interior, "Interior Releases Draft Rule Requiring Public Disclosure of Chemicals Used in Hydraulic Fracturing on Public and Indian Lands," press release, May 4, 2012. http://www.doi.gov/news/pressreleases/Interior-Releases-Draft-Rule-Requiring-Public-Disclosure-of-Chemicals-Used-in-Hydraulic-Fracturing-on-Public-and-Indian-Lands.cfm

[148] The policy exempts "proprietary components in accordance with the Trade Secrets provisions of the *Federal Hazardous Material Information Review Act*." B.C. Oil and Gas Commission, *Submission Information for Disclosure of Hydraulic Fracturing Fluids***,** Industry Bulletin 2011-33, December 19, 2011. http://www.bcogc.ca/document.aspx?documentID=1207&type=.pdf ; www.fracfocus.ca

[149] Ministère du Développement durable, de l'Environnement et des Parcs, « Évaluation environnementale stratégique – Adoption des mesures transitoires », news release, May 5, 2011. http://www.mddep.gouv.qc.ca/infuseur/communique.asp?no=1855.

[150] Environment Canada, *Guide for Reporting to the National Pollutant Release Inventory (NPRI) 009* (2010). http://www.ec.gc.ca/inrp-npri/C33ABEE5-6DE9-4843-8AF7-BDC7505893B3/Guide-for- Reporting-to-the-NPRI-009.pdf.

3.1.4 Waste treatment and disposal

Water management, including flowback treatment and disposal, was identified as the largest challenge of shale gas development by a recent study by the Massachusetts Institute of Technology.[151] Fluid flowing up out of the well may have a variety of constituents, including particulates, suspended solids, free oil, dissolved organics, volatile organics, hardness ions (calcium, magnesium, barium, strontium, sulfates, and carbonates), iron, silica, and bacteria.[152]

There are six established methods for waste disposal:

- **Treatment and re-use** – Treatment on-site for re-use reduces overall water use, reduces the costs of transportation, disposal and water management, and can reduce potential liability on site. Total dissolved solids (TDS) in flowback water are very high and can cause corrosion and damage to equipment, and surface bacteria can be transported through re-use of fluid, leading to cross-contamination of aquifers.[153] Removal of TDS through treatment is possible, but can be prohibitively expensive considering the volumes of water used in shale gas development.[154] Additionally, the chemical stability and effectiveness of some additives is reduced in the presence of salts.[155] The development of additives that retain their effectiveness in highly saline fluids could allow for greater reuse of flowback water. Options for treatment include reverse osmosis, distillation and crystallization, ion exchange and capacitive deionization, though these treatments are reported to be uneconomic at such a large scale.[156]
- **On-site containment** – In B.C. and Alberta, acceptable storage vessels to be used prior to treatment, recycling and/ or disposal include closed top tanks, open top tanks and lined, earthen excavations.[157] Evaporation in ponds is likely not a viable option in Canada because evaporation of highly saline water is very slow except in highly arid climates.[158] Other options include freeze–thaw evaporation which is possible only in cold climates.[159]

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[151] MIT Study Group, *The future of natural gas* (2010). http://web.mit.edu/mitei/research/studies/naturalgas.html

[152] National Energy Technology Laboratory, "Cost Effective Recovery of Low-TDS Frac Flowback Water for Re-use," Project DE-FE0000784. http://www.netl.doe.gov/technologies/oil-gas/Petroleum/projects/Environmental/Produced_Water/00784_FracWater.html

[153] R.Vidic, *Sustainable Water Management for Marcellus Shale Development* (2010). http://www.temple.edu/environment/NRDP_pics/shale/presentations_TUsummit/Vidic-Temple-2010.pdf

[154] Gregory et al., "Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing."

[155] Gregory et al., "Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing."

[156] Gregory et al., "Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing."

[157] ERCB, *Unconventional Gas Regulatory Framework*.

[158] Vidic, *Sustainable Water Management for Marcellus Shale Development.*

[159] J.A. Veil, M.G. Puder, D. Elcock, and R.J. Redweik Jr., *A White Paper describing produced water from production of crude oil, natural gas, and coal bed methane* prepared by Argonne National Laboratory, Argonne, Illinois for the U.S. Department of Energy, National Energy Technology Laboratory, W-31-109-Eng-38 (2004). www.evs.anl.gov/ pub/doc/ProducedWatersWP0401.pdf

- **Injection** – Most fracturing fluid in Canada is disposed of by injection below the freshwater zone.[160,161] However in areas where shale gas development is expected to be dense, space for disposal may be limited in capacity. For example, in the Barnett Shale in Texas, the ratio of disposal wells to gas-producing wells is slightly more than 1:1.[162] In contrast, the whole state of Pennsylvania has only seven disposal wells but over 200 producing wells.[163] The development of disposal wells can face regulatory challenges,[164] and the wells are costly (in the order of $1 to $2 million) to drill.[165] In Canada, disposal wells have been common in Alberta for disposal of produced water from conventional wells, and are growing more common in B.C. with unconventional development.[166]
- **Transport to a licensed waste treatment facility** – While not allowed in Canada, some shale gas producers in Pennsylvania have been sending wastewater to municipal sewage treatment plants, but most of these cannot deal with the high levels of dissolved salt, which is therefore discharged into waterways.[167] Most municipal treatment facilities use biological processes such as lagoons, trickling filters, or activated sludge to process municipal water. These systems are not designed to address elevated salinity in fracturing fluids. Some Pennsylvania regulations limit the proportion of fracturing fluid in the total volume of water treated at the facility (to less than 1%), and set standards for salinity in discharge waters.[168]
- **Surface discharge** – Surface discharge is not permitted in some jurisdictions and across Canada, but is allowed in some areas where disposal wells are not widely available. Use of fluid in artificial wetlands and agricultural has been proposed, but this is greatly limited to highly saline-tolerant organisms.[169] Surface disposal of water sourced from other regions can allow introduction of new and/or invasive species into the local aquatic

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[160] Mary Griffiths, *Protecting Water, Producing Gas: Minimizing the Impact of Coalbed Methane and Other Natural Gas Production on Alberta's Groundwater* (The Pembina Institute, 2007). http://www.pembina.org/pub/1434.

[161] B.C. Oil and Gas Commission, *Oil and Gas Water Use in British Columbia*, 7, 19.

[162] J. Tintera, Railroad Commission of Texas, "The Regulatory Framework of Saltwater Disposal 2008," presentation to Fort Worth Business Press Barnett Shale Symposium, Fort Worth, Texas, February 29, 2008. http://www.barnettshalenews.com/documents/Tinterra%20SW%20FtWorth4.pdf

[163] Gregory et al., "Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing."

[164] J.D. Arthur, B. Bohm and M. Layne, "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," presented at The Ground Water Protection Council 2008 Annual Forum, Cincinnati, OH, September 21–24, 2008.

[165] Vidic, *Sustainable Water Management for Marcellus Shale Development.*

[166] B.C. Ministry of Environment, "Procedure for Authorizing Deepwell Disposal of Wastes." http://www.env.gov.bc.ca/epd/industrial/oil_gas/deepwell_wastes.htm

[167] John Veil, *Water Management Technologies Used by Marcellus Shale Gas Producers*, ANL/EVS/R-10/3, prepared by Argonne National Laboratory for the U.S. Department of Energy, National Energy Technology Laboratory (2010), 19–20.

[168] Gregory et al., "Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing."

[169] Veil et al., *A White Paper describing produced water from production of crude oil, natural gas, and coal bed methane*.

ecosystem.[170] The EPA has recently released a schedule for developing standards for wastewater treatment for shale gas and coal bed methane.[171]

An issue that confounds safe disposal of fracturing fluids are wastes with naturally occurring radioactive materials (called NORM). NORM are derived from elements such as uranium, radium and radon that break down and are dissolved in low concentrations in groundwater or subsurface material. Traces of radioactivity on oil and gas waste and equipment has been observed in conventional gas development from a number of sites. The Marcellus shale appears to have higher levels of NORM than other shale gas formations in the U.S.[172]

In Canada, management of NORM is a provincial responsibility (unless concentrations are very high), but federal guidelines have been set for worker exposure and handling of NORM.[173] For aquatic NORM, the limit for release of material is based on human exposure.[174] Downhole disposal of NORM-containing fluids is the common way to manage the material, and thus this issue may not be as pressing in Canada where downhole disposal is standard.[175]

3.1.5 Local air quality

Air emissions from shale gas operations occur during drilling and fracturing as well as from infrastructure and facilities such as pipelines and compressors. The types of air emissions from shale gas development are not significantly different than those associated with conventional oil and gas development.

3.1.6 Land use and biodiversity impacts

A number of surface impacts are associated with shale gas development, some of which have already been mentioned above. While an individual well or well pad has a predictable footprint and set of associated impacts, it is also essential to address the cumulative effects of multiple operators in a given area which may create unforeseen effects.

Land use impacts associated with development of shale gas resources are similar to those found in development of conventional resources, save for a few key differences. Because shale gas formations are less permeable and require more intensive activities to extract a similar volume of

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[170] D.J. Soeder, "The Marcellus Shale: Resources and Reservations," *Eos* 91(2010).

[171] U.S. EPA, "EPA Announces Schedule to Develop Natural Gas Wastewater Standards," news release, October 20, 2011. http://yosemite.epa.gov/opa/admpress.nsf/0/91E7FADB4B114C4A8525792F00542001

[172] New York State Department of Environmental Conservation, *Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program*, Chapter 7.

[173] Health Canada, *Canadian Guidelines for the Management of Naturally Occurring Radioactive Materials (NORM)* (2000). http://www.hc-sc.gc.ca/ewh-semt/pubs/contaminants/norm-mrn/index-eng.php

[174] E.g. the concentration in water at the point of release that would result in a dose of less than 0.3 mSv/a to a reference adult consuming water for an entire year, assuming a four- to ten-fold dilution in concentration between the NORM. From: Health Canada, *Canadian Guidelines for the Management of Naturally Occurring Radioactive Materials (NORM).*

[175] A. Lustgarten and ProPublica, "Natural Gas Drilling Produces Radioactive Wastewater," *Scientific American*, November 9, 2009. http://www.scientificamerican.com/article.cfm?id=marcellus-shale-natural-gas-drilling-radioactive-wastewater

gas, drilling and production activities often create a larger environmental footprint than conventional gas extraction.[176]

Shale gas extraction includes several activities that have impacts similar to conventional oil and gas development, including:

- **Exploration and seismic delineation** – Clearing of cut lines to allow access for seismic data collection creates linear disturbance on the landscape. Linear disturbances create changes in microclimate, can facilitate introduction of new and invasive species, and increase erosion and vulnerability to sudden disruptive events.[177,178] The ecological effects of edge are known to extend into adjacent forest; a number of bird and mammal species will avoid the forest habitat near an edge.[179]
- **Clearing of land for infrastructure –** Each well pad typically occupies an area about 100 metres by 100 metres[180] and each well pad requires an access road and pipeline. Removal of forest or natural cover for the construction of well pads, roads and pipelines causes soil erosion (leading to water quality impacts) and increased habitat fragmentation.[181]
- **Drilling and casing –** Noise and activity during drilling can disturb wildlife,[182,183] and continuous noise can impact human health and well-being.[184]
- **Reclamation and abandonment –** At the end of a well's life it is required to be plugged and sealed, and surface lands reclaimed to the same state as it was prior to development.

Some impacts are more pronounced in shale gas development as compared to conventional development; these include:

- **Increased truck traffic** – In some areas, water used for hydraulic fracturing is transported by truck to the drill site. Truck traffic can create noise that can disturb wildlife, and create dust, air emissions and traffic hazards. Rural roads may need to be

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176 International Energy Agency, *Golden Rules for a Golden Age of Gas.*

177 F. Schmiegelow and M. Monkkonen, "Habitat loss and fragmentation in dynamic landscapes: Avian perspectives from the boreal forest," *Ecological Applications* 12 (2002).

178 J. Watling and M. Donnelly, "Fragments as Islands: A synthesis of faunal responses to habitat patchiness," *Conservation Biology* 20 (2006).

179 S. Dyer and R. Schnieder, *Death by a Thousand Cuts: Impact Of In Situ Oil Sands Development on Alberta's boreal forest* (The Pembina Institute, 2006); S. Dyer, et al., "Avoidance of industrial development by woodland caribou," *Journal of Wildlife Management* 65 (2001).

180 New York State Department of Environmental Conservation, *Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program.*

181 S.C. Tromboulak and C.A. Frissell, "Review of the ecological effects of roads on terrestrial and aquatic communities," *Conservation Biology* 14 (2000) 18-20; S. Jordaan, D. Keith, et al. "Quantifying land use of oil sands production: a life cycle perspective," *Environmental Research Letters* 4 (2009).

182 C. Bradshaw, S. Boutin and D. M. Hebert, "Effects of Petroleum Exploration on Woodland Caribou in Northeastern Alberta," *The Journal of Wildlife Management* 61 (1997).

183 C.D. Francis, J. Paritis, C. P. Ortega, A. Cruz, "Landscape patterns of avian habitat use and nest success are affected by chronic gas well compressor noise," Landscape Ecolology 26 no. 9 (2011).

184 S.A. Stansfeld and M.P. Matheson, "Noise pollution: non-auditory effects on health," *British Medical Bulletin* 68 (2003).

upgraded through widening or surfacing, and/or roads will need to be constructed where they do not exist.

- **Greater disturbance from noise** – Drilling and completion operations for unconventional gas wells may be considerably more disruptive to local landowners and wildlife than conventional gas or oil drilling. Extended periods (24–36 months) of virtually continuous industrial activity at a single, large well pad site will be necessary to drill and complete numerous wells.
- **Potential greater surface footprint** – It appears that the surface footprint per well for unconventional gas is smaller than conventional gas (as much as one-tenth the size),[185] assuming that a directionally-drilled multi-well pad needs fewer access roads. However, in light of more rapid gas production decline rates, it may be necessary to more frequently drill new wells to keep production levels stable. The unit of land disturbed per unit of energy produced for shale gas may therefore be greater than conventional gas.
- **Potential associated infrastructure** – In B.C. the possibility of linking shale gas development areas and LNG terminals to the electrical grid has been discussed. If so, large hydro and wind projects, natural gas generators, and associated transmission lines and pipelines may be required.

3.1.6.1 Pipelines

Environmental impacts associated with gas pipelines are well known, such as forest fragmentation, disturbance during construction, and air pollution from leakage. It is however the density of pipelines on the landscape that may be most significant with shale gas development. Canada already has 480,000 km of natural gas pipeline[186] and it is expected that more capacity will be needed to transport the increased production in natural gas. Three major pipelines were recently approved:

- The NOVA Gas Transmission Ltd. Northwest Mainline Expansion, three sections of pipeline in Alberta and northern B.C.[187]
- The 700-km Vantage pipeline that will transport ethane from North Dakota to a facility near Empress, Alberta, while following the general route of the existing Foothills pipeline.[188]
- The TransCanada Horn River pipeline, a 72-kilometre extension of the Alberta System running from the Ekwan Pipeline north to the Horn River area.[189]

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[185] New York State Department of Environmental Conservation, *Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program*.

[186] G. Caron, "Security Management at the National Energy Board," presented at the 6th International Public Safety/Counterterrorism Conference, Quebec City, April 24, 2007.

[187] National Energy Board, "NEB Approves Northwest Mainline Expansion," press release, February 28, 2012. http://www.neb-one.gc.ca/clf-nsi/rthnb/nwsrls/2012/nwsrls06-eng.html

[188] National Energy Board, "NEB Approves Vantage Pipeline Project," press release, January 19, 2012. http://www.neb-one.gc.ca/clf-nsi/rthnb/nwsrls/2012/nwsrls01-eng.html

[189] TransCanada. *Horn River Mainline Pipeline* http://www.transcanada.com/hornriverpipelineproject.html (accessed Mar. 22, 2012).

3.1.7 Induced Seismicity

Considerable public attention has focused on induced seismicity associated with shale gas development. Micro-seismicity is inherent in any hydraulic fracturing activity, as the formation of the cracks cause micro-seismic events. Events have also been related to mining, creation of hydro reservoirs, oil and gas extraction, long-term fluid injection and geothermal power generation.[190]

There have been sporadic surface seismic events that coincide with hydraulic fracturing activities, but this relationship is unclear. However surface seismicity can be linked to downhole waste disposal of fluid.[191] The seismic events associated with shale gas activity have been, so far, relatively small and have not caused any injury to humans or any serious damage to buildings or infrastructure.

Alberta reports that it is developing a database to monitor all seismic activity, to better understand relationships with factors such as oil and gas activity.[192]

While the connection between seismicity and hydraulic fracturing is not established, the relationship between seismicity and injection of waste is clear, and monitoring will be needed in seismically active areas.

3.2 National-scale issues

3.2.1 Energy Mix

There is an open debate on whether low-cost natural gas produced by hydraulic fracturing will act as a 'low carbon bridge' towards renewables, or whether it will compete with renewable energy sources for access to the grid, locking society into a high-emissions trajectory.[193,194] As the IEA reports, "there are factors working both against, and in favour of, renewables in a world of more abundant gas supplies. Depending on the type of policies in place, an abundance of natural gas might… postpone the moment at which renewable sources of energy become competitive without subsidies or… facilitate greater use of renewable energy, if policies are in place to support its deployment".

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[190] C. de Pater and S. Baisch, *Geo-mechanical Study of Bowland Shale Seismicity: Synthesis Report*, prepared for Cuadrilla Resources Ltd (2011). http://www.cuadrillaresources.com/wp-content/uploads/2012/02/Geomechanical-Study-of-Bowland-Shale-Seismicity_02-11-11.pdf

[191] S. Horton, "Disposal of hydrofracking waste fluid by injection into subsurface aquifers triggers earthquake swarm in central Arkansas with potential for damaging earthquake," *Seismological Research Letters* 83 (2012).

[192] Alberta Geological Survey, "Earthquakes in Alberta (Microseismicity)." http://www.ags.gov.ab.ca/geohazards/earthquakes.html

[193] J. Podesta and T. Wirth, *Natural Gas: A bridge fuel for the 21st century* (Center for American Progress, 2009).

[194] S. Brown and A. Krupnick, *Abundant Shale Gas Resources: Long-Term Implications for U.S. Natural Gas Markets* (Resources for the Future, 2010).

3.2.2 Greenhouse gas emissions

Greenhouse gases (GHGs) from shale gas production and consumption have been subject to increasing focus and scrutiny because of uncertainty of how emissions of shale gas compare with other forms of energy on a life cycle basis. It is indisputable that natural gas produces less carbon dioxide per unit of energy than burning oil or coal. However, energy sources must be compared on the full life cycle, including non-combustion (upstream) emissions, in order to assess the total climate change implications.

The quantification of emissions associated with upstream shale gas development is a primary point of controversy between proponents and critics, because the selection of key assumptions in modelling GHG emissions determines the outcomes of the analysis when comparing shale gas to other sources of power or transportation energy. According to the IEA, "Different assumptions about the level and impact of methane emissions can have a profound effect on the perception of gas as a "cleaner" fossil fuel…It is very important that efforts are redoubled to measure methane emissions more systematically".

There is a lack of good data on GHGs associated with shale gas production, transport and combustion in Canada. Analyses from the U.S. can provide valuable insights but need to be considered in light of differences in regulation and geological formation in Canada. Canada has announced that GHG regulations covering oil and gas operations are forthcoming.[195,196]

Both conventional and unconventional natural gas development emit GHGs from:

- Land use change (clearing of forest, disturbance of below-ground carbon stores in soil and peat)[197]
- Emissions associated with transportation of equipment and supplies to the drill site, and from the drilling rig and associated equipment[198]
- Upstream emissions from use of resources (e.g. steel, cement, fracture additives)[199]
- Leakage of CH_4 during transportation and storage (at valves, compressor stations and from pipeline damage)[200]
- Flaring (mostly CO_2)[201]
- Combustion of natural gas for processing and compression (mostly CO_2)[202]

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[195] Peter Kent, speech to Oakville Chamber of Commerce, Oakville, Ontario, February 22, 2012. http://www.ec.gc.ca/default.asp?lang=En&n=6F2DE1CA-1&news=813DA641-663C-4097-AA86-9E4FB6942F84

[196] Mike deSouza, "Canada pledges draft oil and gas regulations by 2013," *Canada.com,* May 17, 2012. http://blogs.canada.com/2012/05/17/canada-responds-to-international-climate-criticism-pledges-oil-and-gas-regulations-by-2013/

[197] M. Turetsky et al., "Current disturbance and the diminishing peatland carbon sink," *Geophysical Research Letters*, 29, 11 (2002). DOI :10.1029/2001GL014000.

[198] U.S. EPA, *Inventory of U.S. greenhouse gas emissions and sinks: 1990 – 2009,* EPA 430-R-11-005 (2011). http://www.epa.gov/climatechange/emissions/usinventoryreport.html.

[199] R.L. Santoro, R.H. Howarth, A.R.. Ingraffea, *Indirect Emissions of Carbon Dioxide from Marcellus Shale Gas Development* (Agriculture, Energy, & Environment Program at Cornell University, 2011).

[200] U.S. EPA, *Inventory of U.S. greenhouse gas emissions and sinks: 1990 – 2009.*

[201] U.S. EPA, *Inventory of U.S. greenhouse gas emissions and sinks: 1990 – 2009.*

Specific to shale gas development, additional or more intensive sources of GHGs are summarized here and discussed in more detail below:

- **Fluid transportation, use, treatment and disposal –** Due to the larger volume of fluids needed for shale gas development as compared to conventional, additional energy inputs are required to bring adequate volumes of water to the drill site (by pipeline or truck), to pump fluid down the well, to transport flowback and produced water to the injection well or treatment facility, and to treat this fluid for discharge or recycling.
- **Drilling distance –** The horizontal distance (laterals) are longer in shale gas development, requiring more intensive energy inputs.
- **Venting of flowback –** During the initial flowback period of the well, volumes of CH_4 may be vented to the atmosphere in jurisdictions where it is permitted.
- **Formation CO_2 –** Some shale formations have high concentrations of CO_2 which is stripped off and vented to the atmosphere.

Fluid transportation, use, treatment and disposal – Transporting fluid to and from the drill site by truck creates emissions from diesel engines. Assuming truck capacity of 26.5 m^3, approximately 650 truckloads would be required to transport water, fluid and waste to and from the drill site.[203] This translates into 0.4-0.5 g CO_2/MJ of energy produced.[204] Pumping the fluid down the well at high pressure also takes energy but it does not appear that these inputs have been well quantified.[205] Treatment of water also creates a relatively small amount of emissions (approximately 0.01-0.04 tonnes of CO_2 per well).[206]

Drilling distance – Directional drilling is more energy intensive than straight vertical. The additional greenhouse gas outputs associated with shale gas have been estimated at 15-75 tonnes of CO_2 as compared to a conventional well.[207] Energy intensity for shale gas drilling and pumps for fracturing has been estimated at 0.18-0.19 g CO_2 /MJ energy produced.[208]

Venting of flowback – Venting of methane during well completions and work overs involving hydraulic fracturing requires expelling the large volumes of fluid and gas from the well. Initially the flowback is 100% liquid, but this quickly becomes a mix of liquid and gas. The gas cannot be

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[202] J. Lelieveld, S. Lechtenböhmer, S.S. Assonov, C.A.M. Brenninkmeijer, C. Dienst, M. Fischedick, and T.Hanke, "Low methane leakage from gas pipelines," *Nature Brief Communications* 434 (2005).

[203] This assumes a fluid re-use rate of 40%. From Santoro et al., *Indirect Emissions of Carbon Dioxide from Marcellus Shale Gas Development*.

[204] Calculated from: Santoro et al., *Indirect Emissions of Carbon Dioxide from Marcellus Shale Gas Development*.

[205] (S and T)^2 Consultants Inc., *The Addition of Unconventional Natural Gas Supply to GHGenius*, prepared for Natural Resources Canada (2010).

[206] Based on 15-80% of fracturing fluid returning to the surface and no recycling, based on 0.406 tonnes CO_2/million litres being released to the atmosphere during water treatment. From *Towards Sustainability 2005-2006* (Water UK, 2006). http://www.water.org.uk/home/news/press-releases/towards-sustainability-report

[207] Based on use of 18.6 litres diesel used per metre drilled, for 300–1500 m of horizontal distance. R. Wood et al., *Shale gas: a provisional assessment of climate change and environmental impacts* (Tyndall Centre for Climate Change Research, 2011). http://www.tyndall.ac.uk/publications/technical-report/2011/shale-gas-provisional-assessment-climate-change-and-environmental

[208] Calculated from: Santoro et al., *Indirect Emissions of Carbon Dioxide from Marcellus Shale Gas Development*.

put into a pipeline until the pressure has sufficiently decreased to impose pipeline pressure, and thus methane at this stage is released to the atmosphere unless it is flared. To avoid venting, the well can be tied to a gathering pipeline or portable tanks prior to well completion or work over. Flaring of unprocessed gas can eliminate most of the methane, VOCs, and hazardous air pollutants from the gas, but does still emit other air pollutants and is not always permitted in highly populated areas or where there is a risk of forest fire.[209]

In Canada, B.C. does not permit venting unless the gas heating value, volume or flow rate is insufficient to support stable combustion[210] and where flaring or incineration is not practical.[211] Similarly, in Alberta, venting is permitted where flows will not support stable combustion but also when conservation of the gas is been determined to be economically infeasible (costs are greater than $50,000).[212] In Saskatchewan emissions from combined flaring and venting volumes must not exceed 900 m^3/day per site, above which the operator must determine economic feasibility (using the $50,000 threshold as well).[213] A report prepared for Natural Resources Canada stated that there was inadequate information available to determine whether venting and flaring rates for shale gas were different than unconventional, and so they were assumed to be the same.[214]

Formation CO_2 – Raw natural gas contains varying levels of carbon dioxide, known as formation carbon dioxide, which is stripped from raw natural gas during processing and is currently vented to the atmosphere. The exception is if there is carbon capture and storage facilities available, or the gas contains hydrogen sulphide.[215] Conventional natural gas in B.C. has historically been composed of 2–4% carbon dioxide prior to processing.[216] Natural gas from shale resources has varying levels of carbon dioxide; gas from the Horn River Basin is 12% CO_2, while the gas from the Montney Basin is only 1% CO_2 and Utica shale is even less.[217] The proportion of carbon dioxide in the gas production stream can increase over time in some shale gas resources.[218]

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[209] Energy Resources Conservation Board, *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* (2011). http://www.ercb.ca/directives/Directive060.pdf

[210] Government of British Columbia, *B.C. Oil and Gas Activities Act*, Drilling and Production Regulation, section 41.1, http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/536427494#section41

[211] B.C. Oil and Gas Commission, *Flaring, Incinerating and Venting Reduction Report for 2010* (2011). http://www.bcogc.ca/document.aspx?documentID=1206&type=.pdf\

[212] ERCB, *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting.*

[213] Saskatchewan Energy and Resources, *Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Directive S-10*, July 1, 2011.
http://www.er.gov.sk.ca/adx/aspx/adxGetMedia.aspx?DocID=5903,3383,3384,5460,2936,Documents&MediaID=37950&Filename=S-10+July+1+2011.pdf

[214] $(S\text{ and }T)^2$ Consultants Inc., *The Addition of Unconventional Natural Gas Supply to GHGenius*.

[215] The Eagleford Shale resources in Texas is the exception to this.

[216] M. Jaccard and B. Griffin, *Shale Gas and Climate Targets: Can they be reconciled?* (Pacific Institute for Climate Solutions, 2010). http://communications.uvic.ca/releases/release.php?display=release&id=1151

[217] National Energy Board, *A Primer for Understanding Canadian Shale Gas*.

[218] ERCB, *Unconventional Gas Regulatory Framework*.

Based on projections of activity levels for the Horn River and Montney basis, this vented CO_2 could create emissions of up to 4.3 Mt/year in 2020[219] creating a 16% increase in GHG emissions per unit of gas extracted and produced in B.C.[220]

[219] Jaccard and Griffin, *Shale Gas and Climate Targets: Can they be reconciled?*

[220] M. Horne, *Shale Gas in British Columbia: Risks to B.C.'s climate action objectives* (Pembina Institute, 2011).

4. Cumulative environmental effects and shale gas development

“Cumulative environmental effects” can be defined as changes or impacts to natural systems in a region caused by the aggregation of past, present and “reasonably foreseeable” future events, both natural and man-made.[221] These stressors can include oil and gas development as well as other human activities, climate change, and other drivers of change. Cumulative effects can be considered at three levels:

1. at the project level, where proponents can seek to predict the sum of future impacts to which their project is added;
2. at the regional scale, where impacts of the aggregation of activities on the overall ecosystem can be assessed; and
3. at the wider provincial or national policymaking and planning level, where high-level economic and industrial strategy and policy can be — but rarely is — informed by aggregate impact information.[222]

The regulatory structure is based on project-level environmental assessment and decision-making, whereas cumulative effects assessment is often beyond the capabilities of an individual project proponent, and the management of cumulative effects goes beyond the impacts and capabilities of individual industry sectors to span numerous government authorities.[223]

The discussion below focuses on the aggregate footprint of multiple shale gas related projects in a single region, without considering the wider context of development underway. The impacts that are relevant or unique to shale gas are discussed. **This is not intended to be a comprehensive summary of cumulative effects of shale gas development, as there is a high level of uncertainty with regards to the likely extent of planned shale gas development in key areas, other development plans in those areas, and the likely aggregate implications for the impacted natural systems.**

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[221] Aboriginal Affairs and Northern Development Canada, *A Citizen's Guide to Cumulative Effects* (2007). http://www.aadnc-aandc.gc.ca/eng/1100100023719#sub2

[222] B. Noble, *Cumulative environmental effects and the tyranny of small decisions: towards meaningful cumulative effects assessment and management,* Occasional paper No 8 (Natural Resources and Environmental Studies Institute, 2010).

[223] Noble, *Cumulative environmental effects and the tyranny of small decisions*.

4.1 Surface cumulative effects

While shale gas development may potentially occur in a number of jurisdictions in Canada, the most significant development so far has taken place in northern B.C. and thus this region is the focus of the following discussion. This region is home to the boreal woodland caribou, which is listed as a threatened species according to the federal Species at Risk Act and is known to be sensitive to industrial disturbances.[224] Other important species that could be impacted include the grizzly bear and songbirds. Surface impacts from seismic lines, wellpads, roads, and pipeline rights-of-way, including associated noise and other sensory disturbances, may threaten critical wildlife habitat.

Impacts from wells may in aggregate be significant given the projected scale of shale gas development in this region. While total production is uncertain due to economic and regulatory variables, CAPP predicts production of 1.8 million cubic feet per day of gas from the Horn River and Montney basins by 2020.[225] BC Hydro predicts a mid-range production from the Horn River Basin to be 4,900 million cubic feet per day by 2040.[226]

A key variable is the production lifetime of shale wells, which can be shorter than that of typical conventional wells. Additionally, production is quite variable within the same area (e.g. some wells give very good initial production and others perform poorly). Small or rapidly declining per-well production means that more shale wells must be drilled to keep production stable, leading to more overall surface impacts. The decline rates of shale gas vary between wells (by a factor of 2-3) and between shale resources (up to a factor of 10).[227] Estimates from a few years ago suggested that productivity of wells was small and dropped off quickly after the first production.[228] More recent information suggest that production per well is increasing, but this is concurrent with an increase in lateral distance drilled and number of fracturing events.[229]

Information from Canada is limited so far, but companies have reported high production volumes from the Horn River. All of these reported results should be viewed in the light of the small number of wells actually drilled in Canada so far. Only with a larger dataset can trends of production be accurately determined.

Well spacing has been identified as a concern in many jurisdictions. Well density for shale gas development is significantly higher than conventional well spacing in order to recover the resources efficiently. There may be efficiency in tightly-spaced wells, which could reduce total

[224] S. Dyer, et al., "Avoidance of industrial development by woodland caribou," *Journal of Wildlife Management* 65 (2001).

[225] Canadian Association of Petroleum Producers " Canada's Shale Gas," February 2010, slide 11, www.capp.ca/GetDoc.aspx?DocID=165107&DT=PDF

[226] BC Hydro, Integrated Resource Plan *Updated Inputs: Electricity Load Forecasts in Fort Nelson and the Horn River Basin,* Technical Advisory Committee summary brief to meeting #5, February 28 and 29, 2012. http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2012q1/IRP_TAC_Mtg05_SummaryBrief_FNHRB.Par.0001.File.IRP_TAC_Mtg05_SummaryBrief_FNHRB.pdf

[227] NY Times Documents: Federal Officials Quietly Question Shale Gas http://www.nytimes.com/interactive/us/natural-gas-drilling-down-documents-5.html

[228] IEA, *World Energy Outlook 2009*, 405.

[229] Krupnick, A. 2011. Shale Gas: Policy Context. Presentation at: Resources for the Future: Managing the risks of shale gas development.

road area required, but tightly spaced wells may also reduce wildlife habitat to small scattered islands that are not viable.[230] Some jurisdictions like Alberta have reduced the spacing requirements for unconventional wells to allow greater well density, as shown in Table 3.[231] Globally, unconventional gas wells can be found at a density of one well per square kilometre, and as high as 1.85 wells per square kilometre in some areas of Texas.[232]

Table 3: Well spacing requirements for conventional and unconventional wells

Jurisdiction	Conventional well spacing	Unconventional well spacing
B.C.	one well per 640 hectares[233]	About four wells per 640 hectares[234]
Alberta	two wells per 640 hectares[235]	No well spacing requirements[236]

Conventional oil and gas developed is typically reviewed on a well-by-well basis. Some jurisdictions are changing their definition of well to include multiple horizontal legs drilled from a single vertical wellbore.[237] The Alberta Energy Resources Conservation Board conducted a scan of jurisdictions that have shale gas development, and found that some have implemented procedures to assess environmental impacts and develop mitigation measures on a project-area basis (rather than assessing individual wells).[238] B.C. has taken a basin-planning approach in the Liard-Besa River Development Scheme, which required the preparation of an Environmental Stewardship Plan for the entire scheme.[239]

4.1.1 No Go Areas

Another key component for managing cumulative effects is the establishment of protected or "no-go" areas. These are unique and/or sensitive areas that should not be accessed for drilling and support infrastructure; they should be established through an appropriate process that takes into account traditional and local knowledge from local First Nations and the best available western science.

Examples of temporary no-go areas for shale gas development are the Resource Review Areas within boreal caribou ranges where no new petroleum and natural gas tenures will be granted for

[230] R. Schneider and S. Dyer, *Death by a Thousand Cuts: Impacts of in situ oil sands development on Alberta's boreal forest* (Pembina Institute, 2006).

[231] B.C. Oil And Gas Commission, *About Unconventional Gas*, Fact Sheet 3.

[232] International Energy Agency, *Golden Rules for a Golden Age of Gas.*

[233] B.C. Drilling and Production Regulations 362/98. Part 2.

[234] B.C. Oil And Gas Commission. *About Unconventional Gas*, Fact Sheet 3.

[235] Energy Resources Conservation Board, *Directive 065, Resources Applications for Oil and Gas Reservoirs*, October 6, 2011. http://www.ercb.ca/docs/documents/directives/Directive056.pdf

[236] This removal of spacing requirements also applies to the conventional gas zones in the base of the Colorado group. From: ERCB, *Directive 065, Resources Applications for Oil and Gas Reservoirs*,

[237] ERCB, *Unconventional Gas Regulatory Framework*.

[238] ERCB, *Unconventional Gas Regulatory Framework*.

[239] B.C. Oil and Gas Commission, Order 10-15-001 (Liard-Besa River Development Scheme), March 12, 2010. http://www.bcogc.ca/document.aspx?documentID=791&type=.pdf

the next five years, as established by the B.C. Ministry of Energy, Mines and Petroleum Resources in 2010.[240] B.C.'s OGC has also stated that specific habitat areas will be subject to management requirements as laid out in the new Oil and Gas Activities Act.[241] Other areas that could be considered for 'no go' status are those which are extensively perforated with legacy wells, where methane migration cannot be prevented.

4.2 Subsurface cumulative effects

In addition to the issues around water depletion discussed in section 3.1.1, the increasing number of wells penetrating the same formation means that interactions between wells are becoming more common, affecting well pressure and other operations. These events, called interwellbore communications, happened five times in Alberta[242] and 18 times in B.C.[243] in 2011. Communication events have occurred over distances of several hundred metres.[244] The B.C. OGC has advised operators to monitor for symptoms of well communications (such as loss of pressure) and notify other operators within 1000 metres of the wellbore that drilling and completion activities are occurring.

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[240] B.C. Ministry of Energy, Mines and Petroleum Resources, "Province Takes Action to Manage Boreal Caribou**,"** news release, June 21, 2010. http://www2.news.gov.bc.ca/news_releases_2009-2013/2010EMPR0027-000734.htm

[241] ERCB, *Unconventional Gas Regulatory Framework*.

[242] Energy Resources Conservation Board, *Bulletin 2012-02: Hydraulic Fracturing: Interwellbore Communication between Energy Wells*, January 23, 2012. http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_309_0_0_43/http%3B/ercbContent/publishedcontent/publish/ercb_home/industry_zone/rules__regulations__requirements/bulletins/bulletin_2012_02.aspx

[243] B.C. Oil and Gas Commission, *Communication during Fracture Stimulation*, Safety Advisory 2010-03, May 20, 2010. http://www.bcogc.ca/document.aspx?documentID=808&type=.pdf

[244] ERCB, *Unconventional Gas Regulatory Framework*.

5. Voluntary industry initiatives

5.1 Context

In Canada, many companies are seeking to harvest lessons from the U.S. shale gas experience, as well as from the experience of oil sands developers, to inspire a more proactive and collaborative approach to defining responsible shale gas development — which includes beyond-compliance (voluntary) environmental measures. These beyond-compliance environmental initiatives include investment in research and technology deployment, implementation of policies or programs that demonstrate environmental stewardship, and disclosure, outreach and communications to engage with stakeholders and tackle controversies head-on.

There are multiple reasons why industry should be interested in creating and implementing beyond-compliance environmental initiatives, which include:[245]

- Reducing stakeholder concern;
- Demonstrating 'responsible operatorship' / differentiating from peers; and
- Reducing the threat of more-punitive and heavy-handed regulation.

Additionally, these voluntary initiatives can benefit companies by helping to:

- Overcome physical or regulatory resource access constraints (e.g. lack of access to surface water, limits on waste disposal capacity, caps on air emissions, etc.)
- Reduce cost and improve recovery rates, versus business-as-usual
- Prepare for anticipated regulatory changes
- Earn a seat at the table in regulatory design conversations

There are, however, costs and risks to taking on these initiatives. The International Energy Agency estimates that implementation of their set of best environmental practices would increase the cost per well by 7%, but may actually decrease the cost of development of a gas field by 5% due to economies of scale.[246]

Companies may also be concerned that by taking specific measures in unique circumstances, they can inadvertently create precedents for economically-punitive blanket regulation (e.g. 'no good deed goes unpunished'). Moreover, companies are highly sensitive to over-stepping their limits into the realm of government jurisdiction. The boundary between the role of companies and the public sector is contentious and needs to be part of any discussion of voluntary initiatives.

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[245] O.Salzmann, A. Ionescu-Somers, U. Steger, "The business case for sustainability: literature review and research options," *European Management Journal* 23 (2005).

[246] International Energy Agency, *Golden Rules for a Golden Age of Gas.*

The section that follows provides a high-level summary of some relevant shale gas industry initiatives, as well as some examples of efforts in other sectors that may offer helpful models for moving towards better performance. Importantly, none of the activities cited are required as part of regulatory approvals for oil and gas exploration, production, and operations. These initiatives may be developed at a site or project level by a company, by a single company across many regions, by multiple companies working in the same region, or across the shale gas sector.

International standards exist for oil and gas operations from the International Organization for Standardization (ISO) and the American Petroleum Institute, along with subsidiary national and regional organizations. Many of these standards are incorporated into legislation. The focus of this paper is not an analysis of these established standards, but rather a summary and assessment of shale-gas-specific voluntary initiatives.

5.2 Scan of industry initiatives

There are multiple types of beyond-compliance initiatives relevant to shale gas development. These include:

R&D and science — Research and development of knowledge, technology or practices to understand, reduce or mitigate impacts. For shale gas development, this includes research to reduce water use, obtain water from alternative (non-freshwater) sources, create non-toxic fracturing additives, reduce surface footprint, or improve understanding of net greenhouse gas emissions. However, some drawbacks of R&D as a means for resolving environmental concerns include:

- A time delay in implementation,
- A lack of stakeholder inclusion in the process of priority setting and knowledge generation,
- A ‘rebound effect’ in which improvements in per-unit footprint result in more production within the same environmental envelope, rather than resulting in a smaller overall impact.

Principles and practices—High-level or specific commitments for operations and management, aimed at external stakeholders or internal constituencies (employees or contractors). These commitments are intended to clarify or to go beyond standard industry practices in the mitigation of environmental concerns or enhancement of environmental outcomes. This category includes operating principles such as those that have been articulated by Chesapeake Energy, Shell and Talisman Energy.

Policy advocacy— Actions to influence public policy associated with shale gas development, to raise the bar for the whole industry and publicly demonstrate willingness to meet or exceed policy and regulatory requirements.

Table 4 summarizes a number of publicly available, significant beyond-compliance initiatives for shale gas development. Each initiative is detailed below the table. Notably, with limited exceptions, our research turned up few examples of how service companies are engaging in beyond-compliance initiatives.

Table 4: Industry initiatives for beyond-compliance initiatives in shale gas operations

Scope	R&D and Science	Principles and practices	Policy advocacy
One company	Cuadrilla Resources seismicity study	Shell Dawson Creek Reclaimed water facility	Southwestern/ EDF Model Regulation
		Shell operating principles	
	Spectra carbon capture and storage project	Talisman operating principles	
		Talisman fracture fluid and infractions disclosure	
		Cheseapeake GreenFrac	
		Encana Responsible Products program	
		Haliburton CleanSuite program	
		Devon water recycling	
		Southwestern's Green Completions program	
		Tervita closed loop drilling system	
Multiple companies	Flowback water reuse guideline	Horn River Producers Group initiatives	
		Encana/Apache Debolt Aquifer project	
		Marcellus Shale Coalition guiding principles	
		CAPP principles	
Multiple companies plus stakeholders	Horn River and Montney water projects	Fracfocus	Sundre Producers and Operators Group (SPOG)
	EDF-Multi-company fugitive emissions study		

5.3 R&D initiatives

5.3.1 Cuadrilla Resources seismicity study

In response to a series of small seismic events in the Bowland Basin in Lancashire, U.K., Cuadrilla Resources commissioned a seismicity study by a panel of independent seismic experts.[247] It was found that hydraulic fracturing in combination with unusual geology led to the seismic activity. A series of recommendations were put forward on the establishment of a risk-

[247] *Geo-mechanical Study of Bowland Shale Seismicity*.

based[248] management framework to reduce the threat of unintended seismic impacts on infrastructure and people.

5.3.2 Spectra Energy carbon capture and storage project

Spectra Energy is assessing the feasibility of developing a carbon capture and storage project for their gas processing plant in Fort Nelson, B.C. This reservoir could hold up to two million tonnes of CO_2.[249] This carbon would be stored two kilometres underground in saline reservoirs. If completed as planned, this carbon capture and storage project would be one of the largest in the world.[250]

5.3.2.1 Industry flowback water re-use guidelines

CAPP and PTAC are developing guidance for companies seeking to minimize freshwater use by reusing flowback water in hydraulic fracture jobs. While there is cost and safety benefits, along with the potential reduction in freshwater demand, the reuse of flowback and produced water poses challenges in terms of certainty of performance of the resulting hydraulic fracturing fluid, and of impact on equipment. The recycled flowback will vary significantly from freshwater in terms of salinity, chemicals present (including residual fracture fluid chemicals), temperature and other properties. The work is being led by Schlumberger and MISWACO, and has been posted on PTAC's website.[251]

5.3.2.2 Horn River Aquifer Characterization and Montney Water Project

These projects, while headed by Geoscience BC, are in cooperation with industry in the Horn and Montney areas. The Horn River Basin Aquifer Characterization Project is designed to synthesize available geologic information about the basing and well data to identify aquifers capable of producing high volumes of water for sourcing fracturing fluid and for disposal wells.[252] Similarly, the Montney Water Project involves collecting, analyzing and interpreting available water information in the Montney to determine the potential for use of deep aquifers for fracture fluid and disposal.[253]

5.3.2.3 Environmental Defense Fund-Multi-company fugitive emissions study

A key question in determining the net greenhouse gas benefit of fuel switching from coal to natural gas is the extent to which methane is released in the process of shale gas production

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[248] In other words, greater care is requires in situations where the set of factors contributing to greater vulnerability to unintended seismic outcomes

[249] Spectra Energy, "Carbon Capture and Storage." http://www.spectraenergy.com/Responsibility/Climate-Change/Carbon-Capture-Storage/

[250] Spectra Energy, *Backgrounder: Proposed Fort Nelson Carbon Capture and Storage Project*. http://www.spectraenergy.com/content/documents/Climate_Change/CCS_Backgrounder.pdf

[251] Keith Minnich, Talisman Energy, "Project to Develop Flowback Water Reuse Guidelines for Hydraulic Fracturing Operations," presentated at PTAC 2012 Spring Water Forum. http://www.ptac.org/projects/151

[252] Geoscience BC, "Horn River Basin Aquifer Characterization Project." http://www.geosciencebc.com/s/HornRiverBasin.asp

[253] Geoscience BC, "The Montney Water Project." http://www.geosciencebc.com/s/Montney.asp

during flowback — when fluids, water and gases flow out of a well after drilling but before the gas is put into pipelines. Companies often burn or capture the produced gas during flowback, though some have equipment to capture it for clean-up and ultimate sales. To resolve the high level of controversy associated with the variance in practices and resulting emissions during completion and flowback, Environmental Defense Fund (EDF) is currently collaborating with industry and academic partners on a series of five scientific studies to measure methane leakage rates across the natural gas supply chain, including during production.[254] Partners include the University of Texas, Duke University, Harvard University, Boston University and eight major natural gas companies including Shell and Southwestern. EDF aims to complete the entire study by December 2013.[255] This approach establishes a model for joint fact-finding that could usefully be replicated in Canada in the Horn River and other regions.

5.4 Principles and practices

5.4.1 Shell Dawson Creek reclaimed water facility

Shell has agreed to provide $9.75 million to the community of Dawson Creek, B.C. for a water treatment facility to treat municipal wastewater. Shell has access to the first 3.4 million litres of treated water per day, and the town uses the remaining 1.1 million litres and contributes $1.5 million and upkeep costs.[256] This represents a win-win situation for both the community and the company in terms of water access.

5.4.2 Shell onshore tight sand/shale oil & gas operating principles

Shell has developed a set of operating principles[257] for unconventional resources, including specific commitments including:

- Safe and responsible design and construction of well and facilities, including eliminating the use of earthen pits for produced fluids prior to separation of hydrocarbons; using at least two barriers in wells, tanks, pits etc.; pressure testing for wellbore integrity prior to fracturing; preparing emergency response plans; conducting regular process safety reviews; disclosing fracture fluid chemical constituents; and supporting chemicals disclosure regulation.
- Protection and reduced use of groundwater and freshwater, including not operating in areas where it is not possible to isolate activities from potable groundwater; conducting baseline and ongoing potable groundwater testing; and minimizing water use "as reasonably practicable";

[254] Renee Schoof, "As natural gas production grows, questions arise about methane leaks," *McClatchy*, March 19, 2012. http://www.mcclatchydc.com/2012/03/18/142327/as-natural-gas-production-grows.html

[255] "As natural gas production grows, questions arise about methane leaks."

[256] Water truck filling station," *Dawson Creek In The News*, November 2011. http://www.dawsoncreek.ca/wordpress/wp- content/uploads/2011/08/inTheNews201111.pdf

[257] Shell Canada, *Shell Onshore Tight Sand/Shale Oil & Gas Operating Principles.*

- Protection of air quality and reduction of fugitive emissions, by developing emission reduction plans; by monitoring for fugitive emissions; and by mitigating or eliminating surface casing annulus venting[258];
- Reduction of the footprint, including design and operations considerations to limit or mitigate disturbance, noise and light; to understand and reduce impact on wildlife and livestock; and to reduce trucking through installation of pipelines and gathering systems where practicable and economically feasible;
- Engagement with local communities to provide information, promote local benefits and reduce impacts.

5.4.3 Talisman operating principles

Talisman Energy has developed shale operating principles[259] that include commitments (and in some instances performance indicators) such as:

- **Responsible operations** – Talisman's goal is to minimize adverse impacts on the environment and the communities. Some of the practices to accomplish this include emergency response plans at all locations; using two or more barriers in all wells and chemical storage; baseline groundwater testing; pressure testing wells for integrity prior to fracturing; maximizing flowback and produced water reuse; limiting noise, traffic and light; minimizing habitat fragmentation and operation in protected areas; and planning for reclamation and monitoring following operations; recovering gas during completions where practicable; and eliminating the use of diesel as a hydraulic fracturing additive.

- **Mutual benefits** – Talisman's goal is to delivering positive economic and development opportunities for communities where we operate. Some of the practices to accomplish this include supporting the development of capacity for local sourcing and economic benefits to government.

- **Transparency and Collaboration** – With the goal to work with stakeholders and conduct business to a high ethical standard, Talisman commits to active disclosure of progress and areas for improvement via regular publicly-available channels; disclosure of chemicals used by Talisman and by its suppliers; and to investigating concerns raised by stakeholders.

5.4.4 Talisman disclosure of fracturing fluid and regulatory infractions

For operations in the Marcellus Shale, Talisman reports all violations issues to the company by the Pennsylvania Department of Environmental Protection and how the company is responding

[258] Surface casing annulus vent flow is the potential flow of gas and/or liquids to the surface or into near-surface groundwater from deeper (non-target) formations due to flaws in the bonds between the ground, cement and steel pipe that encases the well.

[259] Talisman Energy, "Getting it right because it's important: Shale Operating Principles." http://www.talisman-energy.com/operations/north_america/shale-operating-principles.html.

to correct the issue. The goal of this disclosure is to assist the public in tracking violation trends and determining whether or not actions are successfully addressing risks.[260]

5.4.5 Chesapeake GreenFrac program

This program evaluates the types of chemical additives typically used in the process of hydraulic fracturing to determine their environmental impact. It also assesses each hydraulic fracturing job to identify chemicals that can be removed, and tests alternatives for remaining additives. The company claims that the program had reduced the number of additives used in fracture fluids by 25% of in most of its shale resources.[261]

5.4.6 Encana Responsible Products program

This program aims to reduce the use of fracture additives with the highest potential for health and environmental impacts. All hydraulic fracturing fluid products are assessed based on their potential risk to human health or the environment using a Responsible Product Assessment Tool, working with a third-party toxicology service provider (Intrinsik Environmental Sciences Inc). The tool uses government databases and information from Environment Canada, the European Union, the U.S. Environmental Protection Agency and the American Conference of Governmental Industrial Hygienists as the basis for its classification. As one outcome from this program, for example, Encana reports that it no longer uses any diesel, 2-Butoxyethanol (2-BE) or benzene in hydraulic fracturing operations.[262]

5.4.7 Haliburton CleanSuite program

Haliburton has developed a suite of research on technological options to reduce impact and/or use of chemicals of concern. This includes utilizing less impactful fracture additives, using UV light instead of biocide to control bacteria, reducing water use, increasing water recycling, and utilizing less toxic thickeners.[263]

5.4.8 Devon water recycling

In the Barnett Shale in Texas where water is limited, Devon has been using a mobile water recycling unit instead of trucking in water from long distances. This unit has been used since

[260] Talisman Energy, "How we're doing." http://www.talismanusa.com/how_we_operate/notices-of-violation/how-were-doing.html.

[261] Chesapeake Energy, "GreenFrac Program" http://www.chk.com/environment/drilling-and-production/pages/green-frac.aspx.

[262] Encana, "Responsible Products Program." http://www.encana.com/environment/water/fracturing/products.html; Intrinsik, "A Screening-Level Assessment Tool for Classifying Hydraulic Fracturing Fluids," presented to the PTAC 2012 Spring Water Forum. http://www.ptac.org/attachments/355/download

[263] Halliburton, "CleanSuite Technologies." http://www.halliburton.com/public/projects/pubsdata/hydraulic_fracturing/CleanSuite_Technologies.html

2005 to treat up to 660,000 litres of flowback water per day. The process involves boiling the fluid to separate clean water from dissolved solids.[264]

5.4.9 Southwestern's Green Completions program

Southwestern Energy Company has implemented 'Green Completions' at a majority of its gas wells.[265] It has also committed to use a number of additional technologies and practices to reduce emissions:[266]

- Using low-NOx or electric-drive compressor engines
- Redesigning blowdown and emergency shutdown practices
- Using flash tanks and vapor recovery systems to minimize emissions from glycol reboilers and condensate storage tanks
- Using infrared cameras to detect fugitive emissions
- Installing no-bleed pneumatic controls, air/fuel ratio controllers, and electric or solar powered pumps

5.4.10 Tervita closed loop drilling system

Borrow pits are used onsite during drilling operations both as sources of water, and in some instances for storage of flowback. Recognizing concerns associated with groundwater contamination and land footprint from these pits, a number of operators are working to eliminate the use of these pits in their operations.[267] In response to this need, service company Tervita has developed a 'closed loop' drilling system with a mobile unit that segregates waste streams from drilling fluids onsite, eliminating the need for open pits.[268]

5.4.11 Horn River Basin Producers Group initiatives

This group consists of 11 companies (Apache, ConocoPhillips, Devon, EnCana, EOG Resources, Imperial Oil, Nexen, Pengrowth, Suncor, Quicksilver and Stone Mountain) who are

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[264] Devon Energy, "Recycling efforts in North Texas reduce water needs." http://www.devonenergy.com/CorpResp/initiatives/Pages/Initiatives-WaterRecycling.aspx#terms?disclaimer=yes

[265] Jim Efstathiou Jr., "Drillers Say Costs Manageable From Pending Gas Emissions Rule," *Bloomberg*, April 17, 2012. http://www.bloomberg.com/news/2012-04-17/drillers-say-costs-manageable-from-pending-gas-emissions-rule.html

[266] Southwestern Energy, "Air." http://www.swn.com/responsibility/pages/air.aspx

[267] Shell for example has committed in its onshore operating principles to "eliminate the use of earthen pit systems for primary containment of produced and drilling fluids." Shell Canada, "Safety." http://www.shell.us/home/content/usa/aboutshell/shell_businesses/onshore/principles/safety/

[268] Tervita, "Closed Loop Systems." http://www.tervita.com/products-services/a-z-products-and-services/Pages/closed-loop-systems.aspx; Preston McEachern, Tervita, "Chemical Characteristics of Frac Flowback Water & Technologies Deployed to Recycle Water, Reduce Waste Volumes & Reduce Cost," presented at WaterTech conference, 2012. www.esaa-events.com/watertech/2012/pdf/P12.pdf

collaborating on environmental initiatives including sharing access roads and pipelines and researching surface and subsurface water usage.[269]

5.4.12 Encana/Apache Debolt Aquifer project

Encana and Apache operations in the Horn River access and treat water from the saline Debolt aquifer for use in fracturing operations, thereby avoiding use of surface water.[270]

5.4.13 Marcellus Shale Coalition guiding principles

The Marcellus Shale Coalition was formed in 2008 by numerous producers as board members, and a number of service companies as associates. The group states its commitment to responsible natural gas development.[271]

The group has stated a number of guiding principles for development, including creating the safest possible workplace, use of state-of-the-art environmental protection, continual improvement, use of local workforce, being responsible members of communities, encouraging dialogue about shale gas development and providing energy security and economic benefits.[272]

5.4.14 CAPP guiding principles for hydraulic fracturing

CAPP members have identified five principles for hydraulic fracturing, including:

- safeguarding regional surface and groundwater resources,
- measuring and disclosing water use,
- promoting development of fracture fluids with minimal environmental risks,
- supporting the disclosure of fracturing fluid additives and advancing, and;
- collaborating on technologies and best practices.[273]

These principles have been elaborated into voluntary operating practices at a higher level of specificity that could enable auditing. For example, the Wellbore Construction and Quality Assurance Operating Practice details key elements:

- "Surface casing will be installed and cemented to surface. The final casing string will be…cemented from the top of the target zone back…creating a continuous cement barrier from surface to the top of the target zone."
- "[T]he integrity of the wellbore should be confirmed by…pressure test."

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[269] Northern Rockies, "The Horn River Basin Producers Group." http://www.northernrockies.ca/EN/main/business/economic-development/OilGas/Horn_River_Basin/producers_Group.html

[270] Canadian Association of Petroleum Producers, "Debolt Water Treatment Project 2011." http://www.capp.ca/energySupply/innovationStories/Water/Pages/debolt.aspx

[271] Marcellus Shale Coalition, "About." http://marcelluscoalition.org/about/full-members/

[272] Marcellus Shale Coalition, "Guiding Principles." http://marcelluscoalition.org/about/guiding-principles/.

[273] Canadian Association of Petroleum Producers, "Guiding Principles for Hydraulic Fracturing." http://www.canadiannaturalgas.ca/issues-policy/fracking/guiding-principles-for-hydraulic-fracturing

- "Companies are expected to make their wellbore construction and quality assurance practices publicly available, as they relate to this practice."

5.4.15 FracFocus.ca (disclosure of hydraulic fracturing fluids)

In the U.S., concern associated with the chemicals being used in hydraulic fracturing led to the establishiment of FracFocus.org, a hydraulic fracturing chemical registry website launched in April 2011, jointly operated by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.[274] This site allows the public to search for chemicals used in hydraulic fracturing on a well-by-well basis, using their postal information.

In Canada, the B.C. Oil and Gas Commission established a similar database in January 2012, along with the mandatory obligation that companies disclose the list of ingredients used within 30 days of finishing completion operations. BC built FracFocus.ca to accommodate participation by other Canadian jurisdictions

5.5 Policy advocacy

5.5.1 Southwestern EDF model regulation

Southwestern Energy and Environmental Defense Fund have been working together to create a model regulatory framework for hydraulic fracturing through development of consensus among various stakeholders. Their framework includes recommendations regarding state-level regulations for disclosure of hydraulic fracturing fluids and enhanced monitoring of the integrity of well containment.[275]

5.5.2 Sundre Producers and Operators Group shale gas "Proactive Engagement"

Sundre Producers and Operators Group (SPOG) has been in operation since 1992. Begun as an effort to develop a coordinated emergency response plan associated with multi-company sour gas development in the Sundre town area, the SPOG is made up of oil and gas companies, and associate members made up of representatives of the various communities in and around Sundre, as well as representatives from government agencies. Among its activities are workshops, open houses, newsletters, and company-stakeholder dialogue. Through its "Proactive Engagement Process", SPOG convenes key stakeholders around the development of mutually-agreed-upon performance measures that companies can work toward to meet community concerns.[276] In 2012, SPOG launched a PEP on hydraulic fracturing, beginning with the collection of public comments

[274] FracFocus.org, "Welcome." http://fracfocus.org/welcome

[275] Environmental Defense Fund, "Natural gas policy." http://www.edf.org/energy/natural-gas-policy

[276] SPOG, "Structure." http://www.spog.ab.ca/structure.html

about concerns. The desired outcome is to develop management practices for hydraulic fracturing that may go beyond the present regulations to address community concerns.[277]

5.6 Understanding the effectiveness of industry initiatives

Companies — and internal champions within companies — are often challenged to evaluate the effectiveness of their beyond-compliance voluntary environmental initiatives. The primary test for any voluntary environmental initiative is whether firstly it meets its internal objective of driving a particular behavior or outcome and secondly on whether it wins stakeholder support and social license. Below are some other criteria for judging effectiveness.

1. **Targeted:** Are the commitments or initiatives targeting the issues of greatest concern to stakeholders?
2. **Appropriately scaled:** Are the resources and scale of the commitments or initiatives commensurate to the scale of the concern?
3. **Comprehensive:** Do the commitments or initiatives cover the full array of environmental concerns identified (see the list of environmental issues in Section 3).
4. **Specific and verifiable:** Are commitments and initiatives measurable, clearly articulated, and timebound? Are examples provided of how commitments will be implemented?
5. **Collaborative**: Was there stakeholder buy-in and engagement in developing the commitments or initiatives? Do they address cross-sector and regional development concerns?
6. **Positively influence policy and sector performance:** Do the commitments or initiatives support regulation and sector-wide initiatives that enable/promote responsible operation?
7. **Secure local stakeholder benefits and rights:** Do the commitments or initiatives ensure that communities demonstrably benefit from shale gas development, explain how their rights are viewed and protected, and provide mechanisms for/explain how disputes will be resolved?
8. **Transparent:** Is it clear how disclosure will take place, how the company will provide assurance of progress/compliance with commitments or initiatives?
9. **Demonstrably operationalized:** Does the commitment or initiative clearly go beyond a communications exercise to clarify how it will be embedded in business decision processes, training programs, scorecards and incentives?

5.7 Non-shale gas examples of industry voluntary initiatives

Collaboration among companies is a key driver of innovation of practices and technologies that reduce environmental impact, and reducing costs of these technologies. In both the U.S. and Canada, we see several groups of producers with aligned goals at a regional level (such as the Horn River Producers Group and the Marcellus Shale Coalition). However, there does not yet appear to be a group that is dedicated to technology development and innovation in shale gas.

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[277] SPOG, "Community and Industry." www.spog.ab.ca/communityandindustry.html; Lea Smaldon, "SPOG leads charge on best practices for fracking," *Mountain View Gazette*, February 21, 2012. http://www.mountainviewgazette.ca/article/20120221/MVG0801/302219979/0/mvg

5.7.1 Oil Sands Tailings Consortium

The Oil Sands Tailings Consortium was founded in December 2010 when seven of Canada's largest oilsands mining companies came together to share tailings research and technology in an effort to rapidly advance tailings management. Member companies include: Total E&P Canada, Imperial Oil, Shell Canada, Syncrude Canada, Teck Resources, Suncor Energy and Canadian Natural Resources Limited. The focus of the group is developing technological solutions for drying and management of tailings.[278] Technologies being tested include thickening, centrifugation, clarification and drying treatments for tailings. The group determined a number of working groups in areas where there were opportunities for collaboration after an information-sharing session. The group is funded by a cost-sharing formula.[279]

5.7.2 The Oil Sands Leadership Initiative

The Oil Sands Leadership Initiative (OSLI) is a collaborative network of companies operating in the Canadian oil sands. Each OSLI company works collaboratively to achieve significant improvements in environmental sustainability, social well-being and economic viability in individual company performance. Members include ConocoPhillips Canada, Nexen Inc., Statoil Canada, Suncor Energy Inc, Total E&P Canada Ltd. and Shell Canada.

OSLI has a four tier-structure:[280]

1. Steering Committee – which is composed of one representative from each member company. The committee is responsible for governance issues and development of the overall strategic plan.
2. Management Committee – which is again composed of one representative from each member company. This group is responsible for business planning and providing operational guidance.
3. Executive Director – who develops policies, procedures and governance structures and oversees the four OSLI working groups.[281]
4. Working Groups – OSLI is composed of four groups (land stewardship, water management, technology breakthrough and sustainable communities) which are composed of employees from each member company.

5.7.3 Canadian Oil Sands Innovation Alliance

Canada's Oil Sands Innovation Alliance (COSIA) is an alliance of oilsands producers focused on accelerating the pace of improvement in environmental performance in Canada's oilsands through collaborative action and innovation. The group was launched in 2012 and has 12

[278] CAPP, "Oil Sands Tailings Consortium." http://www.capp.ca/ENERGYSUPPLY/INNOVATIONSTORIES/LAND/Pages/OSTC.aspx

[279] TEC Edmonton, "Home-grown technology: The Oil Sands Tailings Consortium is cleaning up those tailings ponds." http://www.tecedmonton.com/TECTALKBLOG/tabid/435/entryid/85/Home-grown-technology-The-Oil-Sands-Tailings-Consortium-is-cleaning-up-those-tailings-ponds.aspx

[280] OSLI, "How OSLI works." http://www.osli.ca/about-osli/how-osli-works

[281] OSLI, "Executive Director." www.osli.ca/about-osli/how-osli-works-2/executive-director

member companies, though is open to future members and collaboration with other stakeholders.[282]

COSIA is led by a chief executive who reports to the member companies and oversees activities under four environmental priority areas (tailings, water, land and greenhouse gases)**.** The activities under these areas will be conducted by member company representatives with input from other stakeholders.[283]

[282]COSIA, "Canada's oil sands producers launch environmental performance alliance," news release, March 1, 2012. http://www.cosia.ca/2012/03/01/canadas-oil-sands-producers-launch-environmental-performance-alliance/

[283]COSIA, "Overview." http://www.cosia.ca/about-cosia/overview/

Annex 1. Life cycle GHG Emissions Comparison

Greenhouse gases from shale gas development need to be compared against other energy sources for similar end use to determine if they will help us in achieving our climate targets, both in the present and for future development. A controversial study published in April 2011 led by Cornell University Professor Robert Howarth concluded that emissions from shale gas were 30–100% higher than conventional gas, and 20–100% higher than coal over a 20-year time frame, but comparable to coal on a 100-year frame, based on analysis per unit of energy.[284]

There were a number of responses to the Howarth et al. paper. One of the main critiques of the results raised by a number of peers was around the decision to use a 20-year global warming time frame in addition to the standard 100 years. The 100-year horizon for evaluating the global warming effect is generally accepted and used to calculate national GHG emission inventories and in the Kyoto Protocol. Use of a 20-year horizon ignores the impact that CO_2 emitted today will continue to have more than 20 years into the future, and thus inflates the impact of methane relative to CO_2. However, it should be noted that there is an ongoing debate about the most appropriate time frame, and the 100-year time horizon strongly reduces the influence of short-lived GHGs relative to CO_2.[285] While results for both the 20-year and 100-year time frame were presented in the Howarth article, the results for 20-year timeframe were widely criticized.

Recent responses to the Howarth et al. paper include:

- NETL scientist Timothy Skone presented a lecture at Cornell that suggested that natural gas has 48% lower GHG emissions than coal on a 20-year time frame basis.[286] While this presentation was not a direct critique of Howarth's work, it did present very different findings of emissions.
- Hughes compared the Skone lecture with the Howarth paper and found that the differing conclusions were reached because Skone presented emissions data from natural gas as a whole rather than assessing the particular emissions of shale gas. While end use was not explicitly discussed in the Howarth et al. paper, the results were presented as grams of carbon per unit of heat energy, while Skone assumed that most natural gas would be used in electrical generation (in the more-efficient base load combined cycle component rather than the less-efficient natural gas-fired electricity generation). When the Howarth and Skone results were examined over the same time frame and same end-use assumptions, Hughes found that the results were not significantly different: that when looking at both the existing electricity generating fleets and best-in-class electricity generation

[284] R. Howarth, R. Santoro and A. Ingraffea, "Methane and the greenhouse-gas footprint of natural gas from shale formations." Letter, *Climatic Change* 106 (2011). http://www.springerlink.com/content/e384226wr4160653/

[285] D.T. Shindell et al., "Improved attribution of climate forcing to emissions," *Science* 326 (2009).

[286] T. Skone, NETL, "Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States," presented to the Cornell University lecture series on unconventional natural gas development, May 12, 2012. http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&PubId=386

technologies, shale gas full-cycle emissions are 31–53% higher than coal when examined over a 20-year time frame, but 3–34% lower than coal on a 100-year time frame.[287]

- Colleagues of Howarth at Cornell (Cathles et al.) also criticized Howarth's data sources for leakage values, and that the gas-to-coal comparison was done on a per-unit of energy basis, rather than per-unit of electricity, which takes into account the inherent differences in efficiency between electrical generation using coal versus electricity generation using gas. Cathles et al. concluded that shale gas GHGs are 50–64% lower than coal over a 100-year time frame.[288]
- Wang et al. also assessed GHGs of coal and shale gas and found that shale gas emissions are 87–171% of coal in the 20-year time frame and 12–36% less than coal in the 100-year time frame when efficiencies in power generation for natural gas are taken into account.[289]
- Jiang et al. found that life cycle emissions from Marcellus shale are comparable to those of imported liquefied natural gas and 20–50% lower than coal for production of electricity using a 100-year time frame.[290]
- The updated EPA GHG inventory in April 2011 shows a two-fold increase in total methane emissions from natural gas as compared to previous assessments.[291]
- A paper authored by Shell Canada representatives found that shale gas produces an average of 1.8–2.4% more emissions per unit of energy than conventional gas, but up to 15% higher under some conditions.[292]
- An MIT-lead study suggested that the Howarth results used data that was not representative of typical shale gas wells. Their results suggest that well-completion emissions make up 2–3% of all emissions.[293]
- In a response to the critiques, and particularly in response to Cathles et al., Howarth et al. later[294] defended the use of the units of heat energy in the 2011 paper, because only 30% of gas is used for electricity currently, and the use of the 20–year time frame, stating that short term emissions are critical to climate system tipping points.
- A recent study found that shale gas life cycle emissions are 6% lower than conventional natural gas, 23% lower than gasoline, and 33% lower than coal, but with significant

[287] J.D. Hughes, *Lifecycle Greenhouse Gas emissions from shale gas compared to coal: analysis of two conflicting studies* (Post Carbon Institute, 2011). http://www.postcarbon.org/report/390308-report-life-cycle-greenhouse-gas-emissions#

[288] Cathles et al., "A commentary on "The greenhouse-gas footprint of natural gas in shale formations" by R.W. Howarth, R. Santoro, and Anthony Ingraffea," *Climatic Change,* 113 no. 2 (2012). DOI 10.1007/s10584-011-0333-0

[289] J.Wang, D. Ryan, E. J. Anthony, "Reducing the greenhouse gas footprint of shale gas," *Energy Policy* 39 (2011).

[290] M. Jiang, et al., "Life cycle greenhouse gas emissions of Marcellus shale gas," *Environmental Research Letters* 6 (2011). doi:10.1088/1748-9326/6/3/034014

[291] U.S. EPA, *Inventory of U.S. greenhouse gas emissions and sinks: 1990 – 2009.*

[292] T. Stephson, J.E. Valle, X.R Palou, "Modeling the Relative GHG Emissions of Conventional and Shale Gas Production," *Environmental Science and Technology*. 45 (2011).

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overlap between shale and conventional gas so that it is not clear whether there is any significant difference.[295]

- Another recent report by the International Energy Agency also concluded that upstream shale gas emissions are higher than conventional gas, because of venting and flaring as well as the extra energy input required for drilling and pressuring and transporting fluid.[296]

Related to this debate is ongoing discussion over the most appropriate global warming potential (GWP) value used for methane, which allows comparison of different types of GHGs based on their climate change impact. The most recent Intergovernmental Panel on Climate Change report uses GWP values methane for different time frames (GWP of 72 for 20-year, GWP of 25 for 100-year and GWP of 7.6 for 500-year).[297] This distribution reflects the short atmospheric life of methane. In the original Howarth et al. paper, the GWP values were higher than the IPCC values (GWP of 105 for 20-year and 33 for 100-year) based on a newer publication that suggests that methane interacts with aerosols in the atmosphere to create a stronger warming impact.[298] Non-peer reviewed analyses of the Howarth et al. paper also critiqued the use of the 20-year time frame, but also raised questions on what time frame is the most appropriate for assessing global warming potentials.[299,300]

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