Introduction

Shale rocks containing hydrocarbons can be found in most sedimentary basins across Canada, with the largest concentration lying within the Western Canada Sedimentary Basin. As of August 2013, the Geological Survey of Canada estimated that Canada has approximately 4,995 trillion cubic feet ("Tcf") of shale gas in place. Estimates of recoverable shale gas in Canada differ somewhat, as the U.S. Energy Information Administration estimates that 573 Tcf of Canadian shale gas is technically recoverable, giving Canada the world’s fifth largest reserves of recoverable shale gas. The Canadian Society of Unconventional Resources estimates that between 343 Tcf and 819 Tcf are economically recoverable and marketable.¹ Although there are shale gas reserves in many jurisdictions in Canada, Alberta and British Columbia are currently the two largest producers, with British Columbia producing substantially more than Alberta.² This article provides an overview of the regulatory regime for the exploration and production of shale gas in Alberta and British Columbia, as well as some emerging issues that may affect project development and operations.

Systemic Considerations

(i) The Process

Hydraulic fracturing ("fracking") uses the injection of fluids, chemicals and proppant (typically sand) underground to fracture shale rocks.³ Fracking causes the release of natural gas which would otherwise be uneconomical, if not impossible, to produce. The process has been utilized commercially in Canada for approximately 60 years, although recent innovations in horizontal drilling and multi-stage fracturing have improved efficiency dramatically, which has lead to an increase in shale gas production in Canada.
(ii) Acquisition of Natural Gas Rights

In Canada, a project proponent must first acquire a lease, licence or permit from the owner of the surface and/or mineral rights before it will be permitted to drill for natural gas.

In Alberta, the Province owns the mineral rights to 81% of the province’s petroleum and natural gas resources. The remaining 19% are owned by private owners, or by the federal government on behalf of First Nations or located in national parks. If a company wants to explore for and produce natural gas, it must obtain the mineral rights for that natural gas. A natural gas lease or licence gives the company the legal right to drill for and recover any natural gas underlying the land covered by the lease or licence. In return for the company’s right to develop natural gas resources, payments flow back to the province or the private landowner in the form of the initial lease consideration, and rental and royalty payments. Further, private owners of mineral rights are taxed by the province on the production of natural gas from their holdings.

Alberta Energy (a Ministry of the Government of Alberta) issues leases and licences through an auction process. At the end of a sale period for a parcel of land, the bidder with the highest bid will be awarded the lease or licence for the mineral rights. Project proponents may also submit requests to Alberta Energy to include the minerals rights for certain lands in a sale. In British Columbia the Province manages its land rights through a tenure system that is similar to Alberta’s. Like Alberta, most of the natural gas rights are owned by the Province, with a small percentage held by the federal government and private owners. The Ministry of Energy and Mines, Titles Division (the "Ministry") manages provincially-owned natural gas rights in British Columbia. Tenure agreements with the Province allow natural gas companies to explore, develop, produce and market natural gas. These agreements give rights to specific areas, and may include rights to all depths, or may be restricted to certain geological formations. Much like Alberta, natural gas rights can be acquired by bidding in monthly land sales. In both British Columbia and Alberta, freehold mineral rights are negotiated directly with the mineral rights owner.

Subsurface leases on First Nations lands can be obtained through a public tender process, responding to a proposal process, or direct negotiations with the First Nation. All leases on reserve lands must be approved by both the First Nation and Indian Oil and Gas Canada, an agency of the Government of Canada that manages and regulates petroleum and natural gas on First Nations reserve lands.

In addition to obtaining mineral rights, to access the natural gas it is necessary to enter
upon the surface of either privately owned or Crown occupied land. In Alberta and British Columbia, a project proponent is not permitted to enter onto land to conduct operations without having first obtained the consent of the owner and the occupant of the surface, or having become entitled to right of entry by reason of an Order of the applicable Surface Rights Board in that province. If the project proponent is unable to negotiate a surface lease with the owner of the land, it may apply to the Surface Rights Board for relief. The Surface Rights Boards of Alberta and British Columbia have authority to grant rights of entry, and assist landowners and developers to resolve disputes about rights of entry, related compensation, negotiation and recovery of rental payments, damages and reviews of compliance or past decisions.9

To gain entry onto Crown occupied lands in Alberta, a project proponent must negotiate rights of entry with the Crown which is facilitated through the Department of Environment and Sustainable Resource Development ("ESRD"). The ESRD “negotiates access restrictions with other Crown agencies and departments through integrated resource management principles and operational planning exercises, advocating and negotiating for reasonable access on the behalf of companies leasing mineral rights, and on behalf of all Albertans who benefit from resource extraction”.10 Rights of entry are exercised as addendums to tenure agreements. In British Columbia, a project proponent which is licensed by the Province and which holds either a Mines Act permit or, for larger projects, an Environmental Assessment Act certificate, may claim tenures from the Crown. These tenures are maintained by recording the interest in an online registry and paying a fee. Once a project proponent holds a mineral claim they may enter Crown land to develop or produce minerals.11

To gain surface access to First Nations lands, a project proponent must apply for access, and both the First Nation and Indian Oil and Gas Canada must approve surface leases and rights of way.12

**Shale Gas Regulation**

Shale gas exploration and production in Alberta and British Columbia is governed by numerous statutes, regulations and policies. Currently there are no statutes specifically tailored to shale gas operations. Shale gas is largely regulated the same way as other natural gas production, which is through the enactment of regulations and rules by the primary regulatory agencies. The statutes and regulations that govern shale gas development in Canada are primarily provincial, with federal statutory and regulatory jurisdiction only applying in particular circumstances, such as with respect to First Nations
reserve lands, or interprovincial pipelines. Most major oil and gas companies are also members of the Canadian Association of Petroleum Producers ("CAPP"). CAPP has published voluntary guiding principles and operating practices by which members strive to abide while operating in Canada.

(i) Alberta

In Alberta, shale gas operations are primarily regulated by the Alberta Energy Regulator ("AER"). The AER ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources over their entire life cycle. This includes allocating and conserving water resources, managing public land and protecting the environment, while providing economic benefits for all Albertans. The AER primarily regulates and monitors shale gas activity through the Oil and Gas Conservation Act, RSA 2000, c O-6 and its accompanying regulation, the Oil and Gas Conservation Rules, Alta Reg 151/1971. However, at any given time during the life cycle of a project, the proponent will have obligations under other provincial and federal statutes and regulations, and interactions with other government regulators and agencies, such as Indian Oil and Gas Canada, the ESRD, or the Surface Rights Board.

Depending on the proposed activity, a project proponent may be required to notify local residents, First Nations and Métis, occupants, other affected companies or local authorities so those parties can fully understand the potential impact of the project. The requirements for such notification may be set out in the enactment under which the application is being made, or the various rules of practice, application guides and manuals, AER Directives, AER information letters or other written communications of the AER. To obtain a licence to drill for natural gas, the company must submit an application to the AER. The application must be in writing and include, at a minimum, the applicant’s contact information, a description of what is being applied for, a statement of facts relevant to the application and other useful information in support of the application. An application may require additional content as set out in specific energy resource enactments. Once the AER receives an application, it provides notice of the application through its website. At this point, stakeholders who believe they are directly and adversely affected typically have 30 days to file statements of concern. Applicants are expected to use the statements of concern to identify and resolve any issues. The decision to grant or deny a licence is made either at a staff level or after a regulatory hearing. Due to the volume of applications, most decisions are made at the staff level. AER staff consider statements of concern and the criteria set out in the applicable enactments. Alternative dispute resolution ("ADR") can also be employed by the AER at
any stage of the process. At the pre-application stage, project proponents can ask the AER to provide ADR to help resolve issues that emerge. Additionally, the AER has the authority to require parties to engage in ADR and may also determine which parties are to participate in the ADR process. When it is deemed appropriate, the AER may hold a hearing before making a decision; hearings can be written, electronic, oral or a combination of these forms. The AER will then notify the applicant and any person who filed a statement of concern of their decision. These decisions are published on the AER’s website.

Unless a hearing was conducted or an agreement was reached under ADR, an appeal mechanism is available for AER decisions. A request for an appeal must be submitted by an “eligible person”. An eligible person is (i) any person who is directly and adversely affected by the decision of the AER under an energy resource enactment, (ii) any person who is permitted under the specified enactments to file a notice of appeal under those enactments, or (iii) any other person described in the regulations. Additionally, any person can request to participate in the hearing of an appeal by filing such a request, though the AER has authority to deny these requests. Generally, the time period to request an appeal on an application decision is 30 days. Furthermore, with prior leave, all decisions of the AER can be appealed to the Alberta Court of Appeal on questions of law or jurisdiction.

The AER plays an ongoing role in monitoring and ensuring compliance with energy resource enactments. The AER issues directives, manuals and information letters that set forth both requirements and recommended best practices for shale gas and all other hydrocarbon production in Alberta. One of the directives that impacts shale gas operations is AER Directive 059: Well Drilling and Completion Data Filing Requirements which, among other things, requires producers to keep records of all operations on a well, disclose well data and activity, and disclose the composition of fracture fluid and water source data. Another key directive is Directive 083: Hydraulic Fracturing – Subsurface Integrity, which sets forth the requirements for operators to prevent loss of well integrity, in order to avoid adverse affects from fracking on aquifers, other wells and the surface.

The AER has developed a risk-based inspection process that is supplemented by a project proponent’s duty to self-disclose. If it is determined that a project proponent is not in compliance with all applicable requirements, the AER can investigate and use enforcement tools, including administrative penalties, stop orders, enforcement orders, suspension or cancellation of licences, and prosecutions.
The AER also implements a liability management program under Directive 006: Licence Liability Rating (LLR) Program and Licence Transfer Process. The purpose of the LLR program is to prevent the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline from being borne by Albertans. A project proponent’s LLR is determined by comparing its deemed assets to its deemed liabilities. If a project proponent’s liabilities exceed its assets, plus any previously provided security deposits, it will have a LLR ratio below 1.0, and will be required to provide the AER with a security deposit to cover the cost of the outstanding remediation and reclamation obligations.

When a project proponent’s licence expires, or wells are no longer commercially viable, these wells must be abandoned. Before doing so, the project proponent must inform all affected landowners, test the well to ensure that it will not pose any risk to the public or the environment, and, if any issues are found during testing, make necessary modifications to correct these issues. In addition to abandonment, the proponent must return the land as close as possible to its original state. This is known as reclamation and is considered complete only when the habitat around the abandoned well returns to its original form, and the abandoned well cannot be seen from the surface.

Alberta also employs a scheme for deep rights reversion ("DRR") and shallow rights reversion ("SRR"). Under the DRR scheme, the natural gas rights in the zone below the deepest productive zone are severed and revert to the Crown at the time of lease continuation. Under the SRR scheme, the natural gas rights in the zone above the top of the shallowest productive zone are severed and revert to the Crown at the time of lease continuation. The rationale for these schemes is to encourage production on provincial lands and increase Crown royalty revenues. In 2013, Alberta announced it was indefinitely suspending serving SRR notices for agreements issued before Jan. 1, 2009.

The royalty regime is a critical factor in natural gas regulation. A principle of Alberta’s regime is to retain a share of production as a royalty to benefit Albertans. The royalty rate in Alberta is based on a formula and differs depending on which mineral is being produced, the current market price and well productivity. Unique to shale gas production is the Shale Gas New Well Royalty Rate. In areas which the AER has designated as shale gas producing, any new wells that began producing after May 1, 2010 are subject to a 5% royalty rate for the first 36 months of production. These new wells are not subject to any volume cap, but the rate does not apply to shut-in wells re-entering production. Re-entry, reactivated, lengthened and deepened well events may qualify for the Shale Gas New Well Royalty Rate provided there was no prior production from the well. Following 36 months of production, new shale gas wells are subject to the same royalty formula as conventional gas and previously producing wells. The Alberta conventional gas royalty rate
varies between 5% and 36% depending on commodity price and the quantity produced.  

(ii) British Columbia

In British Columbia, shale gas operations are primarily regulated by the Oil and Gas Commission ("OGC"). The OGC is a Crown (provincially-owned) corporation responsible for regulating the exploration, development, production and pipeline transportation of oil and gas in British Columbia. The OGC’s roles include reviewing and assessing applications for industry activity, consulting with First Nations, ensuring that industry complies with provincial legislation and cooperating with partner agencies. Responsibility extends from exploration and development through to operation and decommissioning. The OGC primarily regulates and monitors shale gas activity through the Oil and Gas Activities Act, SBC 2008, c 36, and its accompanying regulations, the Environmental Protection and Management Regulation, B.C. Reg 200/2010, Oil and Gas Activities Act General Regulation, B.C. Reg 274/2010, and Drilling and Production Regulation, B.C. Reg 147/2014. Similar to Alberta, a project proponent will have obligations under other provincial and federal statutes and regulations, and interactions with other government regulators and agencies outside the OGC.

A project proponent must go through a multi-step process to be permitted to drill for shale gas. Before submitting an application to the OGC for a permit, the project proponent must notify the owner of the land on which it intends to carry out natural gas activities. Affected parties may make written submissions to the OGC concerning applications. An application for a permit must contain a description of the proposed site, the information, plans, application form and records required by the OGC, a written report detailing the results of consultation and notification with landowners, the prescribed information and records, and a security which may be required by the OGC. If the applicant meets the requirements of the OGC, taking into consideration the government’s environmental objectives, a permit will be issued. If a permit is issued, the OGC must provide notice to the landowner of the land upon which shale gas activities will take place. A notice sent to the landowner must state it has a right to appeal the decision. A permit holder must not begin activity on the landowner’s land until 15 days have elapsed from the day the permit was issued, unless the landowner consents in writing.

The OGC is also charged with ongoing monitoring and compliance review of natural gas activities through directives, information bulletins, information letters and safety advisories. One important directive is Directive 2011-03: First Nations Consultation on Short Term Use of Water Applications, which states that the OGC will consult applicable First Nations
on all applications for short term water use that may affect their treaty or Aboriginal rights. Another key document is Information Letter #OGC 09-07: Storage of Fluid Returns from Hydraulic Fracturing Operations, which details the requirements for the containment, storage and disposal of returned fracture fluids.

Additionally, if the OGC is of the opinion that a project proponent has failed to comply with any energy resource enactments, or the permit which it was granted, it may issue an Order that will specify the action to be taken, stopped or modified. An Order may also be issued if it is necessary to mitigate risk to public safety, protect the environment or promote the conservation of petroleum and natural gas resources. The OGC may also enter land or premises, at any reasonable time, for the purposes of conducting inspections or audits. The OGC enforces compliance with energy resource enactments through orders, administrative penalties and suspension or cancellation of permits. The OGC instituted a liability management rating ("LRM") which is almost identical to the LLR system employed by Alberta.

Before abandonment of a well in British Columbia, an abandonment notification and report must be submitted to the OGC. Abandonments are to be conducted under the same procedure as employed by Alberta. Upon the completion of shale gas activity, project proponents have the obligation to restore the land to an equivalent condition and capability. The reclamation requirements are intended to provide the flexibility to respond to differing site characteristics and soils.

British Columbia employs a rights reversion scheme known as zone specific retention ("ZSR"). Under the ZSR scheme, any zone that is not producing hydrocarbons at the time of lease continuation reverts to the Crown. This is distinguishable from the Alberta schemes which only revert the zones above or below the producing zones. This ZSR scheme appears to be more favourable to Crown lessees than the Alberta schemes, as a project proponent only needs to show the presence of oil or gas to continue the Crown lease. It should also be noted that the ZSR scheme only applies to leases issued after March 29, 2007.

The shale gas royalty regime depends on whether gas is conservation or non-conservation. Conservation gas is gas produced from an oil well where the marketable gas is conserved. The royalty rate on conservation gas is 8% when the reference price is less than or equal to $50 per 10^3m^3, but increases by way of a variable formula when the reference price is above $50 per 10^3m^3. Non-conservation gas is gas which is produced absent of oil. The royalty rate on non-conservation gas varies, but is determined by the date the well was drilled and the market price for natural gas.
Emerging Issues

(i) Aboriginal Rights and Tsilhqot’in

Fracking, and other oil and gas activities, may come in conflict with the treaty and Aboriginal rights of First Nations affected by the extraction of natural gas. In Canada, Aboriginal title to land flows from its occupation, in the sense of regular and exclusive use of the land. The test for Aboriginal title requires the group asserting title to satisfy the following criteria:

(1) the land must have been occupied before sovereignty;

(2) the present occupation is relied on as proof of occupation pre-sovereignty, and there must be continuity between present and pre-sovereignty occupation; and

(3) at sovereignty, that occupation must have been exclusive.

Aboriginal title confers the right to use and control of the land, and to reap the benefits flowing from it. This right is limited by the caveat that uses must be consistent with the group nature of the interest and enjoyment of the land by future generations. Where title is asserted, but has not yet been established, the Crown has a duty to consult with the group asserting title and, if appropriate, accommodate its interests. Once title is established, incursions onto the land are only permitted with the consent of the group, or if it is justified by a compelling and substantial public purpose which is not inconsistent with the Crown’s fiduciary duty to the Aboriginal group.

The recent Supreme Court of Canada decision in Tsilhqot’in Nation v. British Columbia makes it easier for First Nations in areas not covered by treaties to determine and claim Aboriginal title, and the standard for consultation and accommodation has been increased. However, governments still have substantial authority to determine the course of natural resource development. This is based on the exception that the Supreme Court carved out which allows for projects to proceed if they are justified by a compelling and substantial public purpose which is not inconsistent with the Crown’s fiduciary duty. This decision will have a greater effect on shale gas projects in British Columbia than those in Alberta, as most of the land containing shale gas in Alberta has been surrendered through treaties.

(ii) Seismic Activity

Seismic activity has been linked to fracking and the injection of wastewater underground following fracking activity. The Alberta Geological Survey, which is part of the AER,
monitors seismic activity in the Province. A series of recent seismic events in December 2014 and January 2015 near Fox Creek, Alberta, prompted the AER to issue Subsurface Order No. 2 on Feb. 19, 2015, relating to fracking operations in that area. The order requires licensees to “assess the potential for induced seismicity caused by or resulting from hydraulic fracturing operations and adopt, and be immediately prepared to implement, a response plan to address potential seismic events … follow a traffic light process with staged thresholds … immediately report to the AER seismic events of 2.0 [local magnitude] or greater and invoke their response plan.”

Further, “the order requires operators to cease hydraulic fracturing operations altogether if a seismic event of 4.0 [local magnitude] or greater is detected in the vicinity of their operations. In these circumstances, licensees will not be permitted to resume operations without AER consent.”

(iii) Industry Response

Public scrutiny of the environmental impacts of oil and gas activities has been increasing. The public is demanding more disclosure of the operations and policies of project proponents at every stage of a project’s life cycle.

In 2012, Environment Canada requested that the Council of Canadian Academies provide a report on the “state of knowledge of potential environmental impacts from exploration, extraction, development of Canada’s shale gas resources” and the “state of knowledge of associated mitigation options.” The 2014 report produced by the Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction notes that while shale gas development has gained momentum in Alberta and British Columbia, several other provinces (Québec, New Brunswick, and Nova Scotia) are still exploring its potential development. Canada, in comparison with the United States, has taken a considerably slower approach to shale gas development, providing Canadian jurisdictions the opportunity to properly explore industry practices and regulatory management.

The key findings of the report are that, while technologies and techniques are generally well understood, more research is required with respect to potential environmental impacts of fracking, the data about which is neither sufficient nor conclusive. Further, the report highlights the importance of accounting for regional differences in ecosystems and geologies when determining appropriate management and regulation of shale gas development.

In response to heightened public concern over the practice of fracking and natural gas
exploration in general, CAPP published the Guiding Principles for Hydraulic Fracturing,\textsuperscript{72} which contain five statements which members of CAPP strive to abide by in their exploration and development of natural gas. CAPP also established industry-wide Hydraulic Fracturing Operating Practices,\textsuperscript{73} which outline best practices that project proponents should strive to meet during the project life cycle.

\textbf{Conclusion}

The regulation of shale gas in Alberta and British Columbia can be understandably confusing, but fortunately, their regulatory regimes are markedly similar. From the initial communications with potentially affected landowners to abandonment and reclamation, the regimes are clear and consistent. If project proponents abide by the regulations and take care to act as stewards of the environment while doing so, the two regimes can assist with the exploration and development of petroleum and natural gas resources, including the vast shale gas resources in those provinces.

\textsuperscript{3} Ibid at 4.
\textsuperscript{5} Ibid.
\textsuperscript{6} Ibid.
\textsuperscript{8} Indian Oil and Gas Canada, “Issuance and Administration of Subsurface Agreements”, online.
\textsuperscript{9} The Alberta Surface Rights Board, “About the Alberta Surface Rights Board”, online: The Alberta Surface Rights Board.
\textsuperscript{10} Alberta Energy, “What is Resource Land Access?”, online.
\textsuperscript{11} Ministry of Energy, Mines and Natural Gas, Minerals and Private Land in British Columbia: Factsheet (May 7, 2008), online.
\textsuperscript{12} Indian Oil and Gas Canada, “Issuance and Administration of Surface
Agreements”, online.

15 Ibid at 9 - 10.
16 Ibid at 11.
17 Ibid at 12.
18 Ibid at 13.
19 Ibid at 14.
20 Ibid at 14.
21 Ibid at 14.
22 Ibid at 14.
23 Ibid at 15.
24 Ibid at 20.
25 Ibid at 18.
26 Ibid at 18.
27 Ibid at 18.
28 Ibid at 20.
29 See fracfocus.ca.
30 Ibid at 29 - 30.
32 Ibid at 3.
33 Ibid at 3.
37 Ibid at para 1.
38 Ibid at para 1.
39 June Warren-Nickle's Energy Group, “Alberta shelving shallow rights reversion plans”, Oil & Gas Enquirer (27 May 2013) online: Oil & Gas Enquirer.
40 Alberta Department of Energy, Oil and Gas Fiscal Regimes: Western Canadian Province and Territories (June 2011), online: energy.alberta.ca at 23.
41 Alberta Energy, “Shale Gas New Well Royalty Rate FAQ”, online.

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Ibid at para 2.

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Canadian Association of Petroleum Producers, Guiding Principles for Hydraulic Fracturing, December 2012.

Canadian Association of Petroleum Producers, Hydraulic Fracturing Operating