

Shale Gas in New Brunswick: Promise, Threat, or Opportunity?

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Abstract

A petroleum industry has existed in New Brunswick for over 150 years but recent exploration for shale gas has unleashed an unprecedented wave of protest and opposition. This opposition is an international phenomenon that has followed the relatively new shale gas extraction industry from its origins in Texas, across North America and Europe. On the one hand, the extraction of natural gas from shale has increased reserves to the point where North America could become self-sufficient; on the other hand, opponents point to completely new hazards associated with this form of gas production. New Brunswick has the opportunity to devise a regulatory (and enforcement) regime that could minimize risk and maximize the benefits of a shale gas extraction industry. Public engagement in establishing this regime is essential, but the details, as this essay will illustrate, must be based on a rational and factual assessment of risk.

Résumé

L'industrie pétrolière existe au Nouveau-Brunswick depuis plus de 150 ans, mais la récente exploration du gaz de schiste a déchaîné une vague de protestation et d'opposition sans précédent. Cette opposition est un phénomène international qui a poursuivi l'industrie relativement nouvelle de l'extraction du gaz de schiste, depuis son origine au Texas, dans toute l'Amérique du Nord et jusqu'en Europe. D'un côté, l'extraction du gaz naturel à partir du schiste a accru les réserves au point que l'Amérique du Nord pourrait devenir autosuffisante; d'autre part, les opposants dénoncent des risques entièrement nouveaux liés à cette forme de production de gaz. Le Nouveau-Brunswick a l'occasion de mettre au point un régime de réglementation (et de mise en œuvre) qui pourrait réduire le risque et maximiser les avantages d'une industrie de l'extraction du gaz de schiste. La participation du public pour mettre ce régime en place est essentielle, mais les détails, comme cet article le démontrera, doivent être fondés sur une évaluation rationnelle et factuelle des risques.

Correction: There is a problem with citation number 4 in this article, brought to my attention after the issue went to press. The citation is to a podcast of a radio program, and the various quotes I made in the text referred to the entire broadcast. Unfortunately, the current content of the podcast is an edited version of the segment of the program that is an interview with myself and Jim Emberger, so the citation gives the impression I am attributing all the comments to him. Mr. Emberger, was not the source for any of these comments. The error, though unintentional, was mine. I take full responsibility and apologize for any misrepresentation that may have arisen.

The petroleum industry is no stranger in New Brunswick. The mining of oil shale and albertite (hard bitumen) commenced in the early 1850s around Albert Mines in Albert County. Crude oil was discovered shortly afterwards with a briefly producing well drilled near Dover (Westmorland County) in the 1860s and the first long-term producing oil and gas field discovered at Stoney Creek, south of Moncton. It produced from 1910 until 1991 (Hillsborough being the first town in Atlantic Canada to have piped natural gas) and was reopened in 2006 using more modern extraction techniques. Exploration has been continuous, if sporadic, for a century and a half, with the largest recent discovery being the McCully gas field near Sussex that began producing in 2003.¹

The oil shale is the key. This rock was laid down as mud in a lake some 350 million years ago during the Carboniferous period.² The mud was rich in organic detritus: the remains of planktonic animals and plants. Burial and heating gradually converted the mud to shale and the organic detritus to kerogen, a brown waxy substance. This is the source rock for most New Brunswick's oil and gas (similar kerogen-bearing shales exist in older rocks around Campbelltown and Dalhousie formed in a shallow sea). In *conventional* oil and gas—the crude oil and gas that flow out of a well—this source rock has been cooked to between 60 and 120°C and the kerogen has broken down to yield methane, light oils (gasoline and diesel equivalents), or heavy oils (more like heating oil). What happens next relies on two important properties of sedimentary rocks like shale and sandstone. These rocks contain open spaces or pores, and these pores can be interlinked between grains or by fractures (or both). The pore spaces constitute the *porosity*, or the ability of a solid rock to store fluids (water, oil or gas), while the communication between these pores is the *permeability*, or the ability of fluids to flow through the solid rock. Conventional oil and gas flow from the source rock into layers with the right combination of porosity and permeability (reservoirs) that are sealed with other layers with no or very little permeability, creating traps. Exploration for conventional oil and gas tries to locate traps and reservoirs that may contain oil and gas.

Unconventional oil and gas are produced by exploiting the source rocks directly: ironically, the oil shale and albertite mines in New Brunswick, North America's first petroleum industry, were *unconventional* in the modern sense. In fact, until the 1880s the mining of oil shale was fairly extensive, both here and in Europe (especially Scotland). The New Brunswick industry could not compete with crude oil and gas that flowed out of wells, and declined after the 1880s. The last oil shale mine (near Rosevale) closed in the 1920s. This mining left all the usual legacy of the industry: large spoil heaps draining contaminated water and large scars on the landscape. At Albert Mines the spoil heaps are relatively benign and the extractive scars are almost completely overgrown. In Scotland the huge spoil piles, known as *binges*, drain acidic water laced with arsenic and a cocktail of toxic heavy metals. Eighty years after the oil shale industry died they remain a problem.

The game changer in the extraction of oil and gas directly from source rocks happened in the 1980s. First, new techniques for improving the efficiency of conventional oil and gas extraction from permeable reservoirs became routine. Second, a new drilling technique, known as *directional drilling*, permitted a well to be turned underground from vertical to horizontal so that several traps could be tapped from one well site (up to thirty holes from one well site if conditions are suitable).

Many conventional oil and gas reservoir rocks have low permeability—they are *tight*—with the result that oil and gas flow slowly, and a high percentage of such deposits simply cannot be extracted. Even in a reservoir that is not tight, up to 60 percent of the oil present may not flow. Enhanced recovery techniques have included methods such as fracturing to increase permeability of the reservoir rocks. In the late 1800s and early 1900s this typically involved using explosives (generally nitroglycerine) down the well, but in the 1940s *hydraulic fracturing* (also known as *hydrofracturing*, *fracking*, or *fracking*) was developed. In hydrofracturing a steel pipe is inserted into the reservoir rocks, then pressurized with water until the pressure exceeds that in the surrounding rocks. The pipe is perforated using explosives and the excess pressure causes the surrounding rock to fracture creating new permeability (each explosive charge being comparable to a shotgun shell).

Directional drilling combined with hydrofracturing was first attempted on the Barnett Shale in Texas (1982) and commercial quantities of natural gas flowed. This was at a time when the U.S. was importing 40 percent of the oil and gas it needed, and that figure looked set to rise inexorably along with the issue of security of supply becoming more and more critical. By 2000, potential shale gas resources amenable to the extraction techniques applied to the Barnett Shale had been identified all across North America, and in short order a shale gas industry began exploiting shale layers in Louisiana, Arkansas, Oklahoma, Mississippi, and Alabama, then turned north to Pennsylvania, New York State, and Ohio.³ Crucial to what followed was the Act signed into law by President George W. Bush in 2005 exempting exploration and production companies from federal environmental regulation and the terms of the Clean Water Act. With the federal Environmental Protection Agency out of the picture, regulating the industry fell to state agencies that, in the interests of “small government,” had been systematically gutted of personnel and resources since the Reagan years. The result was predictable, with many companies entering the fray with little experience of deep drilling and hydrofracturing and the temptation to cut corners to maximize profits. Subsequent problems prompted New York state and Ohio to impose moratoria on exploration and development.

The oil shale in New Brunswick has inevitably attracted the attention of companies wanting to exploit shale gas (and in the process realize the dream of North American self-sufficiency). As this interest has grown so has a vocal anti-shale gas lobby, part of a North American and European movement expressing public lack of trust in government and industry, and utilizing the viral nature of the Internet and social media to pass on a message that, to misquote Douglas Adams, is often “at best apocryphal and at worst wildly inaccurate.” This vocal lobby has been picked up by the alternative media (not renowned for exercising critical thinking) who pass on and amplify the message.⁴ The popularity of such quasi-documentary films as *Gasland*, and a more recent local effort, *Be...without Water*, tap into this same (and very genuine) fear and mistrust.⁵ In New Brunswick this fear focuses on the dangers posed by shale gas extraction to groundwater supplies—understandable given that most New Brunswickers outside Moncton and Saint John rely on wells for their drinking water. A more rational and factual discussion of the issue can be found in Chris Mooney’s article.⁶

So what is groundwater, and how does shale gas exploitation using hydrofracturing threaten it?⁷ Groundwater fills pores and fractures in soil and the deeper bedrock. It is mainly surface water that has percolated down into the substrate and then channeled through porous and permeable layers (in a similar fashion to oil and gas). It comes back to the surface through springs and is recharged by more surface seepage. This cycle from recharge to discharge can take a matter of days or thousands of years. Not all groundwater is potable; generally the longer the cycle takes the saltier the water will be, and local peculiarities of geology can render water unusable (in New Brunswick natural high concentrations of manganese and arsenic can be an issue). Well water usually comes from groundwater in reservoirs (aquifers) within 50–150 metres of the surface. These shallow aquifers with a rapid recharge-discharge cycle are particularly susceptible to contamination, and these problems are well documented. Of particular concern are:

1. agricultural runoff containing manure effluent, fertilizer, and pesticide residues;
2. runoff from winter road treatment;
3. leaking underground or surface fuel tanks;
4. leakage of toxic liquids from landfills;
5. over-pumping (extraction of water exceeding the rate of recharge); and
6. leaking of sewage pipes and septic systems.

To this list can be added the fact that any natural resource extraction (gravel pits, quarries, mines, and water extraction) or engineering project (new roads, pipelines) have the potential to interfere with shallow aquifers. The anti-shale gas lobby has at least drawn public attention to the importance of groundwater in New Brunswick. So what are the risks associated with oil and gas, and especially shale gas extraction?

1. Can methane leak into aquifers and does hydrofracturing increase this risk?

Gasland includes spectacular footage of residents of western Pennsylvania and Colorado igniting the water flowing from their faucets and bathtubs: the culprit being methane in their well water. What director Josh Fox deliberately omitted from *Gasland* was any mention that residents in both areas were able to do this long before the petroleum industry appeared. In Pennsylvania, where the bedrock is rich in coal, ignitable wells have been known for two hundred years, and in Colorado this phenomenon attracted exploration in the first place. Similar problems have been noted in New Brunswick since first European settlement where the oil shale lies in the immediate bedrock (around Albert Mines, Hillsborough, Dover, Gautreau, and south of Sussex). Where methane seeps into wells, the danger of fire, explosion, and asphyxiation is obvious, and the solution has long been known: the affected wells must be vented, and water held in a ventilated tank until the gas disperses. Methane has no toxic effects on the drinking water. All this natural seepage is a consequence of natural permeability: open fractures in shallow bedrock.

Natural permeability through fractures generally decreases with depth. This is the result of the weight of overlying rock closing off fractures. As common rocks weigh between 2.7 and 3.0 tons per cubic metre, the pressure increases between 2.7 and 3.0 tons per square metre with each metre of depth. This creates a natural permeability barrier between 200 and 500 metres below the surface, and this barrier generally separates shallow potable aquifers from deeper briny aquifers. This natural barrier is not perfect, but clearly every attempt should be made to preserve its integrity in order to minimize the risk of contamination of shallow aquifers. Fractures created underground by hydrofracturing typically run

for tens of metres (100–150 metres is usually the maximum) and rarely pass from one rock layer to another because of contrasts in physical properties between adjacent layers (some rocks fracture easily, other will not fracture at all).

The growth of induced fractures can be monitored using microseismic sensors. Any fracturing of rock generates seismic waves (mini-earthquakes) and microseismic monitors (highly sensitive geophones) placed in adjacent drill holes can locate them in three dimensions and in real time. Some jurisdictions, such as North Dakota and British Columbia, have regulations that require microseismic monitoring of hydrofracturing operations and have placed a minimum depth limit on all hydrofracturing (500 and 800 metres minimum depths, respectively). Should fractures show signs of migrating toward shallow aquifers, the well must be abandoned and sealed. The trial shale gas well at Elgin in New Brunswick was also the subject of microseismic monitoring.

The methane leaks in west Pennsylvania prompted a major study at Duke University,⁸ which concluded that the methane source was deep bedrock, and leaking wells were the problem. No leaks could be attributed to the hydrofracturing process itself. Leaking wells have been a problem for the oil and gas industry since its earliest days in the 1870s, and considerable research and innovation has addressed this problem (it being in no one's interest to lose oil or gas by leakage). Well-casing addresses this issue.

An initial well with a wide bore (30–40 centimetres) is sunk between a few hundred metres and a kilometre down. This is lined with a steel pipe, and the gap between the pipe and bedrock is cased with cement. This serves to seal the hole and anchor the pipe to the bedrock as part of the blowout prevention system (recall that fluids encountered two kilometres down will have pressures around 5000–6000 tons per square metre). A second hole of narrower bore is sunk through the first pipe, lined with another steel pipe, and another layer of cement casing is inserted. The final hole, with a bore of 25 cm, runs through the other two, and it is also cased with cement. The whole assembly is then pressurized to test the seal. Industry best practice determines the best grades of cement, steel pipe, and depth to which casing should be carried out to prevent leakage. Most jurisdictions in Canada (including New Brunswick) include this in regulations. Both best-practice codes and regulations are subject to continual review and improvement.

Naturally occurring faults (large and deep natural fractures in bedrock) and old abandoned drill holes can also threaten the integrity of the natural barrier. One especially nasty gas blowout in Pennsylvania occurred when drillers encountered abandoned underground coal workings. Faults are easily identified during routine geological surveying (including seismic exploration), and New Brunswick maintains comprehensive records of the location of old drill holes and mine workings. If necessary, old drill holes can be sealed with cement, and faults can also be avoided by the establishment of safety setback zones where no hydrofracturing is permitted.

2. What about the fluids used in hydrofracturing?

When an oil or gas well is drilled, water is employed to cool and lubricate the drill head as it cuts through rock. This same water circulates through the hole and removes rock debris. Chemicals are added to the water to improve its cooling and lubricating properties and to increase its density as part of the blowout prevention system. Additives are typically clay and the mineral barite (barium sulfate, chosen because of its high density and non-toxicity—it is the X-ray opaque material used in barium meals). Hydrofracturing water has many other additives. When the well is pressurized to create fractures, the water includes *propan*t, particles of coarse sand, glass, or ceramic beads, which enter the fractures and prop them open when the pressure is released, allowing gas to flow. Other chemicals condition the rock, reduce the ability of oil and gas to stick to the reservoir (detergents), prevent bacterial growth clogging the fractures (biocides), and control the acidity/alkalinity of the water and its ability to dissolve minerals in the bedrock or cause corrosion. The largest concern is the amount of water used in hydrofracturing.

i. What are the quantities of water used?

Hydrofracturing does use more water than conventional drilling, but how much depends of how much is recovered after a hydrofracturing exercise, and how much is recycled. The anti-shale gas lobby seems to be engaging in a “number of the week exercise.” Over six months I have seen figures rise from 1 million litres per well to 5 or even 10 million gallons per well. Actual figures from reliable sources are equally hard to come by. However, a reasonable rule of thumb is to calculate the volume of a well with some high-school math. A standard hole has a diameter of 25 centimetres, so 1 kilometre should have a volume around 40,000 litres. If a well were exploiting a shale layer 2 kilometres down with 2 kilometres of horizontal pipe, filling and pressurizing it should take at least 160,000 litres—perhaps twice that, depending

on how much fracturing occurs and how much water flows into the fractured rock. If the well were refractured four or five times this still amounts to less than 1,000,000 litres, much of which can be recycled.

ii. What are the chemical additives?

The chemical additives are many,⁹ but most are common household chemicals like sodium hydroxide (lye), calcium hydroxide (lime), and inert materials like xanthan gum. These are not chemicals you would want in drinking water, but neither are they persistent toxins. Biocides are of more concern, as these can include formaldehyde and glutaraldehyde (both known carcinogens). Polyacrylamide has also caused concern, not because it is toxic in itself (in Canada it is licensed for use in clarifying drinking water), but because it can break down to acrylamide, a suspect carcinogen, and teratogen (responsible for fetal deformities). Other chemical additives include synthetic oils whose exact composition is protected as a proprietary commercial secret. New Brunswick is moving toward mandatory full disclosure of these additives; other jurisdictions have moved to ban some of them. Any informed or rational discussion of risk requires these chemical additives be known—currently even regulators are not necessarily provided with details.

iii. How much of the water and its additives remain in the rock after hydrofracturing?

When the well is depressurized after hydrofracturing, the fluids flow back up the well, ahead of the gas. Rates of recovery can vary substantially: from as high as 95 percent to as low as 10 percent. If there is no seepage into shallow aquifers this should not be a problem, and if non-persistent toxic chemicals are used they will eventually be neutralized by degradation or reaction with minerals in the shale itself, or even be absorbed by minerals in the shale (such as clays). Clays represent an interesting case because when they absorb water they tend to swell, blocking off any permeability (one of the reasons some hydrofracturing does not produce enhanced flow).

iv. Can hazardous materials in the shale itself be released by hydrofracturing and brought to the surface?

The usual causes for concern here are hydrogen sulfide gas, heavy metals, arsenic, and radon gas. Hydrogen sulfide is very toxic, radon is radioactive, and heavy metals and arsenic are persistent toxins. Local geology dictates whether or not these compounds are going to be present, and the NB oil shale has been extensively analyzed for such compounds over one hundred years of study. Hydrogen sulfide has not been identified as a problem, and the oil and gas in the Stoney Creek field, and the gas at McCully, both ultimately derived from the oil shale source rock, are *sweet oil and gas* that is hydrogen-sulfide free. Radon is not a problem, as the oil shale is unusually low in uranium (the ultimate source of radon). Levels of arsenic and heavy metals are known to be low, but clearly, if the industry developed on a large scale, there would be a need for routine and rigorous monitoring.

v. How are fracking fluids stored and disposed of?

Surface spills of drilling and hydrofracturing fluids are generally more of a problem than leaking wells. As hydrofracturing uses more fluid and different additives than conventional oil and gas drilling, surface storage and disposal are a larger issue. Storage can occur in open ponds or sealed tanks while drilling and hydrofracturing are ongoing; fluids can then be transported from the site for disposal. Well sites already have to take precautions against spillage. The surface ponds and even the entire well site must have impermeable liners, and the site protected by earth berms to prevent runoff (under the terms of the provincial Oil and Gas Act and the Clean Water Act). Ponds have the advantage that water can evaporate leaving additives behind as solid waste that is easier to handle and dispose of, but ponds are more prone to overflow during heavy rain. At the experimental shale gas well at Elgin, fluids were all stored in tanks and transported to a licensed site for disposal. Should the industry develop on a large scale, disposal sites will require increased capacity.

vi. Are there alternatives to the use of water?

Water is used for hydrofracturing because as a liquid it does not compress (therefore transmits pressure very effectively), is cheap, abundant, and easy to handle. Other liquids can be employed. The gas field at McCully near Sussex is regularly hydrofractured to improve the permeability of a tight conventional reservoir, and the operating company has enjoyed considerable success using liquid propane. The advantages of this liquid are several: it does not require many of the additives used with water (especially the toxic biocides), and when it is recovered it is either flared off or fed into the gas stream (it is already a minor component of natural gas). The technology for handling liquid propane is widespread and well understood.

3. What about earthquakes?

Over the last six months Greenpeace UK has taken to calling shale gas extraction “earthquake-causing shale gas fracking,”¹⁰ and in North America this rhetoric has not lagged far behind. On a radio discussion last fall, it was reported that Oklahoma and Arkansas “had suffered more and bigger earthquakes than in all recorded history” and that the UK earthquakes were associated with a type of fault “that traditional geological surveying cannot identify.”⁴

Mining, oil and gas extraction, groundwater extraction, and the filling of hydroelectric dam headponds can all be associated with earthquakes. It would be surprising if shale gas extraction were not to be associated with them as well.

The pertinent questions are how large are such earthquakes and do they pose a threat to life and property? The UK earthquakes occurred a few kilometres from a test shale gas project in NW England and had Richter magnitudes of 2.3 and 1.5.¹¹ Such tremors pose no threat to life or property (though the comparable McAdam tremors in March 2012 were clearly disturbing). New Brunswick regularly experiences tremors in the 2.0–4.5 range,¹² as does NW England. (Incidentally, the UK tremor occurred along a fault known as the Preesall Fault, identified as such on local geology maps in the 1970s and first located during salt-mining in the 1940s.¹³) The Arkansas-Oklahoma area is a historic seismic zone¹⁴ (so is the Youngstown, Ohio, area, site of another much-hyped tremor in fall 2011). Recorded history in NB goes back to around 1800, but First Nations’ oral histories mention tremors occurring over many centuries. Induced seismic tremors need to be seen in the context of the background natural seismicity of the area, and ideally any human activity should not induce events that are larger.^{10,15}

4. Where is shale gas likely to be located?

Nearly 150 years of exploration in New Brunswick means that the geology concerned is fairly well understood.¹⁶ The Carboniferous oil shale occurs at the surface around Hillsborough, Albert Mines, and Rosevale in Albert County; around Sussex and Norton in Kings County; and around Dover and Saint-Joseph in Westmorland County. Elsewhere in SE New Brunswick it lies in the subsurface at depths as great as 3–4 kilometres, from Sackville to Moncton, then Sussex and Norton. North of this, under a triangular swathe of the province with Fredericton at the apex and Bathurst and Shediac at the ends of two sides, Carboniferous rocks younger than the oil shale lie at the surface, and whether the oil shale lies beneath is not known. Outside of these zones only a small area around Campbelltown and Dalhousie shows any promise. Elsewhere the geology suggests no realistic probability of useful discoveries. Consequently, current production licences are issued around Sussex and Stoney Creek, and exploration licenses have been issued over a wider area.

5. Can exploration itself, especially *seismic* exploration, cause groundwater problems?

Seismic techniques are used to image the structure of rock layers below the surface. This is done using a principle similar to that of sonar imaging of the sea floor from boats. Seismic waves are generated either by small explosive charges or by using “thumper” trucks (heavy vehicles that pound the ground with a hydraulic ram).

Use of explosives raises safety concerns (but it should be borne in mind that construction of a 1 kilometre road cut through rock uses more explosives than have ever been used in sixty years of seismic exploration in NB), and there are already regulations regarding how close to dwellings and wells explosives can be used (New Brunswick Oil and Gas Act). Thumpers do not use explosives at all and there is no reliable evidence of these trucks causing well problems or damage to buildings.

6. What would be the impact of shale production sites on New Brunswick?

The impact would depend on how many producing wells were established. The use of directional drilling means that up to thirty wells can radiate from one well site. In BC the spacing of production wells is around 2 kilometres where a shale layer 1–2 kilometres below ground is being exploited. The well sites themselves cover 2–5 hectares depending on whether fluids are stored in ponds or tanks. Once production begins, the drilling equipment and fluid storage facilities can be removed, leaving a valve station and possibly a compressor, which reduces the impact considerably. The figure of “as many as 60,000 wells in New Brunswick” quoted by the anti-shale gas lobby is an example of a number plucked out of the air with the intent of fear mongering.⁴ Even if every area in NB that is underlain by the oil shale proves to be productive it would be difficult to fit 10,000 wells on it, let alone with 2-kilometre spacing.

7. What is New Brunswick's shale gas potential?

Again, this is a difficult question to answer. The oil shale exists and the layer in places is over 1 kilometre thick carrying between 4 and 20 percent by weight kerogen. Shales currently being exploited in the U.S. are generally less than 200 metres thick and have a kerogen content less than 4 percent. On the face of it, this suggests a large resource, but the test well at Elgin, hydrofractured in 2011, yielded nothing significant. It is not simply a matter of drilling the oil shale, hydrofracturing it, and waiting for the gas to flow. Many technical issues will have to be resolved before anyone can calculate the reserve—a reserve being the amount of gas in the ground that can be extracted at a profit. Figures circulating at the present range from educated guesswork to pure hype. Setting regulations on a minimum depth at which hydrofracturing can be carried out, and safety setbacks from faults, would further reduce any reserve figures.

8. What about regulation?

As the province is no stranger to oil and gas exploration and production, there are already regulations in place contained in the provincial Oil and Gas Act, the Clean Air Act, and the Clean Water Act. These regulations are subject to continual technical review and can be upgraded whenever necessary. The regulations are enforced by an inspectorate and are part of the environmental review process that all exploration and production licences are subjected to prior to approval. Horror stories coming from the U.S. (when they have substance) are telling us what happens when an industry is deregulated and indulges in a free-for-all. The 2005 law left state regulators to pick up the slack, and thirty years of “small government” has ensured that these regulatory agencies are underfunded and understaffed to the point where they cannot function effectively. As recent advisory reports in the UK and from Duke University have pointed out,¹⁵ strong regulation is essential if one natural resource industry is not to compromise other natural resources, especially groundwater. Hardly any publicity centred on North Dakota and British Columbia, where shale gas development has gone on alongside strong regulation.

Conclusions

Aside from the issues of greenhouse gas emissions, hydrocarbons are a finite resource: at some point they are going to become too expensive to use in the profligate way they have been used for the last two centuries. The transition to renewables can be a process managed with foresight or a chaotic transition driven by a panicking financial sector (with all the social problems that entails).¹⁷ Of the three hydrocarbon fuels—coal, oil, and gas—the last emits the lowest amount of CO₂ for units of energy released. If natural gas is used to generate electricity and replaces coal and oil, CO₂ emissions could be reduced by 25 percent across North America. (If it was used in combined heat and power plants also capable of using biofuels, agricultural, forestry, and timber-processing waste, plus combustible garbage, the reduction could be as high as 30 or 35 percent.) Countries such as Sweden, Denmark, and Germany, already much further down this road than Canada, still envisage natural gas as part of the energy mix for decades to come. France, which has reduced its CO₂ emissions even more, relies on nuclear power for 70 percent of its electricity generation.

Renewables on their own do not obviate the need for natural resources. Consider just solar power, wind turbines, and tidal generators. Any metal parts at some point were mined and their processing required energy (in the case of aluminium, huge amounts of energy generally from hydropower), and plastics ultimately came out of an oil well. The rare earth metals, as well as cobalt, indium, gallium, yttrium, etc., essential for the new technology in modern generators and solar panels, also came out of a mine somewhere, and fabrication employs toxic compounds and solvents (the groundwater problems associated with California's Silicon Valley over the last thirty years are extensively documented). Green energy projects also have a major impact on land use.

Whether energy projects involve hydrocarbon exploitation or green renewables, issues of public concern are involved, and informed public debate must be part of the decision-making process. The issues are too important for the debate to be hijacked by those who see fear mongering as furthering whatever agenda they may have, or who want to surrender all responsibility to “market forces.” Informed debate based on some rational assessment of facts and risks is essential. The role of government here is paramount: only government can represent the public interest (companies, by law, cannot represent anything other than the financial interests of their shareholders, and the public not only elect government, their taxes pay for salaries and pensions). Strong and robust regulation is the only way to avoid the problems experienced south of the border, and as New Brunswick comes to this development at a relatively late stage (and production lies several years away), it has the opportunity to learn from mistakes made elsewhere and from regulations

that have proven effective. Regulations need to be strong—that is, comprehensive enough to minimize risks—and robust, meaning properly enforced. Government needs to move away from a “bargain basement” approach (“we’re open for business” with low royalties and minimal regulation) to the sound development of provincial resources, and ideally resource development should involve direct benefit to the province rather than just collecting royalties.

Industry must also realize that a “trust us” approach cloaked in secrecy no longer works. Public trust of industry and government is at a premium just now, and industry must realize that it must work to regain that trust. Seismic activity associated with oil and gas extraction has been known and documented for nearly a century. It serves no one’s interest to deny it or dismiss it—an honest discussion of scale and risk would be more productive in the long run. Likewise, full disclosure of the amounts of water used in hydrofracturing, and the chemical additives used, would be a step in the right direction (and no more hiding behind “proprietary licences”).

The most positive move would be to formulate an energy policy for the province that specified how and where natural gas (including shale gas) would figure in. Simply permitting exploitation of shale gas and using royalties to pay down the debt is akin to selling off the family silver to pay the rent (even worse if the family silver goes for a major discount). Why not use a shale gas resource to manage the transition to renewables? (we’ll have to go there eventually). Replacing oil-burning power plants with combined heat and power facilities capable of using combustible garbage, forestry, agricultural, and timber processing waste alongside gas makes a value-added contribution and reduces the province’s carbon footprint (and eliminates an expensive imported fuel). In the final analysis, if shale gas proves to be a real resource, properly regulated and part of a development with vision for the future of the province, it offers more promise than threat.

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Endnotes

¹ An excellent summary of the history of mining and the petroleum industry is to be found in Martin, G. L. 2003. *Gesner's Dream: The Trials and Triumphs of Early Mining in New Brunswick*. Geological Society of Canada Publication.

² *The Last Billion Years: A Geological History of the Maritime Provinces of Canada*, published by the Atlantic Geoscience Society (2001), provides an excellent layperson's introduction not only to local geology, but also to many key concepts, such as the formation of oil and gas. Also informative is the New Brunswick Department of Natural Resources webpage at www2.gnb.ca/content/gnb/en/departments/natural_resources/Promo?Natural_Gas/CarboniferousGeology.html.

³ Energy Information Administration, U.S. Department of Energy, at www.eia.doe.gov.

⁴ I took part in a radio discussion with a prominent representative of the local anti-shale gas campaign in fall 2011. The exaggerated figures I subsequently quote come from this radio broadcast or related websites. This is also an example of uncritical alternative media journalism, though by no means the only one. The podcast is available at <http://chsrfm.ca/blog/2011/11/08/can-episode-2-what-the-frack-hydraulic-fracturing-in-new-brunswick/>.

⁵ *Gasland* is a 2010 film directed by Josh Fox that deals with methane leaks and other problems allegedly brought on by shale-gas hydrofracturing in west Pennsylvania, Texas, and Colorado. *Be...without Water* is a 2012 film directed by Ron Turgeon, narrating the issues some fifty families near Penobscis, NB, have had with water wells failing over the last decade.

⁶ See Mooney, C. "The Truth About Fracking." *Scientific American* (November 2011): 80–85. Also available at www.ScientificAmerican.com. Mooney's article addresses all the points usually raised by the anti-shale gas movement but the tone is refreshingly free of the apocalyptic imagery. For an interesting comparison between the methods of anti-shale gas and anti-GM crop activism, see Richard Black's article "Is shale gas the GM of energy?" at www.bbc.co.uk/news/science-environment-17741416.

⁷ The issues associated with groundwater are dealt with in more depth and greater expertise at www.unb.ca/initiatives/shalegas/. The authors of this article are a UNB hydrogeologist and geochemist, geophysicist, river scientist and drilling engineer, none of whom are associated with industry or government, or the anti-shale gas lobby.

⁸ See Osborn, S. G., Vengosh, A., Warner, N. R. and Jackson, R. B. 2011. "Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing." *Proceedings of the National Academy of Sciences of the United States of America*. Available at www.pnas.org/content/early/2011/05/02/1100682108.

⁹ The chemicals considered here are based on the additives list released publicly for the Elgin test well in 2011. Other chemical data regarding formaldehyde, glutaraldehyde, and polyacrylamide come from Google searches for these chemicals.

¹⁰ See for example Haszeldine, S. 2012. "Shale gas, NW England earthquakes, and UK regulation Briefing Note" for DECC SAG 21 November 2011, update February 2012 (Sect. 10), update April 2012 (Sect.12) available www.decc.gov.uk/assets/decc/11/about-us/science/5223-shale-gas-nw-england-earthquakes-briefing.pdf. This document also illustrates the mining-related earthquakes occurring in the same region. They are far more common and of the same

magnitude as the Blackpool earthquakes beneath the northern part of the Greater Manchester area, producing no damage or threat to life.

¹¹ See www.bgs.ac.uk/research/earthquakes/blackpoolApril2011.html; www.bgs.ac.uk/research/earthquakes/blackpoolMay2011.html; also <http://maps.bgs.ac.uk/GeoIndex/default.aspx>. The Richter magnitude scale for earthquakes is logarithmic, such that magnitude 2.0 is ten times magnitude 1.0, and 3.0 ten times 2.0. Unless the earthquake rupture is especially shallow (< 4 km depth), earthquakes of less than magnitude 3.0 are not felt at the surface. It is often difficult to detect earthquakes less than magnitude 2.0 in urban areas because they are masked by background noise, such as that produced by heavy traffic.

¹² Geological Survey of Canada earthquake archive at <http://www.earthquakescanada.nrcan.gc.ca/cite-eng.php>.

¹³ British Geological Survey 1:50,000 Solid Geology maps 1977 Blackpool sheet.

¹⁴ U.S. Geological Survey earthquake archives at <http://earthquake.usgs.gov/earthquakes/>.

¹⁵ The UK advisory report prepared by the Royal Society and Royal Academy of Engineers appeared in early July 2012. At the time of writing the complete document was not available online, but a summary can be seen at www.raeng.org.uk/news/releases/shownews.html?NewsID+711.

¹⁶ The geological maps of New Brunswick are all available through the NB Department of Natural Resources website, but a summary is available at the address cited in note 2. For the Duke University report see Jackson, R. B., Pearson, B. R., Osborn, S. G., Warner, N. R. and Vengosh, A. 2011. "Research and Policy Recommendations for Hydraulic Fracturing and Shale-gas Extraction." Nicholas School of the Environmental and Earth Sciences, Duke University, available at www.nicholas.duke.edu/cgc/HydraulicFracturingWhitePaper2011.pdf.

¹⁷ For a fairly readable and rational discussion of this see Leggett, J. 2005. *The Empty Tank: Oil, Gas, Hot Air and the Coming Global Financial Catastrophe*. New York: Random House. Written before the 2008 financial crisis, it has the benefit of being tested by subsequent events.