

Fracking Up Our Water, Hydro Power and Climate

BC'S RECKLESS PURSUIT OF SHALE GAS

by Ben Parfitt



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November 2011

Photographs © Garth Lenz

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1400—207 West Hastings Street
Vancouver BC V6B 1H7
604.801.5121 | ccpabc@policyalternatives.ca

www.policyalternatives.ca



PO Box 2205, Station Terminal
Vancouver, BC V6B 3W2
604.683.8220 | info@wildernesscommittee.org

www.wildernesscommittee.org



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ABOUT THE AUTHOR

Ben Parfitt is the resource policy analyst with the Canadian Centre for Policy Alternatives—BC Office. He is a long-time writer on natural resources, co-author with Michael M’Gonigle of *Forestopia: A Practical Guide to the New Forest Economy*, and author of *Forest Follies: Adventures and Misadventures in the Great Canadian Forest*. His most recent Climate Justice Project reports for the CCPA are *Making the Case for a Carbon Focus and Green Jobs in BC’s Forest Industry* (August 2011), and *Managing BC’s Forests for a Cooler Planet: Carbon Storage, Sustainable Jobs and Conservation* (January 2010).



ABOUT THE PHOTOGRAPHER

Garth Lenz is an internationally recognized conservation photographer based on Vancouver Island. His photography of environmental issues, threatened wilderness regions, devastation, and the impacts on indigenous peoples, has appeared in many of the world’s leading publications. He travelled with the author to northern BC to photograph fracking operations for this report.

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SUMMARY

Fracking Up Our Water, Hydro Power and Climate BC's Reckless Pursuit of Shale Gas

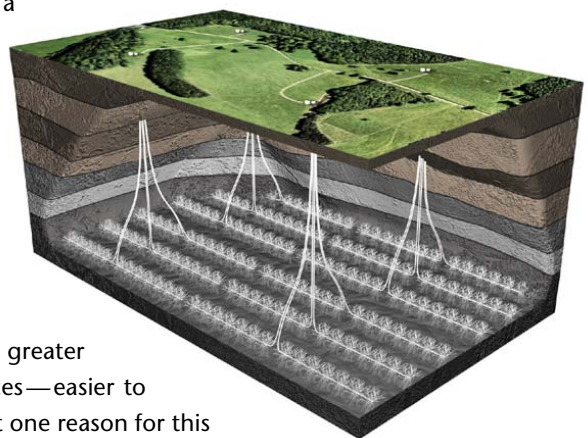
IN OCTOBER 2011, CANADA'S NATIONAL ENERGY BOARD GRANTED three companies permission to export liquefied natural gas from a terminal near Kitimat on British Columbia's north coast.

If these exports materialize, there will be a major spike in natural gas production in BC's north-east corner, with big consequences for the province's water and hydroelectricity resources and greenhouse gas emissions. That's because much of the gas will originate from deeply buried shale formations.

BC's shale gas production is the natural gas equivalent of Alberta's tar sands oil. Both require tremendous amounts of water and energy to produce, which is why they are sometimes called "unconventional" fossil fuels. But while the tar sands have been a flashpoint for heated public debate, BC's shale gas developments have flown largely under the radar screen, due to a persistent lack of information-sharing and public consultation by the provincial government. The government's reluctance to discuss the potential for massive increases in water and hydro power usage by the shale gas industry is troubling to say the least, as is the enormous potential for increases in greenhouse gas emissions as the shale gas industry expands its operations.

Getting shale gas out of the ground and into pipelines requires far greater effort than is the case with gas or oil from more conventional sources—easier to access reservoirs and more porous geologic formations—which is but one reason for this fossil fuel's heavy greenhouse gas footprint.

Shale gas is the natural gas equivalent of Alberta's tar sands oil. Both require tremendous amounts of water and energy to produce.



Industry and government promote natural gas as a “green” alternative to conventional fossil fuels that will bring much-needed jobs and revenue to BC. But this study reaches the opposite conclusion. Green resources in high volume—water and hydroelectricity—will be required to produce more and more dirty energy, in the form of a greenhouse gas emitting fuel.

Consider the following:

- Greenhouse gases associated with the production of BC shale gas are poised to double by 2020, meaning that every other sector in the provincial economy would have to cut their emissions by half for BC to meet its GHG emissions reduction targets.
- A recent BC Hydro assessment concluded that accommodating the projected power needs of BC’s shale gas sector would require two to three times the power produced at the proposed Site C dam on the Peace River.
- Shale gas industry records are being set for water usage and fracking at individual well pads in northeast BC, with up to 600 Olympic swimming pools worth of water used at some sites. Thousands of such sites could be developed in the decades ahead, in regions of the province where little meaningful data on water resources exists.
- Members of the general public and First Nations in whose territories shale gas projects occur are effectively out of the loop when it comes to being meaningfully consulted.
- BC is encouraging shale gas industry expansion through subsidies—which accelerate environmental degradation while simultaneously failing to capture maximum economic value from the resource—due to a glut of gas in North America and prevailing low prices.
- Regulation of industry activities, including controversial water withdrawals, is now largely in the hands of BC’s Oil and Gas Commission, whose primary mandate is to facilitate energy industry expansion, not to protect the environment.

Industry and government promote natural gas as a “green” alternative to conventional fossil fuels that will bring much-needed jobs and revenue to BC. But this study reaches the opposite conclusion.

FRACKING AND GREENHOUSE GASES

Currently, much of the gas produced in BC moves by pipeline to Alberta, where the biggest industrial user of natural gas is the tar sands industry. We are literally exporting the world’s most energy-intensive natural gas to help produce some of our planet’s most energy-intensive oil.

If liquefied natural gas (LNG) facilities materialize in BC, the scenario might change somewhat, in that a lot more gas would go by tanker to Asia. But it’s possible that BC ends up shipping more shale gas to both Asia and Alberta’s tar sands industry, and possibly more gas to Alberta for conversion to a range of liquid fuels, including diesel, naphtha and propane. Individually or collectively, these projects will dramatically increase GHGs in the jurisdictions that BC exports its gas to, while GHG emissions in BC will rise quickly as well.

Natural gas is often described as a greener alternative to coal and diesel, a “transitional” fossil fuel, because it creates fewer GHGs when burned. But gas production is another matter entirely. When all the emissions associated with fracking and its aftermath are factored in—including methane and CO₂ releases—shale gas may well be as dirty as coal. The BC government has scrupulously avoided discussing this, as well as avoiding regulations that would dramatically curb industry emissions.



MORE SHALE GAS: MORE HYDRO POWER DEMANDS OR MORE GAS BURNED

With power demands in the shale gas industry steadily increasing, there is considerable pressure to dramatically expand the province's hydroelectric transmission grid. If this happens, the potential ripple effect could be enormous, ultimately influencing a decision on whether to proceed with a controversial proposal to build a third dam—Site C—on the Peace River. In fact, if the shale gas industry expands as it is projected to do, it will need the equivalent of more than two Site C dams' worth of power. The drive to increase hydroelectricity production is coming from industry, and yet has been used by BC Hydro as a justification for increasing residential rates, which are already much higher than industrial rates. As a result, British Columbians subsidize the oil and gas industry's hydro consumption.

In the absence of increased hydro power transmission and/or increased hydro production, the default position will be to burn more shale gas to generate power, with that power then being used to drive the production of more shale gas—a double climatic whammy.

LITTLE RETURN ON PUBLIC INVESTMENT

The BC government has focused on the oil and gas industry as a key source of employment and prosperity, which may leave the impression that significant economic benefits outweigh environmental concerns. However, in 2007, oil, gas and mining accounted for less than one per cent of provincial employment, but nearly one third of industrial GHG emissions.

As natural gas prices have dropped, so have public revenues from royalties. Yet in the face of persistently low gas prices (due in part to a glut of available gas in North America due to upward revisions in estimates of available shale gas) the government continues to offer royalty breaks and infrastructure credits to the industry, which actually serve to lower public returns. The province and industry are both banking on that changing, should gas exports proceed, because the prices paid for gas in Asian markets are substantially higher than in North America.

The short-term gains in future revenues and jobs, however, ought to be weighed against the considerable environmental costs, begging the question: Why is BC subsidizing a polluting industry instead of developing a true green jobs plan?

The drive to increase hydroelectricity production is coming from industry, and yet has been used by BC Hydro as a justification for increasing residential rates, which are already much higher than industrial rates. As a result, British Columbians subsidize the oil and gas industry's hydro consumption.



A shale gas well pad under development in the Farrell Creek area near Hudson's Hope is indicative of the large scale of fracking operations in northeast BC, where a lack of water regulation is a worry to local residents.

FRACKING AND WATER REGULATION WOES

In the past 13 years, the BC government has reduced oversight of the oil and gas industry, thus enabling its rapid expansion. The fundamental change came in 1998, when BC established the Oil and Gas Commission (OGC) as a single regulatory body for the oil and gas industry.

Everything from logging and road-building approvals to the issuance of temporary water withdrawal authorizations is now handled by the OGC. This fundamental shift in industry oversight was followed in 2003 by the BC Oil and Gas Development Strategy, which included road infrastructure credits, royalty reductions, and regulatory “streamlining”—subsidies that saved the industry hundreds of millions of dollars.

Four years later, a short-lived provincial record for the sale of petroleum and natural gas rights (almost exclusively natural gas from shale deposits) was set.

When the OGC was created, it was also granted powers under the *Water Act* to assign to natural gas companies temporary rights of access to public waters, known as Section 8 permits. With this amendment, oil and gas companies became the only companies in BC to gain rights of access to water from an entity other than the provincial Water Stewardship Branch. Meanwhile, all other water users, from pulp and paper mills, to irrigation districts, to public utilities and municipalities, had to—and still must—receive approval from provincial water stewardship officials.

The regulations governing water use in BC remain hopelessly outdated, a fact highlighted by the current government's commitment to modernizing the *Water Act*. With growing questions being raised about water usage by the industry, the OGC decided in March 2011 to require natural gas companies to report their water usage under Section 8 permits. Welcome as the initiative was, the resulting reports failed to capture substantial volumes of water accessed by natural gas companies and obtained from sources not requiring OGC approvals.

The need for tighter regulations governing how the shale gas industry and other industries use water is obvious, as is the need to better monitor industry water uses. No more so than now, when climate change is having such a demonstrable impact on water resources. Now more than ever we need comprehensive changes in how water is assigned to the industry, how cumulative impacts on water resources are assessed, and how water resources are protected. Finally, we need changes in how water resources are priced to encourage water conservation and industry innovations.

RECOMMENDATIONS FOR CHANGE

With clear signs that the shale gas industry could expand to become a major consumer of provincial water and hydro power resources as well as a formidable climatic liability, this report concludes with a number of key policy recommendations. To begin the necessary regulatory reforms, the provincial government should:

- Place caps on annual shale gas production.
- Declare no-go zones where shale gas industry activities are excluded, and a moratorium on shale gas developments in undeveloped watersheds pending an independent panel review.
- Launch an inquiry under the provincial *Health Act* to assess the public health and safety risks associated with fracking operations in sour gas zones.
- End government subsidies of the gas industry.
- Require that shale gas companies pay adequately for the public water and hydro power that they use.
- Require full, publicly-accessible reporting of all water use in the shale gas industry.
- Require that the province report on its progress in lowering greenhouse gas emissions and outline how it will meet its emissions reduction targets while promoting increased shale gas production.
- Require that shale gas companies submit five-year and possibly 10-year development plans. This will help to ensure that the industry does not unduly compromise water, land and air resources, and that members of the public and First Nations are fully consulted.

In all, the report makes 18 policy recommendations that would ensure greater protection of green resources in the face of an expanding brown industry.

However, a bigger task lies ahead. How will BC wean itself off of dependency on fossil fuels—a challenge the province shares with every other jurisdiction on earth?

Ultimately the province needs to enact policies that result in a steady ratcheting down in the use of non-renewable fossil fuels that are destabilizing the earth's climate, with a corresponding rise in the use of energy sources that do not pump ever more greenhouse gases into the atmosphere.

This is what ultimately makes environmental and economic sense. We cannot base our economy, or the funding of public programs like health care and education, on the steady depletion of non-renewable, polluting fuels.

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Introduction: BC's Emerging Shale Gas Industry

THE EMERGENCE OF BRITISH COLUMBIA'S SHALE GAS INDUSTRY is part of a continental and, increasingly, global phenomenon. Ten years ago, a growing number of energy industry analysts believed North America was on the cusp of major shortages in domestically produced natural gas. A common discussion topic then was whether liquefied natural gas (LNG) ports would have to be built on the coasts of the continent for delivery from overseas.

Now the opposite is the case. Several LNG export terminals are proposed for BC's northern coast, with one—a proposed facility at Kitimat involving a partnership between Encana, Apache Canada and EOG Resources—already approved by provincial and federal environmental assessment review panels. The feedstock for the facility would largely be shale gas from northeast BC.

Unconventional gas sources such as shale gas have been known to exist for a long time. In fact, the earliest produced commercial natural gas in North America came from a shale gas well. But the shale in question was near to the surface, as opposed to the very deep shale zones now targeted for gas extraction.

While growing scarcity of conventional gas supplies has spurred today's development of shale gas, three industry innovations proved instrumental to the economic development of this unconventional gas resource. Shale is typically very tightly bound and does not yield its trapped gas easily. To free the gas, the rock is "stimulated." The stimulation method now in widespread use is hydraulic fracturing or fracking—a process where very large amounts of water are pressure-pumped down the wellbore and out into the surrounding rock to fracture that rock or create cracks in it that allow the trapped gas to more easily flow. When this technological innovation—which came into widespread use a little over a decade ago in the vast Barnett Shale in Texas—was combined with horizontal drilling (the second innovation) at several wells all drilled on the same well pad (the third innovation), the major hurdles to economic recovery of gas from deep shale formations were overcome.

Opposite page: Gas is flared from a large flare stack at a shale gas site in BC's remote Horn River Basin, 80 kilometres outside of Fort Nelson.

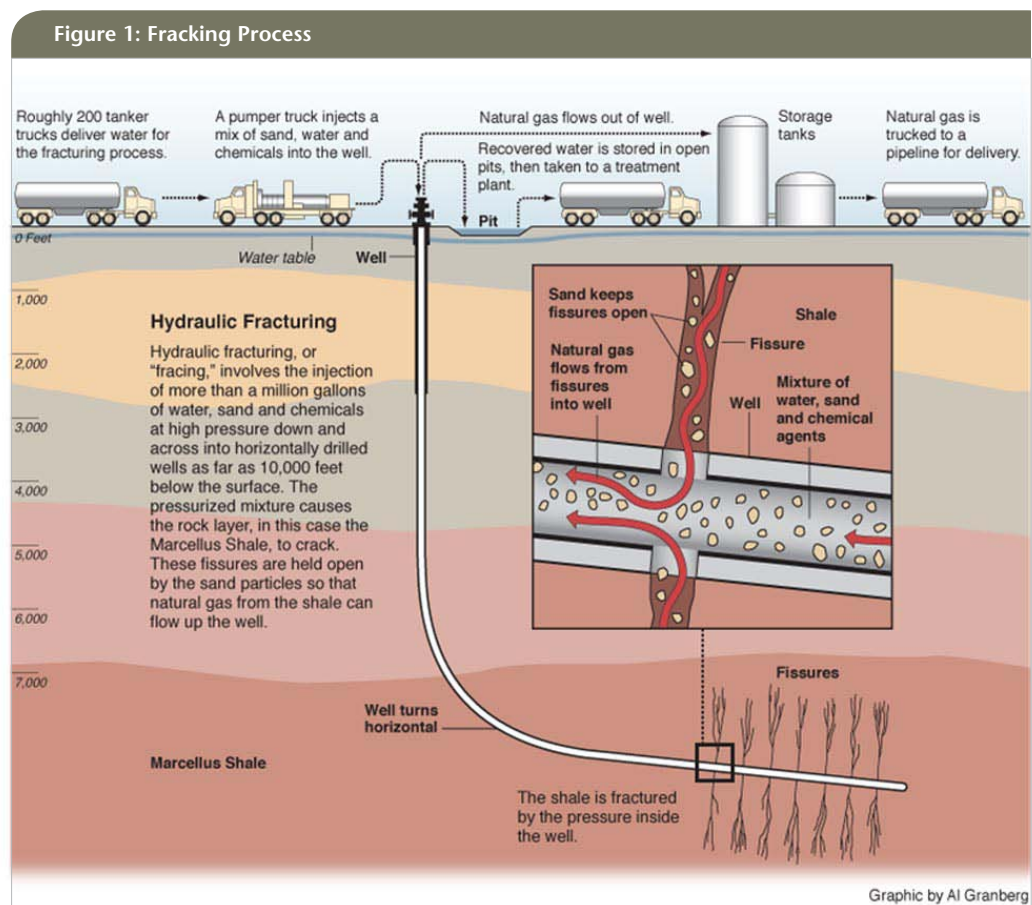
Ten years ago, a growing number of energy industry analysts believed North America was on the cusp of major shortages in domestically produced natural gas. Now the opposite is the case.

Horizontal drilling has been a boon to the unconventional gas industry. Drilling horizontally through long lengths of a targeted gas-bearing formation exposes much more of that formation to gas extraction than is the case if numerous vertical wells are drilled. When the ecological footprint of shale gas drilling is addressed by the energy industry, it is generally suggested that the industry treads lightly on the earth. The point is made—correctly—that fewer well pads and less pipeline infrastructure are required with horizontal drilling than with vertical drilling. One horizontal well may produce more gas than 10 conventional vertical wells. By locating numerous horizontal wells on a single well pad, moreover, the ecological footprint can be reduced further still. In northeast BC today, for example, 12 or more horizontal wells are typically drilled on a single large pad, reducing the need for a vast network of smaller well pads and their accompanying road and pipeline infrastructure.

Earthquake activity in fracking zones is becoming a matter of concern. As well, when fracking occurs in sour gas zones, there is a risk of gas leaks, which can be fatal due to the hydrogen sulphide in such gas.

However, this view of the environmental benefits of horizontal drilling ignores the still formidable fragmentation that occurs with such developments, the large amounts of water and energy required to do so, what such water usage means to surface and subsurface water resources, and the close proximity at which wells on multi-well pads are placed.¹ And the concerns do not stop there. Earthquake activity in fracking zones is becoming a matter of concern. As well, when fracking occurs in sour gas zones, there is a risk of gas leaks, which can be fatal due to the hydrogen sulphide in such gas.

According to projections from the Canadian Association of Petroleum Producers, shale gas from BC's two current major shale gas zones—the Horn River and Montney Basins—could account for fully 22 per cent of all of North American shale gas production by 2020. To provide further scale to this projection, the combined estimated annual production from the two basins that year



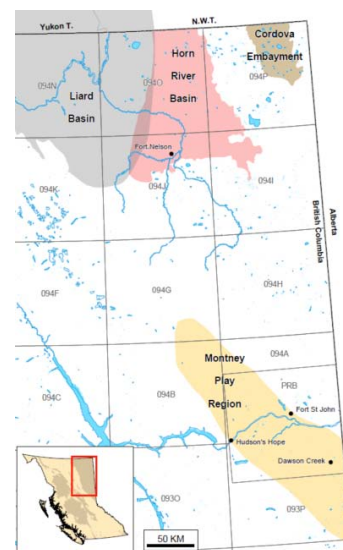
is 5 billion cubic feet of gas per day or, on an annualized basis, 70 per cent of all the gas used in Canada in 2009.²

Such production may provide the provincial government with sizeable revenues in the coming years. According to a recent provincial government budget document, the loss today of natural gas production in its entirety would mean that the province foregoes \$1.7 billion in gas royalties and leases, or fully 5 per cent of the province’s forecasted revenues for the fiscal year.³

People with working knowledge of what the industry requires to produce shale gas, however, note that there is a considerable environmental downside to a rapid escalation in production. In a recent energy industry publication, Grant Shomody, president of Grantech Engineering International, noted that developments in the Montney Basin alone presented formidable problems:

If this play develops as producers hope, the number of wells being drilled would severely tax local water resources. In that case, we can expect a lot of ecologically related criticism. There’s also the problem of disposing of the frac water or treating it for reuse. It’s expensive, and Montney producers have not installed water treatment capability at their plants.⁴

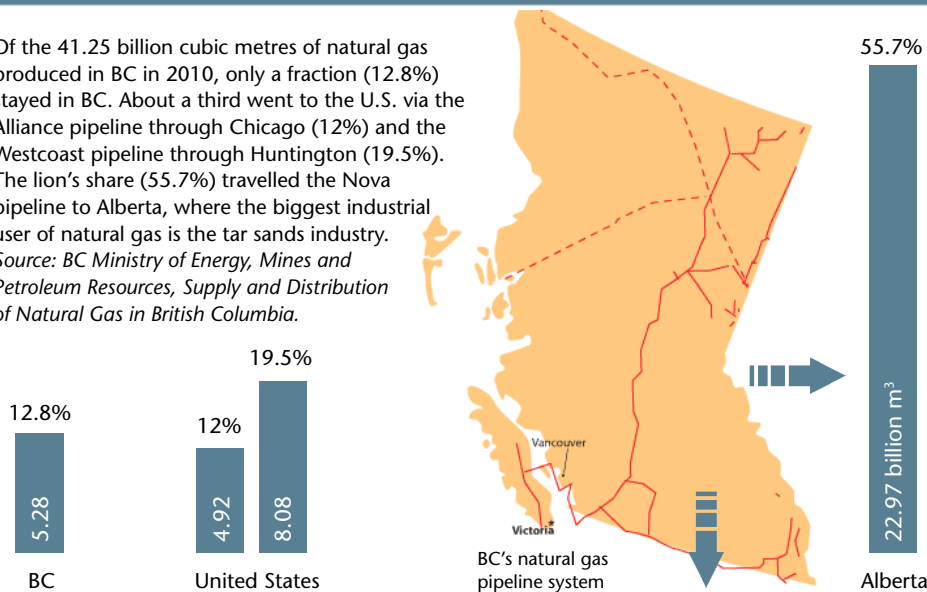
Already in BC, industry records have been set for water usage at individual multi-well shale gas pads. Early last year, 980,000 cubic metres of water was pumped underground at a single well pad operated by Apache Canada, an amount the company reported to its shareholders set a new benchmark for the industry. The water usage—equivalent to 392 Olympic swimming pools—was used in 274 successive hydraulic fracturing procedures performed at 16 wells at a remote site in the Horn River Basin named for one of the principle water supplies for the frack job—Two Island Lake. Each well was fracked sequentially an average of 17 times. In addition to the freshwater pumped belowground, 1.1 million pounds of fine-grained sand was also pumped. Such sand is required to keep the cracks in the fractured rock open, allowing the gas to flow out. As well, an undisclosed amount of chemicals were also pumped belowground. The volume of chemicals pumped at fracking operations has been estimated to range between 2 per cent and .5 per cent of the total liquid stream⁵—meaning that at Apache’s Two Island Lake multi-well site approximately 4,900 cubic metres of chemicals were injected.



Shale gas from BC’s two current major shale gas zones—the Horn River and Montney Basins—could account for fully 22 per cent of all of North American shale gas production by 2020.

Figure 2: Markets for BC Gas 2010, Gas Volume (billions of cubic metres) and Percentage

Of the 41.25 billion cubic metres of natural gas produced in BC in 2010, only a fraction (12.8%) stayed in BC. About a third went to the U.S. via the Alliance pipeline through Chicago (12%) and the Westcoast pipeline through Huntington (19.5%). The lion’s share (55.7%) travelled the Nova pipeline to Alberta, where the biggest industrial user of natural gas is the tar sands industry.
 Source: BC Ministry of Energy, Mines and Petroleum Resources, *Supply and Distribution of Natural Gas in British Columbia*.



This paper addresses some of the implications moving forward as the demand for and use of green resources such as water and hydro ramps up in BC's expanding shale gas industry, which in turn will likely translate into far higher greenhouse gas emissions.

The average horizontal wellbore length at Two Island Lake was 1,600 metres, a factor that helps to explain the huge volume of water required and why the water level at Two Island Lake declined by 15 centimetres due to continuous drawdown over a nearly four-month period—a rate of decline considered of such environmental significance that the company actually had to cease withdrawals. Meanwhile, later that same year Encana Corporation, Apache's industry partner in the Horn River Basin, easily bested Apache's record. At Encana's 63-K pad near Two Island Lake, the company drilled a total of 14 wells, with average horizontal reaches of 2,200 metres. A total of 316 stimulations or fracks were performed at the site, with a combined 1,488,560 cubic metres of water used. The total amount of freshwater used was 670,000 cubic metres. The rest of the water (818,560 cubic metres) came from a deep saline aquifer that Encana says will be the source of 90 per cent of its frack water in future years.⁶

A conservative projection of what the anticipated increase in shale gas production could mean for northern water resources is gleaned from Apache's projections for the Horn River Basin. The company states that it will drill 1,218 wells in the Horn River Basin by just 2034.⁷ If the company simply matches the standard set at Two Island Lake, the total water demand for this one company alone—and there are several large energy companies operating in the area including Encana, EOG Resources, Imperial Oil, TAQA North, SMR and others—will be in the neighbourhood of 130 million cubic metres.

How this will impact local water and land resources remains to be seen. But one thing is certain: by 2011, with industry records set for water usage in fracking operations in northeast BC, basic information on surface water supply was still unavailable and would not be available for some time to come.⁸

Worse still was the lack of solid information on subsurface or groundwater supplies, a fact explained by BC being alone among Canadian jurisdictions in not regulating groundwater usage.

Where all such water will come from, how the voluminous toxic wastewater that typically flows back up wellbores following fracking will be disposed of, and how regional water and land resources will be negatively affected by freshwater withdrawals and wastewater disposal, are all questions of central importance.

Complicating matters, BC's remote Horn River Basin and nearby Liard Basin, which is undergoing exploration, are not connected to the main provincial hydroelectric network. Currently, electricity in and around Fort Nelson, the largest community in the region, comes primarily from natural gas-fired turbines. But with power demands in the region's shale gas industry steadily increasing, there is considerable pressure to dramatically expand the province's hydroelectric transmission grid. If this happens, the potential ripple effect could be enormous, ultimately influencing a decision on whether to proceed with a controversial proposal to build a third dam—Site C—on the Peace River.⁹ Irrespective of a new dam being constructed, it is clear that an expanded shale gas industry in BC would need to harness more "green" hydroelectric power in order to produce more "brown" or greenhouse gas-intensive fossil fuel.

This paper addresses some of the implications moving forward as the demand for and use of green resources such as water and hydro ramps up in BC's expanding shale gas industry, which in turn will likely translate into far higher greenhouse gas emissions.

The paper concludes with a series of recommendations designed to ensure:

- Greater conservation of water and hence hydro resources;
- Lower greenhouse gas emissions by shale gas producers; and
- A proper financial return to the public in the event that the province's shale gas resources are more fully developed, such that we can plan for years when this industry is no more.



Revenues flowing in, but public subsidies flowing out

A key initial step was taken in 1998 when the province established the Oil and Gas Commission with the express purpose of creating a single regulatory and approval window for oil and gas activities.

THE NATURAL GAS SECTOR IN NORTHEAST BRITISH COLUMBIA has been firmly established for a number of decades, but only in the past 10 years or so have funds from the sector begun to assume the central importance that they do today for the provincial treasury.

Three significant developments propelled the revenue stream sharply upwards.

The first was a growing understanding that conventional sources of natural gas in the Western Sedimentary Basin, which underlies major portions of BC, Alberta and Saskatchewan, were on the wane. Tightening conventional gas supplies in the Basin as elsewhere in the world drove prices up, which spurred a concerted period of new exploration.

New exploration coincided with the emerging development of the Barnett Shale, a massive shale formation underlying portions of Texas. As natural gas companies perfected hydraulic fracturing techniques in the Lonestar State, forecasted availability of natural gas in North America and in northern BC soared.

The third factor was a provincial government anxious to grease the gas rush. In the early 1990s, there were about 200 wells drilled each year in the province. By 2007, that number had jumped more than sixfold to 1,300, a development that the Business Council of BC attributed to policy changes that began under a provincial New Democratic Party administration and continued under successive Liberal administrations.

“A key initial step was taken in 1998 when the province established the Oil and Gas Commission with the express purpose of creating a single regulatory and approval window for oil and gas activities,” the Business Council reported in October 2008.¹⁰

With the creation of the OGC, energy companies no longer applied to different agencies for regulatory approvals. Everything from logging and road-building approvals (previously requiring Ministry of Forests consent) to the issuance of temporary water withdrawal approvals (previously requiring Ministry of Environment consent) were now handled by the OGC. As a result, the new regulator soon became known as “the one-stop-shop” for the energy sector.



This fundamental shift in industry oversight was paired with equally important policies under the Liberals. “With a stated goal of making British Columbia the most competitive oil and gas jurisdiction in North America, in May 2003 the government unveiled four pillars of its Oil and Gas Development Strategy: (1) road infrastructure development; (2) targeted royalty reductions for marginal, deep wells and for summer drilling; (3) further regulatory streamlining; and, (4) an oil and gas service sector development initiative,” reported BC’s Business Council.¹¹

REVENUE RECORDS BEGIN TO BE SET

This suite of policy changes came at the opportune time—just as North American natural gas companies began to reap the dividends of the technological changes that made possible the economical extraction of larger volumes of shale gas.

Four years after the 2003 policy changes, a short-lived provincial record for the sale of petroleum and natural gas rights (almost exclusively natural gas) was set.

The bonus revenues collected by the province in 2007 totaled \$1.04 billion. A year later, the bonus bid record was shattered, reaching \$2.66 billion.¹² Upon setting the new and current record, then provincial energy minister Richard Neufeld said: “In these times of global economic uncertainty, it is comforting that B.C.’s oil and gas industry provides funding that ensures the stability of health care, education and many other programs that sustain the well-being of British Columbians.”¹³

A shale gas well pad is readied for fracking operations in BC’s remote Horn River Basin north of Fort Nelson, where provincial government subsidies have helped pave the way for an unprecedented fossil fuel rush.

The focus of much of the industry's bidding frenzy was deeply buried shale rock formations underlying the Horn River Basin and the Montney Basin, "both areas of significant shale gas potential."¹⁴

For their part, natural gas companies frequently tie their presence in BC to provincial policies that keep costs low. In a revealing article in the industry publication *Alberta Oil Magazine* in June 2011, the magazine singles out a favourable land tenure system, a "net profit royalty program," and hundreds of millions of dollars in "royalty infrastructure credits" (essentially provincial government-funded underwriting of infrastructure costs), as critical factors to attracting and keeping energy industry investments in the province.¹⁵

More recently, some in the business press have questioned whether the industry shine for BC's sympathetic pricing policies and favourable business environment is waning. In April 2011, the *Globe and Mail* intoned that there had been a dramatic drop-off in what it called the "multibillion-dollar rush" to snap up rights of access to the province's shale gas resources.

"This year, B.C. has collected just \$17-million in three auctions, putting it on pace for its worst year of exploration land sales in nearly two decades," the newspaper reported, adding that "if the trend continues, the final tally would be down about 90 per cent from the \$844-million invested in 2010."¹⁶

The article's inference that natural gas companies are souring on BC is probably overstated. A more likely explanation for the precipitous decline in bonus bids is simply that the industry has amassed the rights to everything worth developing in BC's two biggest shale gas zones—the Horn and Montney Basins—as well as much of the subsurface rights to the Liard Basin and Cordova Embayment. Now, the actual work of developing the gas resources begins.

As *Alberta Oil Magazine* observed in response to the *Globe's* prognostications: "...if there's any handwringing that B.C.'s shale gas boom is about to go belly-up, it's hard to notice in communities like Fort St. John, Dawson Creek and Fort Nelson that lie in the heart of the plays that brought the industry here in the first place—the Horn River and Montney basins."

The magazine went on to note that demand for the "cleanest-burning" of all fossil fuels "continues to increase, and with conventional supplies declining in North America, there's a need for natural gas even if the pricing environment doesn't look very promising right now."¹⁷

GLUT OF AVAILABLE GAS LEADS TO DEPRESSED PRICES

Indeed, prices for natural gas are low and have been for some time. From an historical high base price of US\$15.38 in December 2005, prices were hovering right around the US\$4 range in August 2011 and had rarely reached the \$5 level throughout much of 2010 and the first half of 2011.¹⁸ Between January 2006 and January 2008, by comparison, gas prices hovered between US\$6 and US\$8.

Ironically, much of the drop in gas prices is attributable not just to a stagnating economy, but to a glut of available gas in North America, a glut that some energy industry analysts believe will continue due to increased forecasts of just how much gas may now be commercially extractable from major shale zones in Canada and the U.S. This reality should give us pause to ask: What's the rush? Why not leave the resource alone for now instead of subsidizing its extraction?

This reality should give us pause to ask: What's the rush? Why not leave the resource alone for now instead of subsidizing its extraction?

But instead, with natural gas companies and governments alike touting the benefits of escalated shale gas extraction—indeed its inevitability—the push is on to find new “higher value” uses for shale gas. It is here that the true greenhouse gas footprint of shale gas extraction comes into focus.

In August 2011, prices paid for liquefied natural gas (or LNG) rose to US\$15 per MMBtu¹⁹ in Asian markets including Japan and South Korea. Demand was also moving upwards elsewhere in Asian Pacific markets including China and India.²⁰

Such prices, combined with the “unforeseen surfeit” of natural gas in northeast BC, lies at the heart of a plan by three of the larger natural gas companies now operating in the remote northeast of the province to ship gas south toward Prince George in central BC and from there via a new pipeline to the port of Kitimat where a proposed new LNG export facility would super-cool the gas, turning it into a liquid that could then be piped into the holds of tanker ships bound for import terminals on the other side of the Pacific Ocean. The price prize now is Asia.

If the export plan becomes reality (it has passed provincial and federal environmental assessment processes and the companies have received permission to export the gas from the National Energy Board), it will, according to The Economist magazine, “be one of the continent’s most significant energy developments in decades.”

“Those in the vanguard of this global gas revolution say it will [also] transform the battle against carbon, threaten coal’s domination of electricity generation and, by dramatically reducing the power of exporters of oil and conventional gas, turn the geopolitics of energy on its head,” The Economist enthused.²¹

For now, however, North American gas prices remain low and will likely continue so until new markets open up for BC natural gas or new uses are found for it than the conventional applications of today. In light of such low prices, some people question government’s financial inducements. Why, BC’s two independent MLAs asked in the spring of 2011, does the province subsidize gas production at a time when markets are oversupplied and gas is being produced at or close to a loss?

“The rapid expansion of this industry, and the potential for it to continue to expand with the aid of incremental government assistance, has led to serious public policy questions being raised by more and more individuals and organizations,” said Bob Simpson, Independent MLA for Cariboo North, who along with Vicki Huntington, Independent MLA for Delta South, called on the provincial government to conduct a wide-ranging investigation into all aspects of unconventional gas developments in BC—a call supported by numerous organizations.²²

Tankers like the one below could soon ply the waters of coastal BC carrying liquefied natural gas (LNG) produced from shale gas wells fracked in northeast BC. One export terminal near Kitimat BC has already been approved (artist rendering below) and another two are being considered.



Shale Gas: Green, Transitional Fossil Fuel or Worse Than Coal?

Assessing the climatic merits of various fossil fuels based on just the emissions associated with their combustion ignores the emissions associated with the production of shale gas.

ITS PROPONENTS FREQUENTLY PORTRAY NATURAL GAS as the most climate friendly of all fossil fuels. That is because when natural gas is combusted, the resulting greenhouse gas emissions are low compared to other fossil fuels—half that of coal, for example.²³

The lower greenhouse gas emissions associated with combusted natural gas is one reason why natural gas companies and government regulators alike promote the conversion or retirement of coal-fired power plants and their replacement with “clean-burning” natural gas-fired electrical turbines.²⁴

But assessing the climatic merits of various fossil fuels based on just the emissions associated with their combustion ignores the emissions associated with the production of shale gas—emissions that may do much to counter industry assertions that this is the cleanest of fossil fuels.

It also ignores issues of how shale gas produced in BC is ultimately used. As we will see, BC’s shale gas has its own significant greenhouse gas footprint. And soon that footprint could be magnified many times over. That’s because a major destination point for the province’s natural gas is Alberta, where the tar sands industry is a major consumer of gas. What this means is that a natural gas with a heavy greenhouse gas footprint could increasingly be used to help produce one of the dirtiest forms of oil on earth.

Recently a team of scientists from Cornell University focused on the release of methane, a highly potent greenhouse gas, from shale gas wells and concluded that in the short-term (the next 20 years, during which many climate scientists say substantial reductions in greenhouse gas emissions must be made) shale gas production poses significant climatic risks.

The study, led by Robert Howarth at Cornell, concluded that there were significant greenhouse gas emissions—notably methane—at gas wells as they were fracked and subsequently as they went into production.²⁵



As noted earlier, in today's typical hydraulic fracturing operations, very large volumes of water are forced under extreme pressure down wellbores and out into the shale to fracture the rock, which stimulates the desired gas flow. Commonly, over the ensuing first few days and weeks after water injection, significant quantities of water flow back to the surface accompanied by large quantities of methane, so large in fact that the potent greenhouse gas has not been dissolved in the flow-back fluid stream.

The Cornell study also estimated the impact of the routine methane emissions after well development and concluded that there were numerous instances where the venting or leaking of methane at various points in the gas gathering and distribution system would add significantly to the industry's GHG emissions.

It also considered methane leaks from shale gas subsequently processed at gas plants and further methane releases from the transportation, storage and distribution of shale gas.

When all such emissions sources were considered, the team estimated that during the life cycle of the average shale gas well, somewhere between 3.6 and 7.9 per cent of the well's total production would be emitted to the atmosphere as methane, one of the most potent of all greenhouse gases. "Considering the 20-year horizon," the team reported, "the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal when expressed per quantity of energy available during combustion."²⁶

A twin-tanker water truck climbs out of the Peace River valley bound for shale gas racking operations in the nearby Farrell Creek area. Far from environmentally benign, shale gas may have a greenhouse gas footprint on par with coal.

The Cornell team's findings build on earlier work focused on shale gas production in Texas. A 2009 study by Al Armendariz, then with the Department of Environmental and Civil Engineering at Southern Methodist University in Dallas and now with the U.S. Environmental Protection Agency, concluded that the production of shale gas in Texas resulted in about 33,000 tons per day of additional greenhouse gas emissions (CO₂ equivalent). This meant that the industry's production-related emissions were equivalent to all the greenhouse gas emissions associated with two 750 megawatt coal-fired electrical generating plants.²⁷

The Cornell study has its critics, though, among them Michael Levi, director of the Program on Energy Security and Climate Change at the U.S.-based Council on Foreign Relations. Levi charges that the Cornell study:

- Uses weak data on methane leaks from well and pipeline infrastructure;
- Compares the emissions required to produce a gigajoule of coal versus a gigajoule of gas, but does not consider the more efficient gas powered generation technologies versus coal generation technologies;
- Fails to consider the relatively "cheap" technological fixes that could reduce associated methane leaks; and
- Looks at 20-year global warming potentials, versus longer time frames that would make gas look more favourable.²⁸

But Levi does have one significant caveat to his critique, which relates to the Cornell study's choice of a 20-year timeframe to draw conclusions about the climatic impacts of moving forward of shale gas developments. A shorter timeframe makes shale gas look worse than coal, a longer time frame tilts things in favour of gas versus coal (relatively speaking, that is, since the combustion of both results in greenhouse gas emissions).

"...given a lot of rhetoric out there about nearish-term tipping points," Levi says, "it isn't entirely clear to me that it's consistent to turn around and say that we should only look at impacts averaged over a hundred years." In other words, what happens in the near term may be very important if a feared climate change tipping point is to be avoided.

BC'S SHALE GAS — MUCH OF IT HIGH IN CO₂

Another important greenhouse gas consideration in BC is that one of the province's major shale formations has exceptionally high concentrations of CO₂ that will, based on current industry practices, be vented to the atmosphere and significantly increase BC's greenhouse gas emissions.

In November 2009, a document released by Canada's National Energy Board noted that the shale gas from BC's Horn River Basin contained approximately 12 per cent CO₂. "This is a significant increase over the average two per cent CO₂ content for all gas pools in British Columbia and could represent a significant addition to B.C.'s and Canada's carbon emissions if the CO₂ is vented to the atmosphere," the report concluded.²⁹



One of the province's major shale formations has exceptionally high concentrations of CO₂ that will, based on current industry practices, be vented to the atmosphere and significantly increase BC's greenhouse gas emissions.

Mark Jaccard, a professor of environmental economics at Simon Fraser University's School of Resource and Environmental Management, subsequently amplified the NEB's concerns, noting that there is an inherent contradiction between BC's stated objective to drastically reduce greenhouse gas emissions and the province's continued efforts to encourage gas industry expansion.³⁰

Jaccard, who serves on the Intergovernmental Panel on Climate Change, has analyzed extensively global fossil fuel availability. His conclusion is that since such fuels will likely be used for decades to come it makes it imperative that the CO₂ in Horn River Basin gas be captured and stored by pumping the greenhouse gas deep underground. Otherwise, there will be further dangerous build-ups of greenhouse gases in the earth's atmosphere.³¹

In the case of Horn River Basin shale gas, Jaccard notes that industry and government projections are that by 2020 natural gas companies could produce 2 billion cubic feet of gas per day. Currently, companies extracting such gas remove excess CO₂ to increase the heating efficiency of the gas and make it safe for pipeline transmission. Typically, once the excess CO₂ is stripped from the gas it is vented directly to the atmosphere.

The Jaccard study concluded that this source of CO₂ emissions alone would reach 4.3 million tonnes per year by 2020, "making it extremely difficult for B.C. to achieve its CO₂ reduction targets."³² More to the point, if the province hoped to reach its legislated reduction targets by 2020 while simultaneously pursuing increased shale gas developments, it would have to "reduce emissions throughout the economy by almost 50%" to hit the target and do so in just nine short years, Jaccard's report further warned.³³

Jaccard went on to note that because natural gas companies must strip excess CO₂ from the gas to make it suitable for pipeline transmission and end-use, the industry has already taken the first step toward what could be successful sequestration of the greenhouse gas. The needed second step would be to pump the gas deep below ground, thereby preventing it entering the atmosphere. Failure to do this and simply continue venting the gas as is current industry practice thus represents one of the most formidable challenges to BC coming even remotely close to hitting its GHG emissions reduction targets.

When combined, the research done at Simon Fraser, Cornell and Southern Methodist universities raises significant questions about the alleged climatic benefits of natural gas derived from unconventional sources such as shale and casts into doubt whether BC can make serious headway in curbing its GHG emissions.

To get an idea of just how significant the challenge ahead is, the Pembina Institute, which has closely analyzed both Jaccard's work and that of the Cornell University team, concludes that when all greenhouse gas emissions associated with the industry are considered, the possible outcome is a doubling of such emissions in the 10 years ending in 2020 from roughly 11.2 million tonnes in 2010 to 22.4 million tonnes in 2020, a conclusion that raises the bar considerably on the work ahead for the provincial government in meeting its legislatively mandated greenhouse gas emissions reductions.³⁴ In fact, the challenges in meeting the targets may be even steeper given that the Pembina estimate does not include all sources of GHGs associated with the natural gas sector. For example, the emissions associated with the transportation of goods and services to gas industry operations are not factored into Pembina's calculations, although this would be offset somewhat by BC's carbon tax and could be offset further still by climate policies yet to be enacted.³⁵



Continuing to vent the gas as is current industry practice represents one of the most formidable challenges to BC coming even remotely close to hitting its GHG emissions reduction targets.



More Brown Gas Means More Demands for Green Hydro Power

AS BC'S UNCONVENTIONAL GAS INDUSTRY EXPANDS, so too does the demand for electricity. More shale gas wells, more pipelines between wells, more gas processing facilities, and more "value-added" downstream facilities, such as proposed liquified natural gas terminals, all require lots of power to operate. This likely means that much more "green" hydro power will be needed to produce much more "brown," GHG-intensive gas. Either that, or as some in the natural gas industry advocate, the industry uses more gas to generate more electricity.

Residents in northeast British Columbia understand this better than most because they live in closest proximity to both some of the province's biggest hydroelectric projects and its biggest shale gas plays.

A case in point is in and around Hudson's Hope. The town is the closest settlement to the W.A.C Bennett and Peace Canyon dams. Built in 1967, the Bennett dam flooded the Finlay and Parsnip river valleys to create Williston Lake, one of the largest hydroelectric reservoirs in North America and the source of about one quarter of the province's electricity.

The area just to the west and north of town and not too far north of the Bennett Dam is also one of the most rapidly developing shale gas plays in the province, known as the Farrell Creek operating area. Talisman Energy, a Calgary-based company, is the main player there and was joined in 2010 as a partner by Sasol Ltd., a South African-based company and pioneer in the greenhouse gas-intensive gas-to-liquids industry (see *Turning Gas to Liquid Fuels* on page 26).

Talisman recently secured long-term rights to draw water from Williston reservoir, water that will be the major fluid source for its fracking operations now and in the foreseeable future.³⁷ Canbriam Energy, another Calgary-based natural gas company, subsequently was awarded similar rights of access. But it is much more than just the reservoir's water that Talisman, Canbriam and other shale gas producers want. Increasingly, it's power produced when the Williston's and Peace Canyon Dam's pent-up water is diverted into hydroelectric turbines.

More shale gas wells, more pipelines between wells, more gas processing facilities, and more "value-added" downstream facilities, such as proposed liquified natural gas terminals, all require power to operate. This likely means that much more "green" hydro power will be needed to produce much more "brown," GHG-intensive, gas.

Opposite page: Autumn light shines on the Peace Canyon dam and Peace River near the town of Hudson's Hope.

BC Hydro noted the prospect for more than an eight-fold increase in power demand by the province's oil and gas industry, which primarily in future years will be the shale gas industry.

Turning Gas to Liquid Fuels: Potentially Lucrative, But at Further Environmental Cost

Both coal and natural gas can, with the aid of chemistry and heat, be converted to liquid fuels. Because of depressed natural gas prices and generally much higher prices for gasoline, companies operating in northeast BC's shale gas industry are considering investments in facilities that would take gas and turn it into higher value liquid fuels.

"Since 6 thousand cubic feet of gas is worth about \$24 (U.S.), and one barrel of oil is worth about \$100, there is a tremendous profit margin if you can convert one to the other cost-effectively," the Globe and Mail's Nathan Vanderklippe noted in a recent article.³⁶

Talisman Energy and Sasol Ltd., two companies in partnership in developing shale gas resources in BC's Montney Basin, are considering piping gas to Alberta, where they might then invest up to \$5 billion in a new gas to liquids plant that would produce the equivalent of 40,000 barrels of oil a day.

Even with such a formidable financial outlay the returns would be far higher, the companies believe, than continuing to produce and market natural gas.

There is a major and paradoxical environmental downside to such a conversion. Forty per cent of the gas piped to Alberta could be used up powering the chemistry to turn the gas into the range of liquid fuels produced at the proposed facility.

Natural gas industry demand for more electricity was a fact of life in northeast BC well before the shale gas boom started. A case in point is the little known Fox Creek Substation completed at a cost of \$27.7 million in 2007.³⁸

The major components of the project were a new 138/25 kilovolt substation and associated 57-kilometre long overhead transmission line linking the new facility to the power line network originating at the Bennett Dam.

As the new facility, near the tiny community of Buick Creek north of Fort St. John, neared completion toward the end of 2006, then provincial Energy, Mines and Petroleum Resources Minister and local MLA Richard Neufeld cast the project as a boon to local residents who would soon "enjoy the same reliable supply of electricity as the rest of the province."³⁹

But a subsequent review of cost overruns associated with the project revealed that the "customers" who needed the power were not the small isolated communities and ranchers in the region (who were already serviced by power lines) but natural gas companies that needed not only more power, but more secure power to meet their needs as their network of gas wells expanded.⁴⁰

Approvals to build the Fox Creek Substation preceded the explosion in interest in northeast BC's shale gas resources, which has taken the issue of electricity demand in the natural gas sector to a whole other level that will further complicate the already extraordinary challenges (aging infrastructure, a growing population and growing power demand, and political pressure to cap power rate increases to name but three) facing the provincial power supplier.

In a 2010 analysis forecasting future energy needs, BC Hydro noted the prospect for more than an eight-fold increase in power demand by the province’s oil and gas industry, which primarily in future years will be the shale gas industry.

“Over the last five years the load has been relatively flat at approximately 500 GWh. Over the next 10 years, load is expected to dramatically grow to about 4,600 GWh. This is driven by anticipated gas development in North East BC and gas processing outside of the [region],” the BC Hydro analysis covering the 20 years ending in 2030/31 concluded.⁴¹ The same document went on to note that more than two thirds of that power demand (nearly 69%) was essentially attributable to projected shale gas developments in the Horn River and Montney basins.⁴²

By autumn 2011, however, BC Hydro had revised its estimates upwards. By then it forecast that meeting future power demands in the province would be challenged by “unprecedented load growth,” driven by rapidly increasing shale gas developments in northern BC, and, to a lesser extent, prospective mining operations. The electric utility and Crown corporation estimated that future power needs in the shale gas industry would range between 2,300 megawatts and 3,250 megawatts—a range that included gas developments in the Montney and Horn River basins and that assumed the construction of a number of northern LNG plants.⁴³

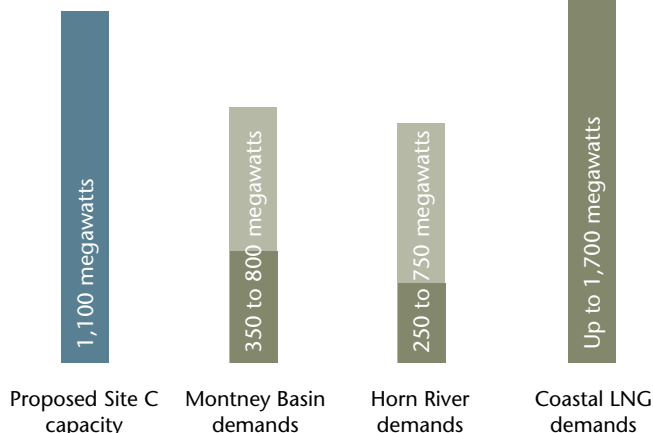
To provide some perspective on future power demand in the shale gas sector the proposed Site C dam, which would be the third dam on the Peace River below the existing Peace Canyon and W.A.C. Bennett dams, is worth considering. Site C would be a 1,100 megawatt facility. If BC Hydro’s low estimate of future power needs in the shale gas sector materializes, slightly more than twice the equivalent power at Site C must be found; and if its high-end estimate is realized, nearly three times as much. The fossil fuel industry’s accelerating power needs are something BC Hydro does not discuss in some of its more non-technical literature on new hydro infrastructure (see *Selling Site C* on page 28)

Largely absent from the discussion have been broader questions about just where the ultimately finite amount of hydroelectricity produced in BC ought best to go, and whether a significant portion of relatively clean, renewable hydro power ought to service an expanded natural gas sector, with all the additional greenhouse gas emissions that electrical usage would facilitate.

Figure 3: Shale Gas Industry Development Projected Hydro Demands

The proposed Site C dam would provide 1,100 megawatts of additional hydroelectric capacity, less than half the low-end estimate of the shale gas industry’s future power needs (2,300 to 3,250, assuming maximum LNG), and only about a third of the high-end projections.

Source: Bell 2011



This comes at a time when the province has been wracked by debate over proposed “run-of-river” hydro projects. Typically, the debates have centered on the environmental consequences of building such facilities. Hydroelectric power may well be “green” in that its greenhouse gas footprint is low. But it unquestionably has environmental impacts, most notably flooded lands, including farm land. Other equally divisive but important debates have revolved around issues having to do with public versus private power provision. Largely absent from the discussion have been broader questions about just where the ultimately finite amount of hydroelectricity produced in BC ought best to go, and whether a significant portion of relatively clean, renewable hydro power ought to service an expanded natural gas sector, with all the additional greenhouse gas emissions that electrical usage would facilitate.

This presents obvious challenges from an overall environmental perspective, as noted in a recent report by the Pembina Institute’s Matt Horne:

Although on-site, small-scale electrification is a relatively low-impact and non-controversial solution [to meeting some of the industry’s increased power demands], the same cannot be said for large-scale projects. Electrification of large-scale projects would likely result in controversy because of the necessitated increased generation and transmission infrastructure that would be required and that would likely result in significant land and water impacts.⁴⁵

In a spring 2011 publication, BC Hydro promotes the proposed Site C dam by saying that it is necessary to meet the needs of an expanding provincial population. There is no mention of industrial power use.

Indeed, Fort Nelson, northern BC’s largest human settlement, is far removed from the main provincial power grid and largely serviced by a natural gas-fired generating station that is currently being expanded. The provincial government plays this fact up in promoting a new transmission line that would link Fort Nelson to the main electrical grid via Fort St. John. In a recent estimate of the costs to build the 500-kilometre line that would link the two communities and tie into the

Selling Site C

In a spring 2011 publication, BC Hydro promotes the proposed Site C dam by saying that it is necessary to meet the needs of an expanding provincial population and that the power produced by running the dam’s impounded water through turbines would be sufficient to power 450,000 homes.⁴⁴

No mention is made in the publication about the impact that the proposed dam’s reservoir would have on flooding agricultural lands and First Nations territories.

“To meet B.C.’s future electricity needs, BC Hydro is encouraging conservation, upgrading its existing facilities, building new transmission and distribution infrastructure, and investing in new supplies of energy,” the publication reads.

“With Site C, BC Hydro is planning now so that British Columbians will continue to benefit from clean, reliable and cost-effective electricity in the future.”

Nor does the publication note to what end-uses its expanded transmission infrastructure would be put. There is also no mention of industrial power use, which would take the relatively clean power produced through hydroelectric projects and use that power to produce more non-renewable, greenhouse gas-intensive fossil fuels.



main provincial power grid, BC Hydro provides a range of between \$1.5 billion and \$2 billion. The estimated costs include new power stations in Fort Nelson and in the Horn River Basin shale gas zone. BC Hydro notes that prior to the infrastructure being built there would have to be a “commitment from [shale gas] producers to take service and contribute capital” to the project.⁴⁶ The capital cost contribution is not identified.

Such an expansion would be the biggest but by no means only transmission expansion of note in the broader northeast BC region to be fuelled by the shale gas industry’s growing demand for power. Another major transmission expansion may soon loop between the communities of Chetwynd, Dawson Creek, Taylor and Hudson’s Hope and cost upwards of another \$200 million.⁴⁷

Such proposed hydro infrastructure developments and their linkages to the province’s expanding shale gas industry have flown largely below the radar of the provincial media, while the proposed Site C dam has received comparatively lots of press.

Also flying largely below the radar screen is that even if all of this allegedly “clean” or “green” power hydro infrastructure is put into place, there will still be prospects for further use of gas-fired turbines to facilitate the expansion of the province’s northeast gas industry. That’s almost a given, due to the remoteness of the region, the rapidly expanding network of gas wells and the pipeline network needed to link them together.

As the Pembina Institute’s Matt Horne observed, “it is beyond the scope” of BC Hydro’s recent forecasting “to indicate how much [electrical or power] self-generation from natural gas and direct combustion of natural gas would still be occurring in the sector,” even as the province’s hydroelectric grid was expanded.⁴⁸

As the issues raised here suggest, the province likely faces a future in which more green (relatively speaking) hydro power is used in the non-renewable fossil fuel industry and more dirty shale gas derived power is used as well. All of which will place further strains on provincial water resources that face significant management challenges.

The Peace River could one day look very different should a third hydroelectric dam on the river—Site C—be constructed. A power-hungry shale gas industry could consume the equivalent of two to three times the power produced at Site C.

Costs to Our Water, Human Health and Safety



Oil and gas companies have become the only companies in the province to gain rights of access to water from an entity other than the provincial Water Stewardship Branch.

IN BRITISH COLUMBIA WATER RESOURCES are allocated under the provincial Water Act. Prior to a provincial government cabinet restructuring in October 2010, the lead agency responsible for administering the act and assigning water rights was the Ministry of Environment or MOE. Water stewardship officials in MOE had power to assign water rights in one of two ways: short-term (12 months or less) permits, also known as Section 8 permits, or for more long-term, secure tenures, water licences. In BC, the approach to assigning such rights—known as “first in time, first in right”—bestows priority rights to the first entities to be awarded water resources on a given water body. If water runs short, the first licensee has a priority right of access over later licensees. Most major water users in BC hold water licences, for the obvious reason that they provide greater security than short-term permits.

With the change in Cabinet, authority for granting water rights was transferred to the new Ministry of Natural Resource Operations, a very short-lived ministry that became the current Ministry of Forests, Lands and Natural Resource Operations (MFLNRO). This is where those people still left working in the Ministry of Environment’s old Water Stewardship Branch now work and are responsible for reviewing and approving water licence applications.

There is a significant exception to the water allocation framework outlined above. With the creation of the Oil and Gas Commission, the OGC was granted powers under the Water Act to assign Section 8 water permits. With this amendment, oil and gas companies became the only companies in the province to gain rights of access to water from an entity other than the provincial Water Stewardship Branch. The trend over the last few years, as fracking has expanded, has been for energy companies to receive access to water through Section 8 permits authorized by the OGC. It now looks like such approvals could take on added significance if the provincial government passes an amendment to existing statutes. Thanks to sleuthing by environmental lawyers with Ecojustice, it has come to light that the province is considering doubling the maximum length of the permits, meaning that energy companies could soon receive authorization from the OGC for rights of access to water resources for periods of up to two years.⁴⁹



Meanwhile, all other water users in the province, from pulp and paper mills, to irrigation districts, to public utilities and municipalities, must receive approval from provincial water stewardship officials in MFLNRO, with the bulk of such approvals usually being long-term water licences.

As of now, much of the water used by BC natural gas companies occurs under Section 8 permits granted by the OGC. A recent report by the Water Program at the Munk School of Global Affairs (by this author), noted that as of April 2010, the OGC had issued Section 8 approvals to energy companies allowing them access to surface waters at 540 different diversion points on rivers, lakes and streams in northeast BC. Had all the water under the permits been withdrawn to the maximum allowed on a daily basis, the companies could have diverted 274,956 cubic metres per day or more than 60.48 million imperial gallons. By comparison, the daily water use of all residences and businesses in the Greater Victoria area is less than half that volume or 134,282 cubic metres.⁵⁰ The actual water used by the industry under such permits is almost certainly far less. But in the absence of reporting, it is an open question as to how much water the industry uses and what the hydrological implications of such usage are.

With growing questions being raised about water usage by the industry, the OGC decided in March 2011 to require natural gas companies to begin reporting their water usage under Section 8 permits.⁵¹ Welcome as the initiative was, the inaugural industry water-use report left much to be desired (see *New Water Reporting Captures the Drops in the Bucket* on page 32).⁵²

A twin-tanker truck transports water to shale gas fracking operations near Hudson's Hope BC, shortly after a drought advisory was lifted in the fall of 2010. The industry's huge thirst for water has become a flashpoint for controversy wherever fracking has occurred.

With growing questions being raised, the OGC required natural gas companies to begin reporting their water usage under Section 8 permits. Welcome as the initiative was, the inaugural industry water-use report left much to be desired.



New Water Reporting Captures the Drops in the Bucket

Early in 2011, British Columbia's Oil and Gas Commission notified natural gas companies that they would have to begin filing reports on the total amount of water they used under water-use permits assigned to them by the commission.

The development heralded the beginning of what could be a more open era of information sharing on use of public water resources.

The first quarterly water-use report issued by the OGC raised a number of questions, however, some of which were addressed when the second such report was released three months later.⁵³ The biggest question was why the total amount of water reported as used was so low—just 89,000 cubic metres—when individual fracking operations in BC may consume 1 million cubic metres or more of water. The second related question was why fully one in four companies failed to report their water use information to the OGC.

With the issuance of the second report, there was a sizeable increase in the amount of water reported as used—more than 1.3 million cubic metres for the quarter. Companies failing to report their water fell considerably, a fact the OGC attributed to tickets and fines issued to offending companies the first time around.

But a bigger issue remains. The OGC's reports do not include huge volumes of unreported water—for example groundwater withdrawals—nor do they include the considerable volumes of water assigned to shale gas companies by the Ministry of Forests, Lands and Natural Resource Operations.

At present, the volume of water held by energy companies under water licences is considerably lower than the water held under short-term permits. A search of a provincial database shows that there are at least 19 licences currently in play,⁵⁴ with total assigned water volumes of 10.66 million cubic metres per year, or 29,217 cubic metres per day. The volumes of water assigned under the licences vary considerably from a high of 3.65 million cubic metres per year to a low of just 803 cubic metres.

Despite the low number of water licences at present, there are many applications for new licences currently before water stewardship officials with the new ministry of Forests, Lands and Natural Resource Operations. The Fort Nelson First Nation, for example, has more than a dozen such applications that have been referred to it for comment. In other cases, it appears that not all applications are being filed to First Nations for comment. For example, the West Moberly First Nations formally requested information on water licence applications within its territory in February 2011—requests that turned up an application by Talisman Energy to the provincial government seeking access to 3.65 million cubic metres of water per year from the Williston Reservoir. The company's application had been submitted to the provincial government five months earlier in October 2010, and the province had not at that time deemed it necessary to refer the matter to the First Nation for review and comment.

Overall, there is no formalized process for members of the public or First Nations to raise questions about Section 8 permit applications or water licence applications, and only narrow rights of appeal pertaining to water tenures, generally limited to impacts on riparian areas or the impacts that newly issued water tenures could have on existing licence holders. Nor is there opportunity to comment on the adequacy or lack thereof of the regulatory overview process. This is problematic because competition for finite water resources has broad implications for the general public. For example, the lack of public consultation around Talisman Energy's proposal to divert up to 3.65 million cubic metres of water annually from the Williston Reservoir was raised as a matter of concern in the provincial legislature on June 1, 2011. Talisman's application was subsequently granted, as was an application for long-term rights of access to a similar volume of water by Canbriam Energy. The W.A.C. Bennett Dam, which created the Williston Reservoir, is the single largest source of hydroelectricity in the province. BC Hydro, which maintains the dam, has major water licences on the reservoir, which could be affected by natural gas industry water withdrawals.⁵⁵ Due to a severe drought in the south Peace River region in 2010, water levels at Williston Reservoir fell, leading to questions about the sustainability of water use in the region more broadly, because many more water withdrawals by shale gas companies were occurring elsewhere in the region at numerous withdrawal points on local rivers, lakes and streams. Yet there was and remains no place for members of the public to review water licence applications before the Water Stewardship Branch and no similar opportunity to review and comment on Section 8 water use applications before the Oil and Gas Commission.⁵⁶

There is also no requirement that proposed takings from surface waters be subject to a provincial environmental review, unless such takings exceed 10 million cubic metres per year. Similarly, there is no scope for environmental reviews of proposed groundwater withdrawals unless they exceed a high threshold,⁵⁷ as is the case in a very limited way under federal regulations.⁵⁸

The result is that there is virtually no opportunity for public debate over the environmental impacts of specific proposed water withdrawals and almost no ability to engage regulators in any discussion on the *cumulative* impacts of multiple water withdrawals.

Five other points are noteworthy when considering water and the energy sector.

- First, BC lacks a comprehensive groundwater (or sub-surface) water licensing regime, making it difficult to determine what impact proposed groundwater withdrawals may have on both surface and groundwater supplies. The absence of a comprehensive regulation governing this important public resource has long been noted as a problem, and most recently was roundly criticized by provincial Auditor General John Doyle.⁵⁹ This is of concern because energy companies such as Encana Corporation have sunk wells into deep, saline aquifers in search of water supplies for their hydraulic fracturing operations, and others such as Talisman are known to be accessing groundwater from freshwater aquifers. All of this highlights why it is important for the provincial government to complete its promised Water Act Modernization process and introduce a comprehensive set of rules governing groundwater withdrawals and conservation.
- Second, there is clear evidence that energy companies are obtaining large volumes of water from sources that were, until only very recently, not subject to permitting requirements.⁶⁰ The most significant of such sources are the expanding number of borrow pits that are excavated to provide fill for roadbeds and well pads and that subsequently fill with water.⁶¹ In the northern Horn River Basin, the likelihood that such pits will fill with water is substantial given that the region is muskeg. The OGC now requires that all companies wishing to withdraw water from such pits first obtain a permit.⁶²

There is no formalized process for members of the public or First Nations to raise questions about Section 8 permit applications or water licence applications, and only narrow rights of appeal pertaining to water tenures, generally limited to impacts on riparian areas or the impacts that newly issued water tenures could have on existing licence holders.



There is virtually no opportunity for public debate over the environmental impacts of specific proposed water withdrawals and almost no ability to engage regulators in any discussion on the *cumulative* impacts of multiple water withdrawals.

- Third, there is no single source that members of the public can turn to in order to obtain regularly updated information on all water assignments and all water withdrawals. The OGC is in the early stages of partially rectifying this situation through issuing reports on water usage by natural gas companies holding temporary water-use permits. This captures some, but nowhere near all, of the water used by the industry; and came about largely as a result of the Commission appointing a full-time hydrologist to address water use, water assignment and water-tracking issues. Also, as a result of efforts to beef up its regulation of water usage, the OGC has begun to consult more with First Nations in an effort to arrive at a more fulsome process for consultations prior to water permits being issued.
- Fourth, there is no requirement at present that all water takings be reported to government regulators. A case in point: many approved water licences have zero reporting requirements, including a licence granting Imperial Oil access to nearly 2 million cubic metres (800 Olympic swimming pools) of water per year from the Peace River. In the absence of such requirements, it is virtually impossible to know whether companies are adhering to the rules. Even if reporting requirements became standardized, they would have little effect in the absence of stepped up monitoring and enforcement to ensure industry compliance.
- Fifth, as the energy industry expands it is clear that regulators and the industry alike have a poor understanding of surface water and groundwater resources. The lack of baseline data is further complicated by climate change and its predicted impacts on water supplies.

These substantive issues are also exacerbated by the fact that industrial water use carries little or no cost, which means there is no incentive to conserve.

WATER PRICING

Related to the above, but treated separately here, is the question of water pricing. When commonly used natural resources are underpriced or not priced at all, prospects increase that such resources will be squandered. Placing an appropriate price on a natural resource, one that reflects the marginal opportunity cost for its use, helps to ensure that such resources are used wisely and wherever possible conserved.

This is an important point when considering the escalating use of freshwater in the fracking process and in addressing the very large amounts of toxic wastewater produced by the industry. Most of the water pumped underground at fracking operations typically flows back up the well-bores after fracking ceases. This flow-back water is highly toxic and typically contaminated with the various minerals and other materials it has come into contact with belowground, along with traces of the chemicals used in the fracking process as well as some of the frack sand. This toxic waste must then be stored and re-used (most likely diluted with sources of new freshwater), or disposed of—either by injecting it deep underground at approved injection well sites or diverting it to approved treatment facilities, of which there are presently none in northeast BC.

At present, much of the water used by BC's fracking industry is obtained for free under Section 8 permits authorized by the Oil and Gas Commission.

A Partial Solution: Shale Gas Industry Water Innovations

Freshwater is not necessarily a prerequisite for shale gas fracking, although one would be excused for thinking so given the tremendous quantities being used in the industry today and being eyed for future use.

Some significant industry innovations with respect to water use include:

- Use of highly saline water from deeply buried aquifers. Encana and Apache are currently using large quantities of salty groundwater in their fracking operations in the Horn River Basin and have indicated that water from the Debolt aquifer will be their primary water source moving forward.
- Reuse of captured and contaminated flowback water in subsequent fracking operations, which Talisman Energy is doing at its Farrell Creek operations and which many other companies strive to do.
- Proposed use of treated municipal wastewater, underway in the Dawson Creek area as a result of investments by Shell.

These innovations and others are occurring. However, they are occurring at the same time that energy companies—including some of those just mentioned—are either ramping up their existing use of freshwater and/or applying for long-term rights of access to even more freshwater supplies.

The provincial Water Stewardship Branch, which allocates water licences, does, however, charge for water used by licence holders. The Branch publishes a schedule of annual water rental rates. It notes that as of 2009, for companies using water for purposes of “oil field injection”—a category that includes fracking—the rental charge is \$1.10 per thousand cubic metres. This means that for every Olympic swimming pool’s worth of water (or 62 truckloads) used in the industry, the payment to the Crown is a mere \$2.75.

Such a nominal charge appears unlikely to encourage conservation (see *A Partial Solution: Shale Gas Industry Water Innovations* above). To achieve the maximum recovery and re-use of wastewater—which would reduce the need to obtain ever-increasing amounts of freshwater under new Section 8 permits and water licences —the price shale gas companies pay for water must increase substantially. This includes both water obtained under short-term or Section 8 permits (which companies pay zero dollars for now) and water obtained under longer-term water licences (which companies pay only nominal fees for).

At present, much of the water used by BC’s fracking industry is free under Section 8 permits. Under Water Stewardship Branch licences, however, there is a fee: in 2009, \$1.10 per thousand cubic metres. This means that for every Olympic swimming pool’s worth of water (or 62 truckloads) used in the industry, the payment to the Crown is a mere \$2.75.

FIRST NATIONS: OUT OF THE LOOP

The Crown is under a constitutionally established duty to consult with First Nations, particularly with regard to decisions affecting lands and resources. In northeast BC this reality is reflected in various “Consultation Process Agreements” (or CPAs) reached between the former Ministry of Energy, Mines and Petroleum Resources and the Oil and Gas Commission on the one hand, and various First Nations on the other. (Such agreements expired in 2011 and are up for renewal.)

One such agreement signed with the Fort Nelson First Nation on December 1, 2006, specifies that consultations will take place with regards to “oil and gas activities,” especially those “that have the potential to adversely impact the exercise by the First Nation of rights recognized and affirmed by section 35(1) of the Constitution Act, 1982.”⁶³

The CPAs do not directly refer to water resources. However, it is clear that water usage by the oil and gas industry is subject to the terms of CPAs. The CPA with the Fort Nelson First Nation notes, for example, that an “oil and gas activity” “means those functions related to oil and gas exploration and development on Crown land within the Administrative Area for which the approval of the Oil and Gas Commission is required, and includes but is not limited to, seismic, well sites, access roads, pipelines and processing facilities.”⁶⁴

Since large amounts of surface and/or groundwater are required to produce gas from shale zones, water allocation and subsequent use is not only “related” to gas development but essential to its production, and therefore subject to the terms of the CPA.

As the OGC has ramped up its approval of Section 8 water permits, however, it is clear that not one single water use application by a natural gas company to the energy industry regulator was so much as referred to a First Nation prior to an approval being granted. A recent review of Section 8 authorizations by the Fort Nelson First Nation, moreover, shows that in some cases it took the OGC just one day to issue a water permit following submission of the company’s application. This included an instance in 2010 where the allocated water volume under a Section 8 approval to Apache Canada at its record-setting Two Island Lake fracking operation was increased by 100,000 cubic metres, allowing the company to boost its water takings at the lake from 200,000 cubic metres to 300,000 cubic metres. Neither the original permit obtained by Apache nor the amended permit was ever referred to the First Nation for comment prior to its being approved. The speedy issuance of the permits suggests the OGC’s allegiance is first and foremost to its energy company clients, not First Nations. (The impression that the OGC maintains overly close ties to the industry was lent further credence in 2011, when the head of the OGC, Alex Ferguson, left his job to take a position with Apache Canada.⁶⁵)

Recently, the OGC has taken steps to begin rectifying this situation by issuing a directive outlining how it intends to proceed with consultations with First Nations over natural gas industry water applications. The directive, however, would apply to only some industry water applications.⁶⁶

Prior to the directive’s issuance in September 2011, however, there was little to indicate that the OGC or provincial government was committed to a formalized consultation process with First Nations over water allocations and usage within their traditional territories. There has also been little attempt until only very recently to even consult with First Nations and the general public over what a proper notification and consultation protocol agreement might look like. The lack of effort to consult takes on added significance when the impact of actual energy industry water withdrawals is considered. Returning to the Apache Canada Two Island Lake example, the original permit deemed that it was acceptable to draw down the lake level by up to 10 centimetres and



Not one single water use application by a natural gas company was so much as referred to a First Nation prior to an approval being granted. In some cases it took the OGC just one day to issue a permit following submission of the company’s application.

no more. The amended permit, issued overnight, allowed the company to increase its drawdown a further 50 per cent. No ecological justification was provided for the sizeable increase in the approved drawdown. The company ultimately was forced to halt its water takings from the lake, after withdrawing some 270,000 cubic metres, because the lake level had fallen to just about the 15 centimetre threshold.

The situation with respect to consultation on proposed water licences is somewhat different. Notification of licence applications, along with some but by no means all related documents, are being forwarded to various First Nations—but not the general public. The referrals include a request by the province that the First Nation provide “comments and knowledge regarding the nature and scope of any aboriginal rights or interests claimed or practiced on, or adjacent to, the water under application.” Typical of such referrals is a May 27, 2010 letter from Front Counter BC to the Fort Nelson First Nation. The one-page letter and accompanying 33 pages of related documents, including photocopies of a completed two-page water licence application form, pertains to a request by Calgary-based TAQA North Ltd. to withdraw up to 2 million cubic metres of water annually for a period of five years out of the Fort Nelson River.⁶⁷

The letter goes on to say:

*We are not requesting a detailed submission regarding a claim in general but rather are seeking specific information readily available to you regarding activities carried out in the area under application, whether and how you consider that those activities may be affected by this application, and any proposals that you may have for avoiding, mitigating or otherwise accommodating your concerns.*⁶⁸

At least a dozen such letters have been received in recent months by the Fort Nelson First Nation, a strong indication that energy companies are intent on solidifying their water holdings through long-term licences. The letters are arriving, however, in the absence of any formalized consultation process with First Nations or the general public, and with no clear indication that First Nations will have any realistic prospect of influencing the regulatory review and approval process. Also, the letters provide no indication that the government is willing to engage with First Nations in any consultations around the cumulative impacts of multiple water withdrawals.

Complicating matters further, there is scant evidence that the OGC and Ministry of Forests, Lands and Natural Resource Operations have any process for working together to ensure that between the two agencies the public is presented with credible information to indicate that water resources are not over allocated or at risk of being overdrawn. Nor does there appear to be any evidence that the two agencies plan to coordinate efforts such that all water applications are subject to a consultation process that fully engages relevant First Nations and the general public on the broader issue of cumulative impacts on water resources as multiple water tenures are assigned and acted upon.

In the case of the Apache Canada Two Island Lake, the original permit deemed that it was acceptable to draw down the lake level by up to 10 centimetres and no more. The amended permit, issued overnight, allowed the company to increase its drawdown a further 50 per cent.

CHEMICAL USE

Chemicals introduced in the fracking fluid stream vary widely depending on the nature of the wellbore and targeted gas-bearing formation. As noted earlier, some state legislatures in the United States have made it a requirement that companies report the chemicals they pump underground at gas wells. Other states, notably New York where a moratorium is currently in place preventing shale gas developments in key watersheds supplying New York City residents with their drinking water, are expected to follow suit.

In 2009, a review of chemical use in fracking operations by the New York State Department of Environmental Conservation's Division of Mineral Resources listed 257 additives that may be mixed with the water injected into shale formations during the fracking process and provided a breakdown of the known chemicals—including carcinogenic chemicals—in those additives that stretched 10 pages long.⁶⁹

As of now, BC does not require disclosure of the chemicals used in the fracking process. However, that may soon change (see *Fracking Chemical Disclosure* below).

Provincial officials confirmed that natural gas companies would be free to apply to the federal government's hazardous materials information review commission to keep substances they consider to be trade secrets off of the database. Similar loopholes have become a source of controversy south of the border.

Fracking Chemical Disclosure: Coming Soon to BC?

At an energy industry conference in September 2011, BC Premier Christy Clark hailed a recent announcement by the Canadian Association of Petroleum Producers that natural gas companies were prepared to support the "voluntary disclosure" of chemicals used in hydraulic fracturing.⁷⁰

"My government applauds this move...and we're going to go a step further," the Premier said.⁷¹ "Soon, BC will launch an on-line registry that will disclose details about hydraulic fracturing and about the additives that are used."

"The information will be accessible to anyone who wants to see it," the Premier continued, saying the registry would be up and running by January, 2012. "It is time to show everyone how safely this business is done."

It remains to be seen how specific the information posted on the promised registry will be, with some expressing concerns that it might be quite generic in nature.

In an article posted to his news website, Public Eye, journalist Sean Holman reported shortly after Clark's announcement that provincial officials had confirmed to him that natural gas companies would be free to apply to the federal government's hazardous materials information review commission to keep substances they consider to be trade secrets off of the database.

Similar loopholes have "become a source of controversy south of the border," Holman noted, "where several states already have fracking fluid disclosure requirements. And it looks like that loophole is going to be controversial in British Columbia too."⁷²



PUBLIC HEALTH AND SAFETY

Public health and safety can be jeopardized by shale gas exploration and development, both above ground and below. Belowground, the biggest concern relates to how fracking activities can open up what might be described as contamination corridors, resulting in gas, toxified water and frack sand moving laterally from one well to another or vertically from the deep subsurface to the near subsurface, resulting in gas leaks or contamination of freshwater aquifers, as has been documented in studies of contaminated drinking water wells in parts of Colorado where fracking operations have occurred.⁷³ In the most worrisome of cases, the escaping gas may be sour gas (natural gas containing highly toxic hydrogen sulphide or H₂S).

In 2010, the BC Oil and Gas Commission issued a safety advisory in which it noted how frack sand had been blown from one wellbore into another 670 metres away. This was just one of 18 known “communication events” to have occurred between gas wells, in some cases spaced 750 metres apart.

A troubling potential outcome of such unwanted events is that they could become contributing factors to ultimately deadly sour gas leaks. In November 2009, for example, a 30,000 cubic-metre leak of sour gas at an Encana well site near the community of Pouce Coupe was ultimately traced to frack sand in the well, which corroded the well piping leading to a pipe break and the gas release. If frack sand were to be blown in sufficient volume into a producing sour gas well, a potentially deadly sour gas leak is one possible outcome.

Ultimately, to ensure public health and safety, wells being subject to hydraulic fracturing must be adequately spaced apart and properly developed at every stage of the process. Decisions on well density and well proximity to human populations must involve public health officials working on an equal footing with the energy regulator.

Liquid storage containers near a constellation of shale gas wells in the Farrell Creek area outside of Hudson’s Hope. Large amounts of chemicals, along with water, are pressure-pumped underground at fracking operations.

Conclusion and Recommendations

Given the obvious risks associated with accelerated shale gas developments, a suite of policy changes is needed to encourage more environmentally effective regulation of the industry.

BC'S SHALE GAS INDUSTRY IS EXPANDING in the absence of a vigorous public debate about what we as a province want, and it will likely undergo an even more rapid expansion in the event that gas prices climb and/or new markets emerge, such as the possibility of an expanded pipeline network, conversion facilities and tanker terminals to ship liquefied natural gas overseas.

Such developments will have significant implications for BC's economy, climate change objectives, public health and safety, and the sound management and protection of the environment, in particular water resources.

Given the obvious risks associated with accelerated shale gas developments, a suite of policy changes is needed to encourage more environmentally effective regulation of the industry. This includes pricing policies that encourage industry innovation, and many other changes to current rules and regulations.

To begin the necessary regulatory reforms, the provincial government should:

1. **PLACE CAPS ON ANNUAL NATURAL GAS PRODUCTION.** To manage renewable resources such as forests and fisheries on a sustainable basis, it is common practice to set legally enforceable maximum allowable harvests. In the absence of a cap, resources are unnecessarily and sometimes dangerously over-depleted. Capping exploitation of non-renewable resources such as natural gas ensures their more ordered development while also buying much-needed time to plan for the necessary transition away from their use. Failure to implement a cap courts the risk of a resource rush, which can cause serious harm to our environment and economy alike. Capping natural gas developments also gives the province a fighting chance of meeting its greenhouse gas emissions reduction targets. Moreover, it ensures that what gas does come out of the ground commands a higher price because there's less of it to go around. The longer the gas stays in the ground in a world running short of such resources the more valuable it becomes. Capping production further provides the space to determine whether or not the industry can move forward in a lower or ultimately zero-carbon way.



2. **DECLARE “NO-GO ZONES” WHERE GAS DEVELOPMENTS ARE PRECLUDED** out of a concern for other important resources such as water. This will further lower the emissions associated with an expanded industry, protect the environment and important public resources, and increase the dollar value of what gas is ultimately extracted. Ruling out immediate development in some undeveloped watersheds would be a reasonable starting point. Priority could then be given to monitoring hydrological processes in undeveloped watersheds and nearby watersheds undergoing development in order to gather important baseline information that guides future decisions on industrial water allocations.
3. **DECLARE A MORATORIUM ON SHALE GAS DEVELOPMENTS IN UNDEVELOPED WATERSHEDS** pending an independent panel review of hydrological data. By its own admission, BC’s energy industry regulator says that baseline data on water is missing over large areas of the province. To ensure that water resources are not irreparably harmed, the province should appoint an independent scientific panel of hydrological experts to assess the quality of information on surface and groundwater resources and rule on where industry developments should be precluded until proper baseline information is in place.
4. **END INDUSTRY SUBSIDIES** such as reduced royalty charges and infrastructure credits and immediately review royalty rates to ensure a fair return to the public as future gas production is ramped down. It makes little or no sense to subsidize the depletion of non-renewable resources in the first place, let alone in an environment of depressed prices. Ending subsidies increases the costs of doing business, but has the benefit of driving industry innovation and ensuring that finite, non-renewable resources are not developed prematurely. Higher royalty revenues can then be used to support a transition to increased production of renewable energy, which would support longer-term government income and greater employment.

Dusk approaches on Williston Reservoir, the largest hydroelectric reservoir in BC. Water and hydroelectricity in abundance will be needed to produce greenhouse gas-intensive shale gas in the years ahead.



5. **REQUIRE SHALE GAS COMPANIES TO CAPTURE AND STORE CO₂** at all proposed new gas treatment plants. This includes plants approved but not yet built and plants where expansions could take place. Without this requirement, as noted by Simon Fraser University's Mark Jaccard, the BC government cannot hope to meet its legislatively mandated greenhouse gas emissions reduction targets. A portion of reclaimed subsidies could be turned back to companies after they successfully completed construction of carbon capture and storage infrastructure. However, companies would then have to immediately invest at least a portion of those returned revenues to meet the following recommendation.
6. **FUND, ON A COST-SHARED BASIS, MONITORING OF CARBON CAPTURE AND STORAGE SITES** to ensure that stored greenhouse gases are not vented to the atmosphere. This is necessary for two reasons. The first is to ensure that the province continues to meet its obligations to reduce greenhouse gas emissions. The second is to ensure that carbon capture and storage can be done without environmental and public safety risk, and if it cannot, that it is immediately abandoned as a climate change strategy.
7. **LAUNCH AN EXPEDITED PROVINCIAL WATER CONSERVATION OR WATER PROTECTION PLAN.** This could be dealt with during the ongoing Water Act Modernization process. A credible, approved plan would include comprehensive groundwater legislation, which currently does not exist in BC.
8. **PUBLISH A NEW AND COMPREHENSIVE REVIEW OF BC'S GREENHOUSE GAS EMISSIONS.** This is vital to demonstrate that progress is being made to reduce overall emissions, and should include a projection of future emissions associated with an expanded shale gas industry, and a discussion of how the province will meet or exceed its legislated greenhouse gas emissions reduction targets while simultaneously promoting an expanded shale gas sector.
9. **CHARGE INDUSTRIAL WATER USERS HIGHER WATER-USE RATES.** Currently, shale gas companies pay zero dollars for all water used under water withdrawal permits granted to them by the provincial Oil and Gas Commission, and token charges of \$2.75 per Olympic swimming pool's worth of water under longer-term water licences. Higher prices for industrial water use will encourage conservation and other industry innovations noted elsewhere in this paper.
10. **MAKE THE SHALE GAS INDUSTRY AND OTHER INDUSTRIES PAY THEIR FAIR SHARE FOR HYDRO POWER.** With demands for power increasing in the province, BC Hydro has to develop or acquire new power. This carries a considerable cost. In its call for new energy supplies, the average price BC Hydro offered to pay was \$125 a megawatt hour. As an industrial customer, the shale gas industry will pay an average rate of only \$40 a megawatt hour. The loss incurred by BC Hydro (which must be paid for by its existing customer base) is over \$60 per megawatt hour. This constitutes a formidable subsidy to the shale gas sector, one that may be equal to or greater than its subsidized rights of access to public waters. The industry also hopes to benefit from a large subsidy in the form of new transmission lines. If the industry requires new electricity, it should pay fully for this need.
11. **PUBLICLY DISCLOSE ALL WATER LICENCE APPLICATIONS** and Section 8 water permit applications by the shale gas industry. At present, there is little by way of public notice on water licence and water permit applications, and what limited information is available is often not up-to-date and difficult to retrieve.

To manage renewable resources such as forests and fisheries on a sustainable basis, it is common practice to set legally enforceable maximum allowable harvests. In the absence of a cap, resources are unnecessarily and sometimes dangerously over-depleted.

12. **PUBLISH ALL WATER WITHDRAWALS FROM ALL WATER SOURCES** on a regularly updated database maintained by the province and available to the general public. A good model for this database would be the Harvest Billing System, maintained by the provincial Forest Service, which details all logs harvested from Crown and private forestlands in the province. The database should include: the name of the permit or licence holder, the approved water source, how much water by volume and date is removed from what water source, how much water by volume and source is injected underground and where, how much wastewater is produced at each fracking site, and where the wastewater is ultimately disposed of or reused. This database should include all traditional surface water sources such as reservoirs, lakes, rivers and creeks as well as unconventional surface source such as a borrow pits. All groundwater sources and withdrawals should be similarly reported.

13. **WORK WITH FIRST NATIONS TO DEVELOP A CLEAR, FAIR AND TRANSPARENT PROCESS** for consultation on natural gas industry water applications and approvals. Such a process must require water regulators to demonstrate how they have assessed or will assess the impacts on water resources, not just of individual water permits but the total number of existing or proposed permits and licences in a given watershed. Such a process should include adequate funding to ensure that First Nations either can have a hydrologist on staff to assess the impacts of proposed water licences and permits or can hire an independent expert on an as-needed basis.

14. **DEVELOP A CLEAR, FAIR AND TRANSPARENT CONSULTATION PROCESS** for the general public on all industrial water use applications of a certain magnitude. The Canadian Environmental Assessment Act and regulations could be a guide in this regard. Under CEEA regulations, any proposed groundwater taking of 200,000 cubic metres or more per annum can be subject to a federal environmental assessment, if the proposed activity occurs on lands under federal jurisdiction.

15. **ASSIGN ONE PROVINCIAL AGENCY TO BE RESPONSIBLE FOR ALL WATER ASSIGNMENTS.** This agency should have primary responsibilities for the environment, and should not be the energy industry regulator.

16. **APPOINT AN OFFICIAL INQUIRY UNDER THE HEALTH ACT** to address the health and safety risks associated with sour gas and hydraulic fracturing. The University of Victoria's Environmental Law Centre, on behalf of residents in BC's South Peace region, has already publicly advocated for an official inquiry to investigate sour gas. Given the expanding usage of fracking, such an inquiry should be expanded to address the additional public health and safety risks associated with fracking in sour gas zones.

17. **REQUIRE MINISTRY OF HEALTH OR MINISTRY OF PUBLIC SAFETY PERSONNEL TO REVIEW** and approve all proposed fracking operations that may potentially endanger public health and safety. Fracking activities in various locations in North America have been associated with potentially deadly sour gas leaks, contaminated surface waters, and contaminated drinking water wells. In many cases, these incidents occurred at operations sanctioned by energy industry regulators. A dual agency approval process should be required in cases where there is a reasonable expectation of a potential risk to public health and safety.



These recommended policies would ensure a higher level of environmental performance in an industry that is an increasingly major user of water and electricity resources while being a significant source of greenhouse gas emissions.



18. **REQUIRE THAT SHALE GAS COMPANIES SUBMIT FIVE-YEAR** and possibly 10-year development plans. Effective management of natural resources requires an understanding of industry intentions well before activities take place. In order for the public to have confidence that their air, water and land resources are being properly managed, regulators need good advance notice from natural gas companies about where they intend to situate future gas wells, how much water will be required to frack such wells, where the likely water sources for the fracking operations will be, and what the cumulative impacts of such activities are likely to be. With proper advance notice, provincial regulators would be better able to determine what the cumulative impacts on land and water resources would be and whether the appropriate baseline information was in place to make an informed decision on sustainable water use. Pre-development planning would also provide much-needed space for local communities and First Nations to participate more fully in resource planning.

Afternoon light shines on water, aspen and spruce forest near Fort Nelson, BC: a landscape that could soon be transformed forever by shale gas fracking operations in the nearby Horn River Basin.

These recommended policies would ensure a higher level of environmental performance in an industry that is an increasingly major user of water and electricity resources while being a significant source of greenhouse gas emissions.

However, a bigger task lies ahead. And that is how BC will wean itself off of dependency on fossil fuels—a challenge the province shares with every other jurisdiction on earth. Ultimately the province needs to enact policies that result in a steady ratcheting down in the use of non-renewable fossil fuels that are destabilizing the earth's climate, with a corresponding rise in the use of energy sources that do not pump ever more greenhouse gases into the atmosphere.

This is what ultimately makes environmental and economic sense. An economy—and the partial funding of cherished public programs including health care and education—predicated on the steady depletion of non-renewable, polluting fuels is not a recipe for future health and prosperity.

ENDNOTES

- 1 In testimony before the Canadian Parliamentary Standing Committee on Natural Resources on February 1, 2011, Antony Ingraffea, a leading expert on hydraulic fracturing at Cornell University, said: “The nature of the geology of shale is such that to produce the vast quantities of gas that are being forecast by the industry will require a very high well density compared to conventional gas development. By that I mean on the order of three wells per square kilometre.” He further testified that: “It takes between 50 and 100 times more fluids to develop a shale gas well than to develop a conventional gas well. That implies a concomitant amount of waste products is produced in the stream.”
- 2 Canadian Gas Association publications – www.cga.ca/publications/gasstats.htm. Not everyone believes that shale gas is as abundant as the Canadian Gas Association and others suggest. For example, Art Berman, a petroleum geologist with years experience working with PetroChina, Total and Schlumberger, has said that when all proven and probable technically recoverable North American natural gas sources are considered, there may be just 25 years supply, of which seven might come from shale sources. See Association for the Study of Peak Oil & Gas, 2010.
- 3 Charts 1.5 and 1.7 in the *B.C. Government Budget and Fiscal Plan, 2010/2011 – 2012/2013*, March 2, 2010.
- 4 Byfield, 2009. Under current regulations in BC, companies engaged in hydraulic fracturing operations can elect to treat wastewater that flows back to the surface at water treatment plants, although they are under no requirement to do so; if they do not treat it to a standard that it can be discharged to the environment and they elect not to re-use it, their only other legal option is to inject the waste water deep underground at approved injection sites.
- 5 U.S. Environmental Protection Agency, 2001.
- 6 Data supplied to the Canadian Parliamentary Standing Committee on Natural Resources by Encana Corporation.
- 7 National Energy Board, 2010.
- 8 Geoscience BC, 2011. The news release announces that over the next three years a jointly funded study by government and industry will focus on “collecting data on the quantity and quality of surface water sources in the Horn River Basin and assessing its availability for shale gas development.”
- 9 Even without considering the demand for additional electrical power from gas companies operating in the Horn River Basin, demand from gas companies operating in the more southern of BC’s two shale gas plays – the Montney Basin – might be sufficiently large enough to influence a decision on whether to proceed with the proposed Site C dam on the Peace River.
- 10 Business Council of British Columbia, 2008.
- 11 Ibid.
- 12 BC Ministry of Energy, 2009.
- 13 BC Ministry of Energy, 2008.
- 14 BC Ministry of Energy, 2009.
- 15 Campbell, 2011. The article provides a useful overview of industry perspectives on “government policies” that have made it attractive for energy companies to do business in BC’s shale gas zones. The article notes, for example, that in the U.S. energy companies with land tenures operate in a “use-it-or-lose-it” environment, which means that within three to five years of obtaining a subsurface lease to explore for and develop oil or gas resources they must demonstrate production or they forfeit their rights. “Not so in B.C., where firms have a five-year window to prove production on their leases” and are “then given 10 years to bring that production online.” The same article also notes that the industry is enamored with a “suite of industry friendly royalty programs to encourage development of unconventional gas resources,” the centerpiece of which is its Net Profit Royalty Program. Under the program, industry royalty payments to the province are just 2 per cent of gross revenues from shale gas production for the first 10 years of production or until all capital costs associated with development are paid off, whichever comes first.

Thereafter, royalty rates rise in tiers. The province also allows companies to claim for a credit to the royalties they would otherwise pay to the province for building roads, pipelines and other associated facilities.

- 16 Ebner, 2011.
- 17 Campbell, 2011.
- 18 For a useful guide on natural gas prices over time, see the Trading Economics website at www.tradingeconomics.com/commodity/natural-gas (accessed August 22, 2011). Prices quoted are in units of MMBtu or 1 million BTUs or British thermal units.
- 19 An MMBtu is a standard base measurement for gas and represents 1 million BTUs or British thermal units.
- 20 Kebede and McAllister, 2011. The authors note the strong demand for liquified natural gas or LNG, which is typically delivered by ocean tankers. LNG is natural gas that has been super-cooled to the point where the gas turns to a liquid. Upon arrival at LNG import terminals, the gas in liquid form is converted back to gas form. The article notes that "Japan's LNG imports rose 14.3 percent in July [2011] compared with the same period a year earlier as the nation continues to depend on the fuel to replace nuclear power lost due to the March earthquake, while South Korea's imports increased 9 percent year-on-year."
- 21 *The Economist*, "An unconventional glut: Newly economic, widely distributed sources are shifting the balance of power in the world's gas markets," March 11, 2010, at www.economist.com/node/15661889 (accessed August 22, 2011).
- 22 Simpson, 2011.
- 23 As reported on the Natural Gas Supply Association (NGSA) website NaturalGas.org, at www.naturalgas.org/environment/naturalgas.asp#emission (accessed August 23, 2011). Citing statistics from the U.S. Energy Information Administration, the NGSA reports that the pounds of CO₂ emissions per billion Btu of energy input show that natural gas's carbon dioxide emissions are 117,000 pounds, versus oil at 164,000 pounds and coal at 208,000 pounds.
- 24 For example, in March 2010, Colorado Governor Bill Ritter announced that the state would retire or retrofit up to 1,200 megawatts of coal-powered electrical generation. With that single decision, natural gas giant Encana noted, a significant amount of polluting coal technology would be retired and replaced by "clean" burning natural gas technology.
- 25 Howarth, Santoro and Ingraffea, 2011.
- 26 Similarly, in Canada, Encana lauded an announcement by Saskatchewan Power Corporation to purchase a guaranteed 20 years' supply of natural gas-fired electricity from the Northland Power Income Fund, calling it another significant step in the ascendance of natural gas as a cleaner alternative to coal. The decision, announced in February 2010, would result in the construction of a new 260-megawatt combined cycle electricity plant, marking another "great win for the natural gas industry in a province that currently generates 60 per cent of its electricity from coal," Encana said.
- 27 Ibid. The team further reported that: "over the 100-year frame, the GHG footprint is comparable to that for coal: the low-end shale-gas emissions are 18% lower than deep-mined coal, and the high-end shale-gas emissions are 15% greater than surface-mined coal emissions. For the 20-year horizon, the GHG footprint of shale gas is at least 50% greater than for oil, and perhaps 2.5 times greater."
- 28 Armendariz, 2009.
- 29 Levi, 2011.
- 30 National Energy Board, 2009.
- 31 Jaccard and Griffin, 2010. The authors note: "The B.C. government seeks to reduce provincial greenhouse gas (GHG) emissions 33% below their 2007 level by 2020. By 2050, it has committed to emissions that are 80% below their 2007 level. While pursuing these GHG emission targets, the government continues to promote the exploitation of highly valuable provincial natural gas resources in spite of the challenges this strategy creates for its GHG objectives."
- 32 Jaccard, 2006.
- 33 Jaccard and Griffin, 2010.
- 34 Ibid.
- 35 Horne, *Shale Gas in British Columbia*, 2011.
- 36 Matt Horne, personal communication, October 2010. This estimate assumes that most of the Cornell University findings on methane sources are captured in the province's current greenhouse gas inventory efforts and then extrapolates forward based on projections of

future gas production. The one factor from the Cornell study potentially not captured in current provincial inventory efforts is the issue of methane releases during well development and completion. The Cornell study assumes that all methane released during this phase of well production is not captured and the gas is flared. Flaring does not eliminate greenhouse gas emissions, but does mean that instead of raw methane being vented to the atmosphere, the gas is combusted and CO₂ – a less potent greenhouse gas – is emitted. There is uncertainty over exactly what level of flaring may occur during well development in BC.

- 36 Vanderklippe, 2011.
- 37 Parfitt, 2011.
- 38 BC Transmission Corporation, 2007.
- 39 BC Hydro, 2006.
- 40 BC Transmission Corporation, 2007. The document noted that: “Power quality is important in serving industrial loads in the oil and gas industry, as electric motors are affected by voltage fluctuations.” The same document also noted that by the end of 2007, the Buick Creek area would have been in critically short supply of available electricity because the “firm” power capacity at the closest substation in Fort St. John would have been exceeded in the winter of 2007.
- 41 BC Hydro, 2010.
- 42 Ibid. The document notes that by 2020, electricity demands in the Montney’s shale gas industry would be 2,101 gigawatt hours and in the Horn River Basin 1,061 gigawatt hours.
- 43 Bell, 2011.
- 44 BC Hydro, 2011.
- 45 Horne, 2011.
- 46 Bell, 2011.
- 47 Bains, 2010.
- 48 Horne, 2011.
- 49 Province of British Columbia, Bill 4, 2010.
- 50 Parfitt, 2010.
- 51 BC Oil and Gas Commission, 2011.
- 52 BC Oil and Gas Commission, *Quarterly Reports on Short-Term Water Approvals and Use*, January to March 2011 and April to June 2011.
- 53 Ibid.
- 54 BC’s Water Licences Query database is accessible at http://a100.gov.bc.ca/pub/wtrwhse/water_licences. input. To arrive at the tally, the database was searched in several ways, including by individual companies operating in BC’s natural gas sector and by proposed water use or “purpose.”
- 55 The water licence issued to Talisman Energy by the Ministry of Forests, Lands and Natural Resource Operations on July 25, 2011 notes as one of its conditions that the licence will “remain in good standing as long as the agreement between the British Columbia Hydro and Power Authority and Talisman Energy Inc. as holder of the appurtenant leases and licences is active and in good standing.” The terms and conditions of the agreement between the power utility and the natural gas company have not been publicly disclosed, leaving open questions about whether or not Talisman may have to compensate BC Hydro for any foregone power production as a result of Talisman’s water withdrawals.
- 56 While members of the public have been largely kept out of the loop in commenting on proposed water withdrawals by natural gas companies, in specific cases such as the proposed (and subsequently approved) water licences at Williston Lake, the natural gas companies applying for the licences were required to meet with BC Hydro before the provincial water regulator issued the licences because of BC Hydro’s previously approved rights of access to water from the reservoir.
- 57 British Columbia’s Environmental Assessment Act lists as “reviewable” any new well or grouping of wells “designed to be operated to extract ground water at the rate of 75 litres or more per second.” For more information, see www.env.gov.bc.ca/wsd/plan_protect_sustain/groundwater/library/gws_eao.html.
- 58 The Canadian Environmental Assessment Act’s Comprehensive Study List Regulations require that any proposed withdrawal of 200,000 cubic metres or more per year from a groundwater source underlying lands under federal jurisdiction could be subject to a federal environmental assessment review.

- 59 Auditor General of British Columbia, 2010. In the news release, Auditor General John Doyle said: "One million British Columbians are estimated to rely on groundwater for daily use, and this demand is increasing. The government must put in place an appropriate framework to manage this precious resource sustainably."
- 60 Written correspondence between BC's Oil and Gas Commission and the Fort Nelson First Nation in 2010 and 2011 reveals that in one hydraulic fracturing operation involving the use of approximately 900,000 cubic metres of water, roughly 45 per cent of all the water used came from unpermitted sources, specifically borrow pits. Other untracked water sources include water obtained by energy companies from landowners.
- 61 A January 24, 2011 letter to Lana Lowe, Lands Director of the Fort Nelson First Nation, from Tom Ouellette of the Oil and Gas Commission notes that of the 980,000 cubic metres of water used by Apache at its record-setting Two Island Lake fracking operation, 431,000 cubic metres, or 44 per cent of all the water used, had accumulated in borrow pits during the 2009 and 2010 freshet periods.
- 62 BC Oil and Gas Commission, "Changes in Section 8 Short Term Water Use Approvals," Directive 2011-02, March 2, 2011.
- 63 Consultation Process Agreement Between Her Majesty the Queen in Right of the Province of British Columbia as represented by the Minister of Energy, Mines and Petroleum Resources and by the Oil and Gas Commission ("British Columbia") and Fort Nelson First Nation, December 1, 2006.
- 64 Ibid.
- 65 Holman, "Former regulator's new job with company raises public interest concerns," 2011.
- 66 BC Oil and Gas Commission, "First Nations Consultation on Short Term Use of Water Applications," 2011. This directive notes that the Oil and Gas Commission "will now be consulting with applicable First Nations on all applications for short term water use that may potentially affect rights recognized and affirmed by Section 35(1) of the Constitution Act, 1982. However, the OGC notes in the same directive that it does not intend to fully consult with First Nations on all such applications. If the proposed water withdrawal rate is less than 500 cubic metres per day, the OGC intends to treat such applications as "information only" referrals. Only those permits with proposed diversion rates of over 500 cubic metres per day will require "notification" with an "opportunity to comment" provided to First Nations.
- 67 Letter to the Fort Nelson First Nation from Front Counter BC, May 27, 2010, subject line: *Referral: Application for a Water Licence in the vicinity of Fort Nelson River.*
- 68 Ibid.
- 69 New York State Department of Environmental Conservation Division of Mineral Resources, 2009.
- 70 The disclosure that Clark referred to was contained in a set of "guiding principles" released by the Canadian Association of Petroleum Producers on September 8, 2011 (see CAPP news release "CAPP members establish new Guiding Principles for Hydraulic Fracturing" at www.capp.ca/aboutUs/mediaCentre/NewsReleases/Pages/GuidingPrinciplesforHydraulicFracturing.aspx#fRbXvi4n6qmD (accessed October 7, 2011)). CAPP's actual chemical disclosure commitment reads as follows: "We will support the disclosure of fracturing fluid additives." CAPP makes no comment about the forum in which it thinks such disclosure should occur.
- 71 Excerpts from Premier Christy Clark's speech, from an on-line video at www.youtube.com/watch?v=vFhS8dJuQnw&feature=player_embedded (accessed October 7, 2011).
- 72 Holman, "Opacity part of new transparency for gas industry," 2011.
- 73 In 2008, analysis of contaminated water in water wells in Garfield County in Colorado revealed the presence of "thermogenic" methane. Methane contamination of water wells is not uncommon and when it occurs it typically involves "biogenic" or near-surface methane gas. Through isotopic testing of the methane in a number of contaminated water wells in the region, where a lot of fracking operations had occurred, it was determined that the methane was from deeper zones and therefore thermogenic gas. This was a strong indication, the research concluded, that the wells were contaminated with gas from "petroleum-related sources, not shallow natural methane." The findings are outlined in Geoffrey Thine, *Review of Phase II Hydrogeologic Study Prepared for Garfield County*, December 20, 2008.

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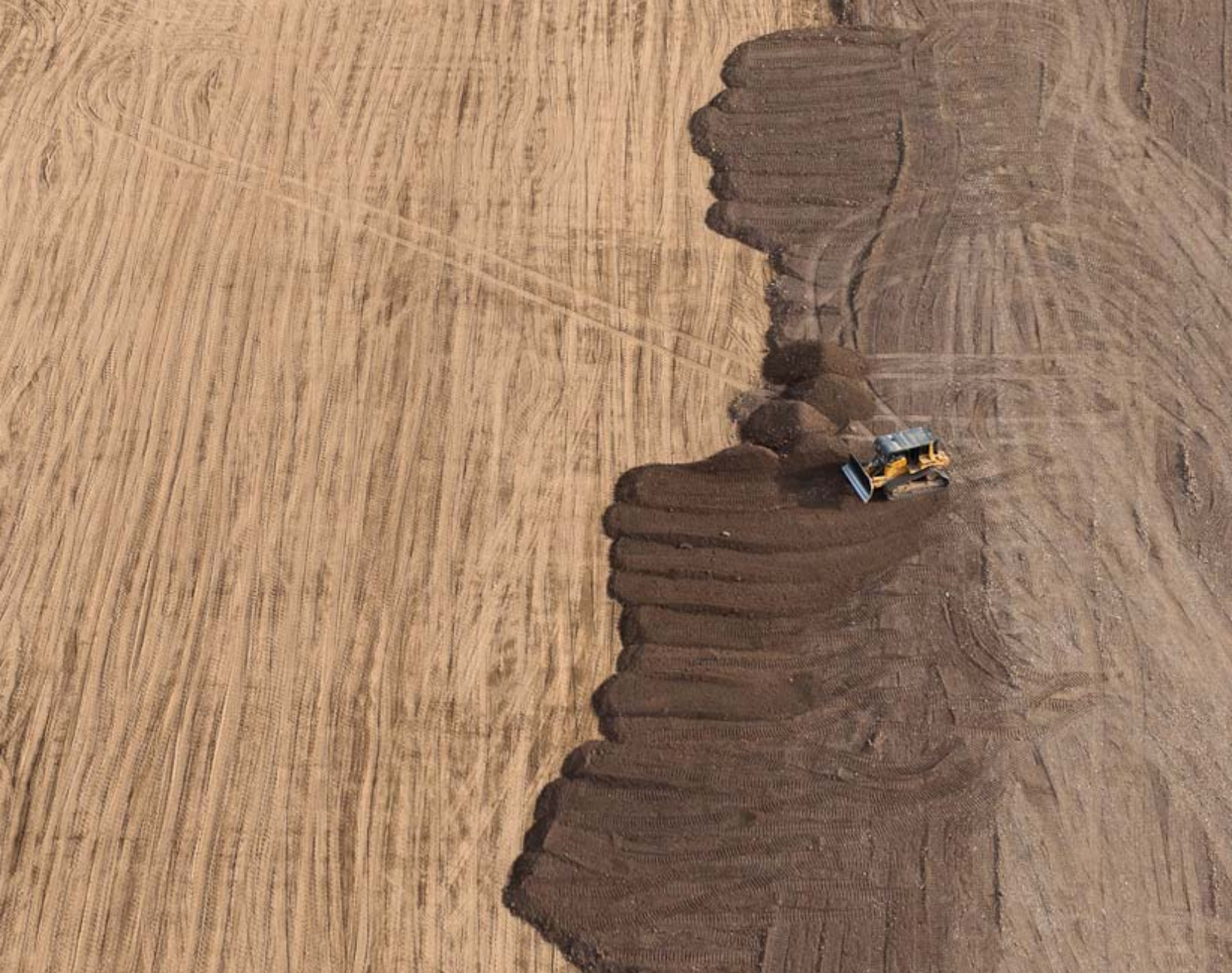
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Back cover: A bulldozer clears a new multi-well shale gas pad prior to fracking operations in the Farrell Creek operating area near the community of Hudson's Hope.



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1400—207 West Hastings Street
Vancouver, BC V6B 1H7
604.801.5121
ccpabc@policyalternatives.ca

www.policyalternatives.ca



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PO Box 2205, Station Terminal
Vancouver, BC V6B 3W2
604.683.8220
info@wildernesscommittee.org

www.wildernesscommittee.org

THE CLIMATE JUSTICE PROJECT

The Climate Justice Project is a multi-year initiative led by CCPA and the University of British Columbia in collaboration with a large team of academics and community groups from across BC. The project connects the two great "inconvenient truths" of our time: climate change and rising inequality. Its overarching aim is to develop a concrete policy strategy that would see BC meet its targets for reducing greenhouse gas emissions, while simultaneously ensuring that inequality is reduced, and that societal and industrial transitions are just and equitable.