Is natural gas a climate change solution for Canada?

the PEMBINA institute
Sustainable Energy Solutions

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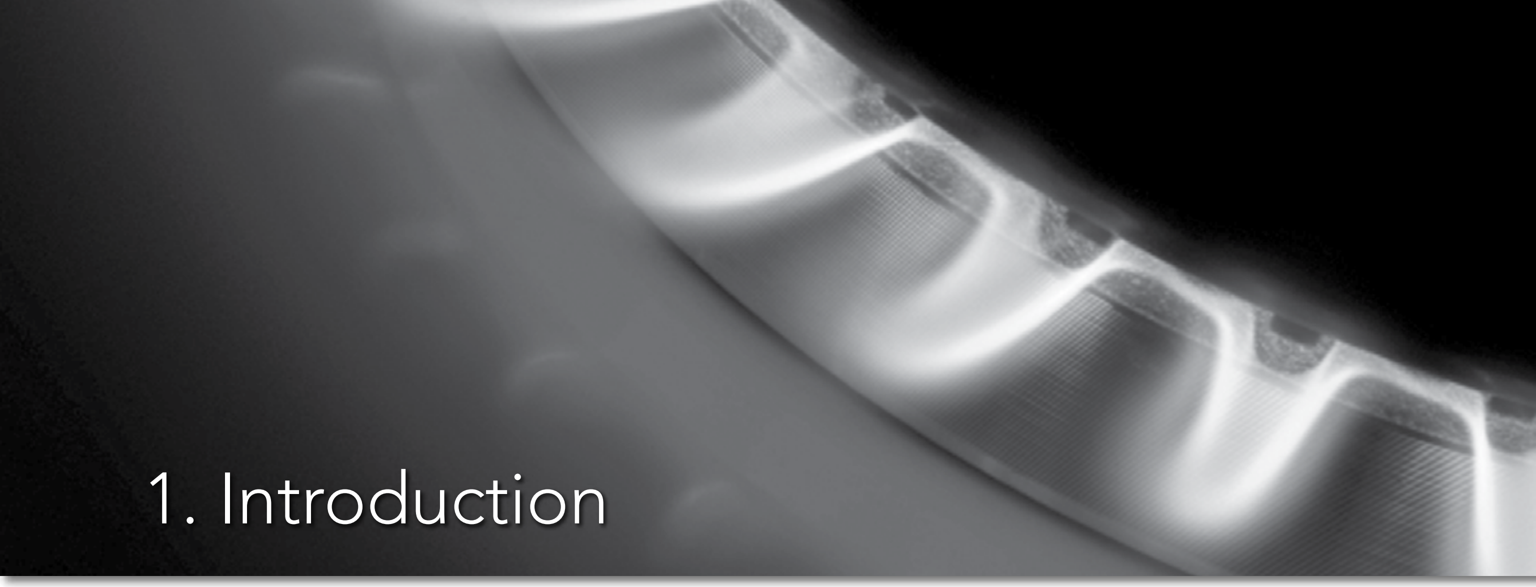


1. Introduction

1.1 Research context and questions

Natural gas is and will continue to be a high-profile energy source in Canada and globally. While Canada is the world's fifth biggest producer of energy overall,[1] it is the world's third biggest producer of natural gas.[2] The country has produced more natural gas in the past two decades than any other form of energy.[3] In 2008, 40 per cent of the primary energy[4] produced in Canada was natural gas, and 59 per cent of that gas was exported by pipeline to the U.S.,[5] earning $33 billion of revenue for Canadian producers.[6]

While conventional gas production in Canada is now in decline, new and abundant sources of "unconventional gas" – such as shale gas – have reinvigorated the sector in spite of low prices. The newly increased supply of natural gas has prompted greater discussion about the role gas could play in a world that is transforming its energy system. Supporters of natural gas often portray it as a "bridging" fuel that enables near-term reductions in the greenhouse gas (GHG) emissions responsible for climate change. But in the face of intensified efforts by producers to explore for and increase production of natural gas, there has been a lack of clear analysis of how gas fits into the evolution of energy production in Canada in light of the need for deep GHG reductions by 2050.

Does a "bridging" role for natural gas stand up to scrutiny? For instance, might improvements in energy efficiency avoid the need to use more natural gas, even if there is a delay in moving to large-scale non-fossil energy? Could investing in long-lived natural gas infrastructure leave us "locked in" to that energy source, creating a barrier to moving to deeper GHG reductions? Or would power producers willingly accept the retirement of gas-fired plants after a couple of decades? Is the urgency of cutting GHG emissions such that we should move very quickly to end the burning of all fossil fuels? Or might continued combustion of natural gas with carbon dioxide (CO_2) capture and storage (CCS) remain viable?

These questions about the role of natural gas in fighting climate change are made even more important by growing concerns about the non-climate environmental impacts of the new kinds of natural gas production (and use). The proposed Mackenzie Gas Project would be the biggest industrial development ever in Canada's Arctic.[7] Unconventional gas production in British Columbia may be a significant threat to water resources.[8,9] Ever greater amounts of natural gas are fuelling high-impact oil sands operations in Alberta. Controversy over the costs and benefits of establishing a major shale gas industry in Quebec has recently been dominating headlines there.

This report aims to explore the role of Canada's federal and provincial governments in shaping future production and use of natural gas in consideration of both the climate and non-climate environmental impacts. The report explores three linked questions, different answers to which could have very different consequences for government policies. This analytical framework is depicted in Figure 1 below. It makes the following key assumptions regarding trade and policies:

- **Trade**: Because the Canadian and U.S. natural gas markets are tightly linked, the two countries need to be analyzed together. We do not, however, consider Mexico; although the U.S. trades natural gas with Mexico, the volumes have been very small to date (in 2008, net U.S. imports from Canada were 13 per cent of consumption, while net exports to Mexico were only 1.3 per cent of consumption[10]). Accordingly, in this report we will use the term "North America" to refer only to the U.S. and Canada. We also assume, based on current information (see Sections 1.3 and 3.2), that liquefied natural gas (LNG) trade between North America and the rest of the world will not become a major factor in North American production decisions, which means that our production of natural gas should align closely to our consumption.
- **Policies**: If the non-climate environmental impacts of natural gas production can be contained at an acceptable level, then the best guide to the optimal path for natural gas production and use is the expected outcome of well-designed climate policies[11] that explicitly aim to achieve the necessary scale of GHG reductions in Canada. In the near term, governments will not necessarily announce and implement such policies. But if natural gas production strays from our best estimate of the optimal path, it will be more difficult and costly to implement adequate climate policies later on. Therefore, in the absence of adequate climate policies at the outset, we should be prepared to rely on other policies, including approvals of new production facilities, to follow our best estimate of the optimal path.

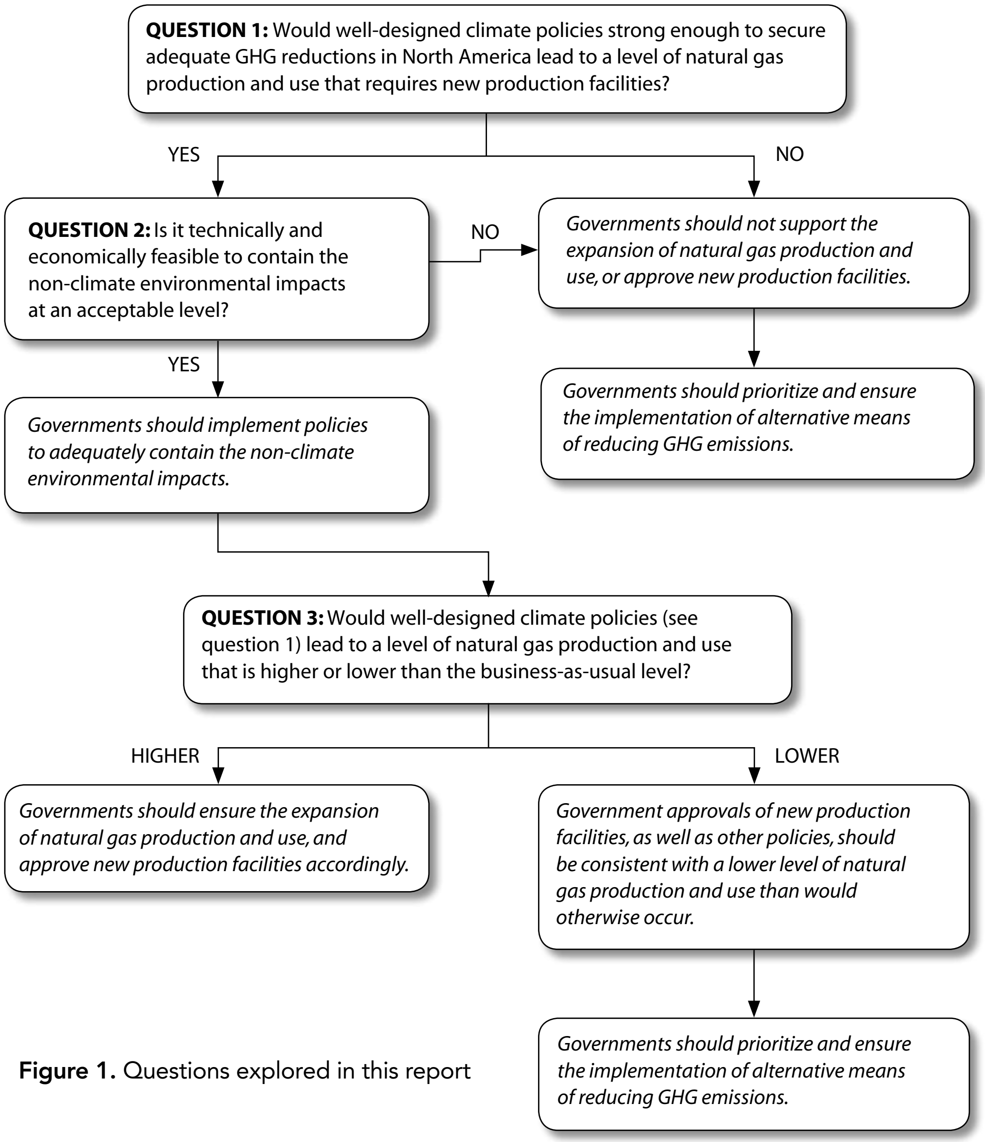


Figure 1. Questions explored in this report

1.2 Natural gas supply

The so-called "unconventional gas revolution" has raised expectations that natural gas will play an even greater role in Canada's energy future than it does now. In the past few years producers have developed technology capable of producing large volumes of gas from shale and other low-permeability rock formations at relatively low cost. This has "completely transformed the North American gas supply and price picture,"[12] to the point where Canada's natural gas resource has expanded to well over 100 years of supply at current rates, and

North America has about 40 years of profitable supply at mid-2010 prices.[13] (Those prices were low compared to recent years.)

New sources of unconventional gas, initially from British Columbia, possibly later from Alberta and Quebec – plus "frontier" gas from the Northwest Territories – could more than compensate for the steady decline in production of conventional natural gas from Western Canada. Some projections show these two trends merely cancelling one another out,[14] but the Canadian Association of Petroleum Producers is now forecasting a more rapid expansion of unconventional gas – particularly gas produced from shale – resulting in about a 15 per cent increase in total Canadian natural gas production between 2008 and 2020.[15]

1.3 Natural gas demand

It is not clear, however, that the demand will exist for large increases in production. The National Energy Board forecasts an 18 per cent increase in Canada's consumption of natural gas between 2008 and 2020 (as part of a 13 per cent increase in the country's total energy consumption) if there are no changes to the slate of government programs currently in place.[16] But the Canadian and U.S. natural gas markets are very tightly linked, with the U.S. market by far the larger, which means that Canadian production volumes are determined by U.S. demand even more than by Canadian demand. Under the same "business-as-usual" conditions, the U.S. Department of Energy forecasts a nine per cent increase in U.S. natural gas consumption between 2008 and 2020, but only a two per cent increase in the following decade.[17]

Globally, the International Energy Agency (IEA) forecasts a 43 per cent increase in natural gas consumption between 2008 and 2030, as part of a 38 per cent increase in total energy consumption, under its own business-as-usual "current policies" scenario.[18] North American producers could potentially help meet some of this demand by starting to export significant amounts of LNG to the rest of the world. However, such exports would face many hurdles, including competition from other suppliers and uncertainty about the future prices in destination countries needed to support the high capital costs of LNG infrastructure.[19] We discuss the prospects for LNG exports in more detail in Section 3.2.

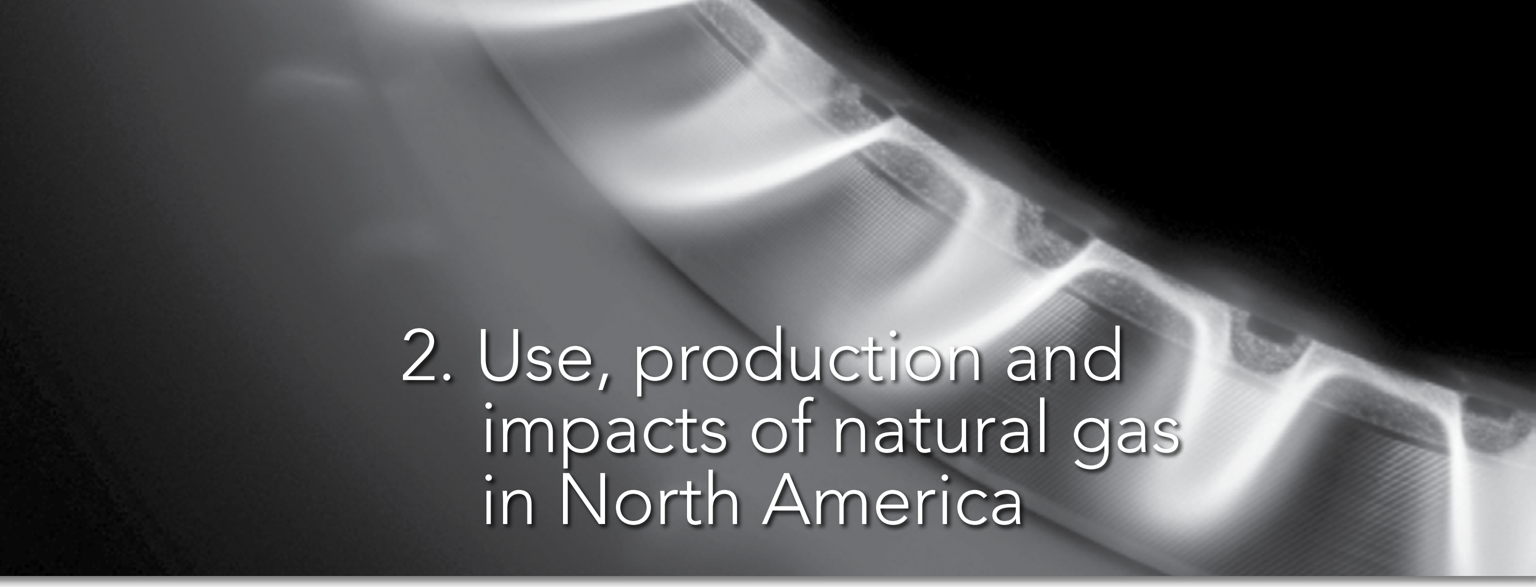
1.4 Natural gas in a carbon-constrained future

Importantly, however, the international community has recognized that business-as-usual is not an option: the world needs to transform its energy system because of climate change. The IEA itself warns that business-as-usual, continued to 2100, would result in around 6°C of global warming, and that the consequences of this would be "very severe."[20] This places a big question mark over natural gas. It is a carbon-based fossil fuel, which means that burning it produces CO_2, the main GHG responsible for climate change.

It is true that natural gas, being composed essentially of methane (CH_4), contains the least carbon of all the fossil fuels – much less than coal, and also less than oil. So replacement of coal and oil by natural gas will reduce CO_2 emissions. Replacing all coal and oil by natural gas would reduce CO_2 emissions from burning fossil fuels (71 per cent of Canada's total GHG emissions) by about one-fifth in Canada[21] and about one-third in the U.S.[22] Those reductions, however, would only be relative to a rising business-as-usual level of emissions. Also, large-scale replacement of oil by natural gas in transportation faces many obstacles (see Section 3.4.1). Replacement of coal by natural gas in electricity generation alone would be relatively straightforward, given the advanced age of many coal-fired plants;[23] it would reduce CO_2 emissions from burning fossil fuels by about one-10th in Canada and one-fifth in the U.S., again relative to a business-as-usual level.[24]

However, G8 heads of government have agreed – based on scientific analysis of what would be needed to avoid the worst of climate change – that developed countries must reduce their total GHG emissions by 80 per cent or more by 2050, relative to a fixed recent level.[25] So while replacement of coal by natural gas in electricity generation could potentially make a significant contribution to meeting the near-term national GHG targets to which both Canada and the U.S. have committed (17 per cent below the 2005 level by 2020),[26] it would not come close to achieving the emission reductions needed by 2050. (Another concern, discussed in Section 2.4, is that emissions of methane – itself a powerful GHG – during the lifecycle of natural gas may be considerable.)

Thus, supporters of natural gas portray it as a bridging or "transitional" fuel that can help reduce emissions in the early stages of a long-term shift to emissions-free energy.[27] It is widely agreed that this shift will need to be driven mainly by a gradually increasing price on GHG emissions (a "carbon price"), established by a cap-and-trade system and/or a carbon tax. An initial, modest carbon price might perhaps be enough to make natural gas more economic than coal for electricity generation, but not to make large-scale renewable (or nuclear) energy consistently more economic than natural gas. In this scenario, natural gas would help achieve significant near-term emission reductions at modest cost, while a higher carbon price would only eliminate gas from the picture later on. Indeed, early replacement of coal by natural gas in electricity generation could be achieved through regulated performance standards, with no need to wait for governments to implement carbon-price policies. We examine these issues in Section 3.



2. Use, production and impacts of natural gas in North America

2.1 Use

Natural gas is the second biggest source of primary energy consumed in North America, representing just under one-third of primary energy consumed in Canada, and one-quarter in the U.S. (Petroleum is the biggest source of primary energy consumed; see Table 1.)

Table 1. Sources of primary energy consumed[28] in Canada and the U.S. in 2008

SOURCE	CANADA[29]	U.S.[30]	CANADA+U.S.
Petroleum[31]	43%	43%	43%
Natural gas	31%	25%	26%
Coal	11%	23%	22%
Non-fossil electricity	14%	4%	5%
Biomass	–[32]	4%	4%[33]

More than half of the natural gas consumed in Canada is used to generate heat and power in industry, and another third to heat buildings. Less than one-10th is used to generate electricity. In comparison to Canada, industry in the U.S. represents a much smaller proportion of natural gas consumption, buildings about the same proportion, and electricity generation a much larger proportion. The biggest reason for these differences is hydroelectricity's much greater role in Canada than in the U.S. (See Table 2.)

Table 2. Uses of natural gas consumed in Canada and the U.S. in 2008

USE	CANADA[34]	U.S.[35]
Industry[36]	60%	38%
Residential buildings	19%	20%
Commercial/institutional buildings	14%	13%
Electricity generation	7%	28%
Road transportation	0.05%	0.12%

All fossil fuels are subject to large price fluctuations over time, but the use of natural gas is especially sensitive to price fluctuations, for two reasons. First, equipment to burn natural gas is inexpensive relative to the fuel itself. For example, while the costs of generating electricity from new coal- and natural gas-fired plants are similar, they are dominated by capital costs in the case of coal, and fuel costs in the case of natural gas.[37] Second, natural gas can be relatively easily replaced by other energy sources in industry, buildings and electricity generation. This contrasts with petroleum, which is mostly used in transportation where alternatives are not yet widely commercialized.

It should be noted that natural gas can have operational advantages over the alternatives. For instance, natural gas-fired turbines have the advantage of being able to quickly adjust their power output. This means that in electricity grids that lack other "on demand" sources like hydropower, gas-fired plants play an important role of following fluctuations in daily electricity consumption patterns, as well as complementing variable-output sources like wind power.

The large fluctuations in prices, and the sensitivity of use to those fluctuations, mean that forecasts of the future use of natural gas are subject to considerable uncertainty. Figure 2 shows that annual average U.S. wellhead prices have varied by nearly a factor of four over

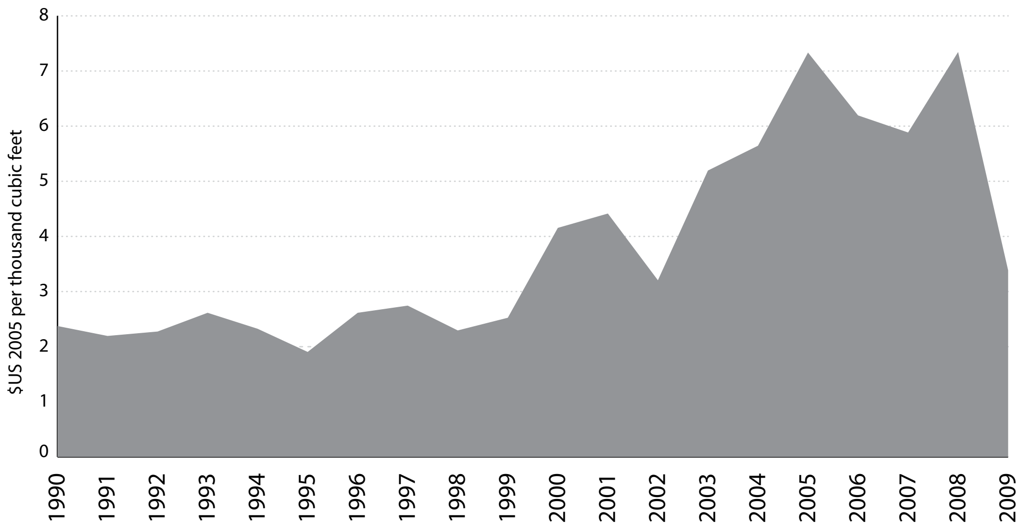


Figure 2. Annual average U.S. natural gas wellhead prices, 1990–2009[38]

the past two decades. The sharp rise from 1999 to 2005–08 was a result of the decline of conventional natural gas production at a time when the size of unconventional resources was not yet understood.[39] Canadian prices are closely tied to U.S. prices.

The uncertainty inherent in forecasts of natural gas use should be borne in mind when considering Table 3, which summarizes the most recent versions of two leading national forecasts – those by Canada's National Energy Board and the U.S. Department of Energy. Both are for business-as-usual "reference case" scenarios in which there are no changes to the slate of government programs currently in place.[40,41] In Canada, consumption of natural gas is projected to increase somewhat faster than overall energy consumption, with a major contributing factor being expansion of oil sands production.[42] Consumption of natural gas is also projected to increase faster than overall energy consumption in the U.S. until 2020, with industry in general accounting for the bulk of the increase in gas use;[43] but gas consumption is projected to be nearly flat in the subsequent decade. Both forecasts project significant improvements in energy efficiency, with total energy consumption growing much more slowly than GDP (GDP is projected to grow in both countries by over 30 per cent between 2008 and 2020[44]).

Table 3. "Business-as-usual" evolution of natural gas consumption in Canada and the U.S.

		CANADA[45]	U.S.[46]	CANADA+U.S.
Natural gas share of primary energy consumption	2008	30%[47]	26%[48]	26%
	2020	31%	27%	28%
	2030	–	26%	–
Growth in consumption 2008–20	Natural gas	18%	9%	10%
	Total primary energy	13%	3%	5%
Growth in consumption 2008–30	Natural gas	–	11%	–
	Total primary energy	–	10%	–

2.2 Production

While petroleum is the biggest source of primary energy *consumed* in North America, natural gas is the biggest source of primary energy *produced* here – this difference being due to the large U.S. imports of oil from other continents. In Canada, natural gas and petroleum were in a virtual tie as largest sources of primary energy produced in 2008. (See Table 4.)

Table 4. Sources of primary energy produced[49] in Canada and the U.S. in 2008

SOURCE	CANADA[50]	U.S.[51]	CANADA+U.S.
Natural gas	40%	32%	33%
Coal	9%	36%	31%
Petroleum[52]	41%	20%	24%
Non-fossil electricity	10%	6%	7%
Biomass	–[53]	6%	5%[54]

As noted in Section 1.1, in 2008, 59 per cent of the natural gas produced in Canada was exported by pipeline to the U.S.[55] Taking into account imports back into Canada, net exports from Canada to the U.S. were 50 per cent of Canada's production,[56] or 13 per cent of U.S. consumption.[57]

The "reference case" National Energy Board and U.S. Department of Energy forecasts (see Section 2.1) anticipate, respectively, a three per cent decline in Canada's natural gas production between 2008 and 2020,[58,59] but a 15 per cent increase in U.S. production over the same period.[60] The U.S. forecast foresees production increasing much more slowly after 2020, giving an overall 24 per cent increase from 2008 to 2030[61] (the Canadian forecast ends in 2020). The two forecasts agree that with Canadian consumption increasing (see Table 3 above) while production falls slightly, Canadian natural gas exports to the U.S. will decline by about one-third between 2008 and 2020.[62] Canada is also projected to start importing modest amounts of LNG[63] (in fact, Canada's first LNG import terminal began operations in 2009[64]).

Underlying these projections is a major shift in natural gas sources and extraction technology. In both Canada and the U.S., extraction of "conventional" natural gas is in long-term decline, while production of "unconventional" gas is increasing, and "frontier" gas production in remote locations is also projected to expand. While forecasts of natural gas *consumption* are subject to considerable uncertainty because of sensitivity to price fluctuations, uncertainty in forecasts of natural gas *production* is heightened by the development of new production regions and technology. This is illustrated by the contrast between the forecasts of the National Energy Board – which projects a decline in Canadian production between 2008 and 2020 – and of the Canadian Association of Petroleum Producers (CAPP), which projects about a 15 per cent production increase over the same period, based on a more rapid expansion of unconventional gas.[65] CAPP's forecast must, of course, be considered in the context of the organization's vested interest in expanding production.

2.3 Shift to frontier and unconventional gas

It is important to examine the characteristics of unconventional and frontier gas because they present significantly greater environmental risks than the conventional gas that they are replacing:

- **Conventional natural gas** is contained in spaces in permeable rock formations in readily accessible locations on land, and can typically be extracted by drilling down vertically. "Solution gas," produced as a by-product of crude oil production, is also commonly included in the category of conventional natural gas.
- **Frontier gas** is extracted from more remote regions with more challenging – and therefore more risky – operating environments and the need for special infrastructure to bring the gas to market. The National Energy Board designates all production in coastal waters and north of the 60th parallel as frontier production.[66] This includes production offshore from Nova Scotia and the proposed Mackenzie Gas Project. In the U.S., the term would include Alaskan gas.
- **Unconventional gas** is contained in spaces in low-permeability rock formations and/or bonded ("adsorbed") to surfaces within them. To extract the gas in commercial volumes, producers typically need to drill numerous horizontal wells within the rock and inject high-pressure fluids to fracture it ("hydraulic fracturing" or "fracking"). Multiple wells can be drilled from a single "drill pad" to limit the disturbance to the land surface.

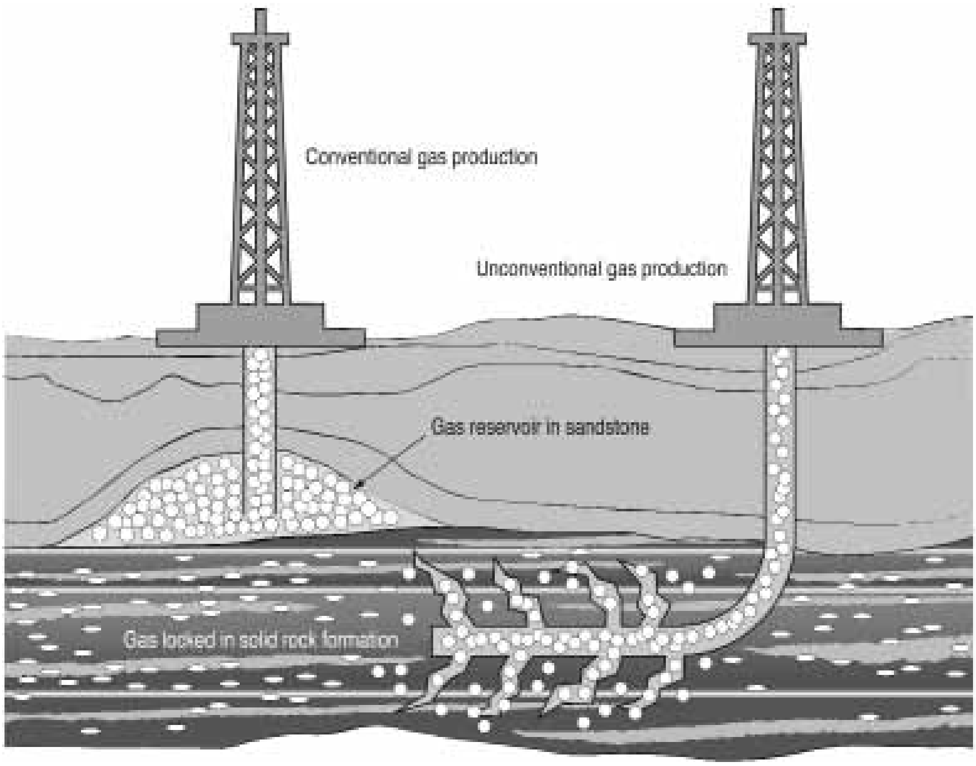


Figure 3. Conventional versus unconventional gas extraction

Although hydraulic fracturing has been used for decades, producers only began combining it with horizontal drilling to exploit unconventional gas resources – notably, vast shale deposits – as recently as 2002–03, initially in Texas.[67] Deployment of this technology has since expanded quickly, especially under the stimulus of high natural gas prices during 2005–08. This is commonly described as the "unconventional gas revolution," which, as noted in Section 1.2, has "completely transformed the North American gas supply and price picture."[68] Canada's natural gas resource (estimated recoverable marketable gas) is now well over 100 years of supply at current rates, and it is dominated by unconventional gas.[69] North America has about 40 years of profitable supply at mid-2010 prices,[70] which were low compared to recent years (although they have since fallen further).

Three types of unconventional gas are now being produced:[71]

- **Shale gas** – as its name indicates – is found in shale, a fine-grained rock formed from ancient deposits of mud. The main Canadian gas shales are in Northeast British Columbia (Horn River and Montney shales), in southern Alberta and Saskatchewan (Colorado shale), the St. Lawrence valley in Quebec (Utica shale), and in Nova Scotia and New Brunswick (Horton Bluff shale).[72] The Quebec and U.S. deposits also extend into southern Ontario.[73] Production is now increasing rapidly in British Columbia, while extensive exploration is underway in Quebec.
- **Tight gas** is similar to shale gas in that the gas is held tightly in rock formations, but in this case the rock is not shale. There is no clear definition of tight gas in Canada, and there can be some overlap between conventional and tight gas, and between tight gas and shale gas. For example, the Montney deposit in British Columbia is variously described as shale gas and tight gas.[74] Tight gas is found in various locations in Western Canada.
- **Coalbed methane** is natural gas present in coal seams. It is found in Western Canada and in Nova Scotia.[75]

Figure 4 depicts the different contributions of conventional, frontier, shale and tight gas, plus coalbed methane, to Canadian production since 2000 as well as to future production

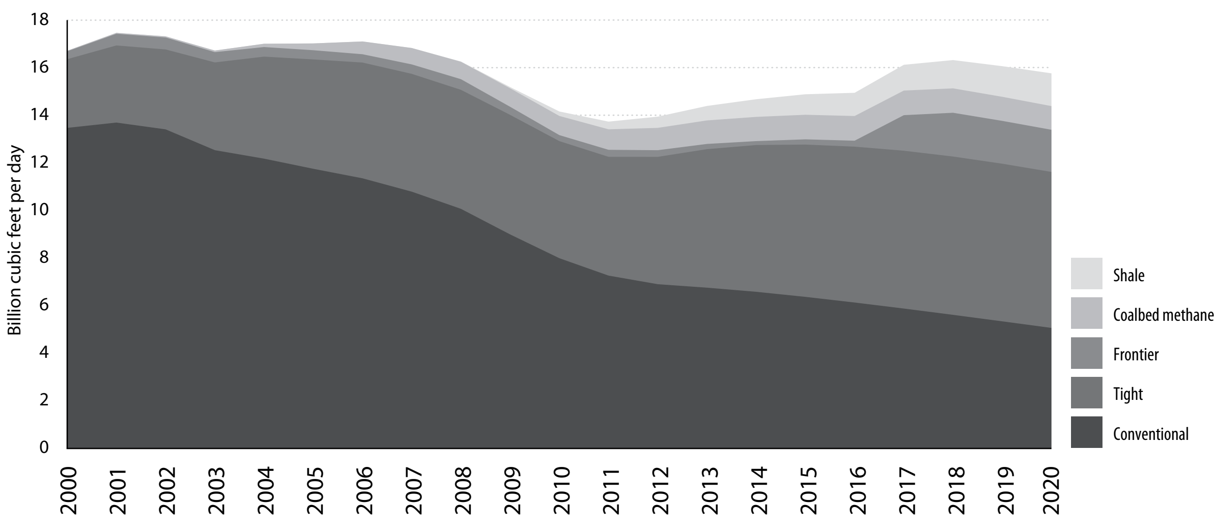


Figure 4. National Energy Board projection of types of gas production in Canada[76]

according to the National Energy Board's reference case forecast. The figure shows clearly the shift from conventional to unconventional and frontier gas. The picture in the U.S.[77] is quite similar, with one key difference being that shale gas development is further advanced there.

2.4 Greenhouse gas emissions

Natural gas is composed essentially of methane (CH_4), and therefore produces CO_2 when it is burned for energy. However, combustion of natural gas produces considerably less CO_2 per unit of usable energy than combustion of other fossil fuels like coal or petroleum products. This is because natural gas contains less carbon than other fossil fuels, and also because natural gas combustion devices tend to be more energy efficient (they waste less of the energy in the fuel) than devices that burn other fuels. Table 5 illustrates this by comparing the performance of recent pulverized coal and natural gas combined cycle[78] power plants (the types of plants that currently dominate new electricity generation using the two fuels).

Table 5. Comparison between coal and natural gas for electricity generation[79]

	PULVERIZED COAL	NATURAL GAS COMBINED CYCLE
Energy efficiency	40–43%	50–53%
CO_2 emissions (kg/MWh)	722–941	344–364
SO_2 emissions (ng/J)	198–1,462	0–0.7
NO_x emissions (ng/J)	219–258	5
PM_{10} and $PM_{2.5}$ emissions (ng/J)	15–30	2

NOTE: energy efficiency is expressed relative to the higher heating value; emissions are from combustion only, not production of the fuel.

However, while replacement of coal and oil by natural gas will reduce CO_2 emissions, emissions from natural gas combustion remain very significant. As noted in Section 1.4, replacing all coal and oil by natural gas would reduce CO_2 emissions from burning fossil fuels (71 per cent of Canada's total GHG emissions) by only about one-fifth in Canada and about one-third in the U.S., relative to a rising business-as-usual level of emissions; replacement of coal by natural gas in electricity generation alone would reduce CO_2 emissions from burning fossil fuels by about one-10th in Canada and one-fifth in the U.S. (again relative to a business-as-usual level). This could potentially make a significant contribution to meeting the near-term national GHG targets to which both Canada and the U.S. have committed, but would not come close to achieving the 80 per cent-plus reductions in developed countries' GHG emissions (relative to a fixed recent level) that G8 heads of government have agreed are needed by 2050, based on scientific analysis of what would be needed to avoid the worst of climate change.[80]

Environment Canada estimates indicate that CO_2 emissions from using natural gas as an end product represent about four-fifths of the total GHG emissions (in CO_2 equivalent[81] terms) from the lifecycle of natural gas used in Canada. The remaining one-fifth are "upstream" emissions from production, processing, transmission and distribution of the gas.[82] Of these upstream emissions, about half come from burning natural gas to power production facilities and pipelines; approximately one-third come from unintentional "fugitive" leaks of methane; and most of the remainder is CO_2 removed from raw natural gas and vented to the atmosphere.[83] Different natural gas deposits contain different amounts of CO_2 in the raw gas. For instance, Horn River shale gas in British Columbia contains about 12 per cent CO_2, while Utica shale gas in Quebec contains less than one per cent CO_2.[84]

As estimates like those just cited indicate that the upstream GHG emissions in the lifecycle of natural gas remain relatively modest in comparison to the emissions from using it as an end product, it is generally accepted that natural gas has considerably lower GHG emissions than other fossil fuels on a full lifecycle basis.[85]

It is not yet entirely clear to what extent the production of unconventional gas results in significantly more GHG emissions, on average, than the production of conventional gas. A recent study[86] of GHG emissions from the Barnett shale gas deposit in Texas, published by the Environmental Defense Fund (EDF), found that average upstream GHG emissions per unit of gas produced there are about 40 per cent *lower* than average upstream GHG emissions per unit of natural gas currently produced in Canada (again based on Environment Canada estimates).[87] However, raw Barnett shale gas contains only about 1.5 per cent CO_2 – much less than the initial sources of Canadian shale gas.[88] Also, the U.S. Environmental Protection Agency (EPA) recently published a revised emission factor,[89] for methane vented to the atmosphere during the hydraulic fracturing of unconventional gas wells, that is nearly twice the one[90] used in the EDF study. Using the EPA factor would have increased the total GHG emissions (CO_2 equivalent) in the EDF study by about 10 per cent. But the EPA notes that its factor is highly uncertain; it also notes that vented methane emissions can be nearly eliminated, in CO_2 equivalent terms, by flaring them, and that this is required in certain states.[91]

A study recently published in the scientific journal *Climatic Change* suggests that emissions of methane during the lifecycle of natural gas may be much higher than conventional estimates (such as those by Environment Canada). The study concludes that total GHG emissions from the lifecycle of natural gas may, as a result, be close to, or even higher than, those from the lifecycle of coal – particularly in the case of shale gas. [92,93] The lead author has, however, acknowledged that the study is necessarily based on "sparse" and "poorly documented" information.[94] Clearly, there is a need for research to quantify much more reliably the methane emissions associated with natural gas. The economic modelling studies described in Section 3 of this report are based on conventional estimates of those emissions. If those estimates are eventually established to be too low, then our conclusions (Section 4) will need to become less favourable to natural gas.

2.5 Non-climate environmental impacts

2.5.1 AIR EMISSIONS

Natural gas combustion tends to produce much smaller amounts of key air pollutants than other fossil fuels; this is illustrated by Table 5 for the case of electricity generation. Environment Canada does not quantify total national emissions from natural gas combustion, but they can be roughly approximated by assuming that all combustion of natural gas has the same emissions per unit of fuel as electricity generation with natural gas, for which Environment Canada does quantify total national emissions. On this basis, natural gas combustion appears to make significant contributions to Canadian emissions of nitrogen oxides and perhaps mercury, but only small contributions to national emissions of other key air pollutants (see Table 6).

Both nitrogen oxides (NO_x) and mercury are listed as toxic substances under the Canadian Environmental Protection Act because of their impacts on human health and the environment. NO_x emissions contribute to acid rain; they are also one of the main precursors to ground-level ozone and fine particulate matter, which are the main constituents of smog. Health Canada has acknowledged that air pollution is associated with thousands of premature deaths in Canada every year.[95] Mercury is a highly toxic metal for which the federal government has taken a series of actions to reduce releases to the environment.[96]

NO_x emissions from natural gas-fired turbines can be reduced by 80 to 95 per cent, relative to standard technology, using selective catalytic reduction (SCR).[97] SCR has a cost of only 0.1–0.3 cents per kilowatt-hour in electricity generation,[98] and has been required by the U.S. EPA on all combined cycle natural gas power plants in the past several years.[99]

Table 6. Contribution of natural gas combustion, and production/processing of oil and gas, to Canadian emissions of key air pollutants[100]

		PM_{10}	$PM_{2.5}$	SO_x	NO_x	VOC	CO	NH_3	Pb	Cd	Hg
Contribution to total emissions from industry[101] and all fuel combustion	All combustion of natural gas[102] (approximated)	5%	6%	1%	18%	1%	2%	5%	0.2%	5%	10%
	Production and processing of petroleum and natural gas	2%	3%	9%	19%	26%	5%	6%	Not quantified		

KEY: PM_{10} = particulate matter under 10 microns; $PM_{2.5}$ = particulate matter under 2.5 microns; SO_x = sulphur oxides; NO_x = nitrogen oxides; VOC = volatile organic compounds; CO = carbon monoxide; NH_3 = ammonia; Pb = lead; Cd = cadmium; Hg = mercury.

Significant air pollution is also generated by the production of natural gas. Production and processing of petroleum and natural gas combined account for a significant share of Canadian emissions of volatile organic compounds (VOC), NO_x and SO_x (see Table 6). According to a study commissioned by the Canadian Association of Petroleum Producers, oil production accounts for the bulk of these VOC emissions, but natural gas production accounts for the bulk of the NO_x and SO_x emissions.[103]

Some natural gas deposits contain significant amounts of hydrogen sulphide (H_2S) – a gas that is deadly at high enough concentrations. Most H_2S is normally removed and destroyed, or reinjected underground, during gas processing, but some is released to the atmosphere[104] and dangerous releases are possible in case of accident. Fatalities from H_2S in natural gas do still occasionally occur.[105,106]

Natural gas wells[107] and processing plants[108] can be a significant source of air emissions of benzene, a known human carcinogen.[109]

2.5.2 IMPACTS ON WATER

Unconventional natural gas production presents a hazard to freshwater resources because it involves drilling and fracturing rock under the land surface, transporting hazardous substances through the resulting cavities, and producing large volumes of contaminated wastewater. In addition, gas production using hydraulic fracturing consumes large amounts of water. The hazard is compounded because Canadian regulatory authorities generally have only a limited understanding of the structure and use of groundwater resources.[110] For example, in November 2010 the Quebec Environment Ministry acknowledged that its groundwater mapping program does not currently cover all the areas targeted for shale gas production; and in no area does the program determine how deep fresh water extends – information that is needed to ensure that the surface casings (see below) of natural gas wells go deep enough to protect fresh water.[111] In December 2010, the Auditor General of British Columbia found that the Ministry of Environment's "information about groundwater is insufficient to enable it to ensure the sustainability of the resource."[112]

Migration of natural gas

Natural gas wells are lined by layers of steel casing surrounded by cement, to prevent any contact between the contents of the well and the surrounding rock and water underground. The cement should prevent any migration of water or gas along the wellbore. However, inadequate cementing/casing can result in leaks. The recent BP *Deepwater Horizon* oil disaster in the Gulf of Mexico is a notorious example of this.[113]

The main constituent of raw natural gas is methane. Groundwater and drinking water wells can sometimes contain biologically generated methane that has nothing to do with industrial activities.[114] However, migration of natural gas to the surface, including into water wells and other surface structures, as a result of inadequate cementing/casing of oil or gas wells (in some cases old, abandoned wells), has been clearly established in multiple settings, including oil wells in Alberta and coalbed methane wells in the U.S.[115] In 2009 the Pennsylvania Department of Environmental Protection established that faulty cementing/casing of modern shale gas wells was the cause of gas migration into the water supplies of 14 homes.[116] Additional evidence for methane contamination of Pennsylvania drinking water associated with shale gas extraction was presented in a recent study published in the *Proceedings of the National Academy of Sciences.*[117] The study presents strong evidence that the methane is from the shale gas, not shallow biological sources, and identifies leaky well casings as the most likely culprit.

Similarly, in November 2010 Quebec government inspectors detected very high methane concentrations – in excess of 20 per cent – in the air surrounding four different shale gas exploration wells.[118] The provincial environment ministry has confirmed in at least one of these cases that the methane is from the shale gas, not biological sources.[119]

Methane is explosive but not toxic. However, as noted in Section 2.5.1, raw natural gas can contain toxic substances such as hydrogen sulphide and benzene. If natural gas is migrating into groundwater, then benzene may be doing so too.

Migration of fracture fluids

In cases of faulty cementing/casing of natural gas wells using hydraulic fracturing, there is a potential for fracture fluids to contaminate fresh groundwater. However, it is not clear that there have been any cases where such contamination can be unequivocally attributed to underground propagation of fracture fluids.[120] It must also be recognized that while the *combination* of hydraulic fracturing with horizontal drilling is new, fracturing is not: more than one million wells have been hydraulically fractured in North America over six decades.[121]

The composition of fracture fluids can vary widely. In shale gas production, typical fluids consist of water, sand and chemicals added to modify the viscosity of the fluid, kill bacteria, prevent certain chemical reactions, etc. The New York State Department of Environmental Conservation (NYSDEC) has compiled a list of nearly 200 chemicals used or proposed for use in hydraulic fracturing of the state's shale gas deposits. While some of the chemicals are not hazardous, NYSDEC notes significant potential negative health effects from others.[122] Democratic members of three U.S House of Representatives committees recently published a list of 750 substances used in hydraulic fracturing of oil and gas wells in the U.S. between 2005 and 2009, based on information voluntarily provided by producers. Of these substances, 29 are known or possible human carcinogens and/or regulated toxic chemicals.[123]

Until recently, companies were generally reluctant to disclose the composition of their fracture fluids, but this is now changing. For example, U.S. state regulators have launched a website where over 40 companies are now voluntarily disclosing fracture fluid composition on a well-by-well basis.[124] Several U.S. states now require disclosure to regulators,[125,126] and Quebec has announced that it will do so,[127] although it is not clear how much of the information will be accessible by the public. In Canada, companies are generally required to report substances injected underground to the National Pollutant Release Inventory (NPRI), but fracture fluids escape this provision as oil and gas wells are currently exempted from the NPRI.[128]

Between 20 per cent and 85 per cent of fracture fluids remain permanently underground.[129] The potential for these fluids to contaminate fresh water directly, via the fractured rock, depends on the depth of the gas deposit. Most Canadian[130] and U.S.[131] shale gas deposits range from several hundred to several thousand metres below the surface – much deeper than the typical deepest extent of fresh water (groundwater becomes salty deeper than a few hundred metres[132]). The Ground Water Protection Council, the association of U.S. state groundwater regulatory agencies (including departments of both environment and natural resources), has concluded that the depth and the intervening rock barriers make any contamination of groundwater extremely unlikely.[133] However, at least one hydrogeologist has produced a detailed analysis concluding that deep fracture fluids could reach fresh water in decades to centuries.[134]

Some unconventional gas deposits – such as certain coalbed methane deposits in Alberta[135] – do lie at the same shallow depths as fresh water. Alberta's Energy Resources Conservation Board (ERCB) prohibits fracturing within 200 metres (horizontal) if the depth of a water well is within 50 metres (vertical) of the proposed well fracturing depth; and the ERCB allows only "non-toxic" fracture fluids at depths where fresh water occurs.[136] However, the British Columbia Oil and Gas Commission states: "Fracture propagation via large scale hydraulic fracturing operations has proven difficult to predict. Existing planes of weakness in target formations may result in fracture lengths that exceed initial design expectations."[137] The commission is aware of numerous "fracture communication incidents" in the province in which hydraulic fracturing caused an unintended connection with adjacent wells.[138] This suggests that some fracture fluids from shallow unconventional gas production are likely to enter fresh groundwater.

Industry representatives state that genuinely non-toxic fracture fluids are available for some applications, although they cost more than typical fluids.[139] While this is encouraging, the uncontrolled addition of any extraneous substances to freshwater resources is a cause for concern.

Surface contamination

The most significant risk of contamination of fresh water by natural gas production appears to result from spills or inadequate disposal of "produced water" – water that comes out of the well along with the gas. Produced water is typically stored in open pits or tanks before being disposed of.[140,141] In general, produced water is a combination of (typically very salty) water naturally occurring in the gas deposit, and the "flowback" portion of the fracture fluids. According to a major recent study by the Massachusetts Institute of Technology (MIT), "The environmental impacts of shale [gas] development are manageable but challenging. The largest challenges lie in the area of water management, particularly the effective disposal of fracture fluids."[142] Part of the challenge is the very large volume of fluids (see below), which necessarily increases the risk of spills.

The industry's recent track record in this area has been poor in Pennsylvania, which is currently at the forefront of shale gas development. According to the state's Department of Environmental Protection (June 2010), "Since January 2010, the department has completed nearly 1,700 inspections of Marcellus Shale drilling sites across the state, finding more than 530 violations that range from poor erosion and sediment controls to administrative violations to spills and leaks from improperly managed or constructed [wastewater] containment pits. [...] During its inspections, the department has identified problems with improperly constructed or maintained drilling waste and flowback containment pits at 29 of the 364 Marcellus Shale wells drilled this year. [...] The department has also responded to spills from a range of sources including leaking fuel storage tanks, unsecured valves on fracwater storage tanks and accidents involving trucks hauling wastewater."[143]

Some shale gas producers in Pennsylvania have been sending wastewater to municipal sewage treatment plants, but most of these cannot deal with the high levels of dissolved salt (and, in some cases, natural radioactivity[144]), which is therefore discharged into waterways.[145] In Alberta[146] and British Columbia,[147] produced water is usually disposed of, untreated, in deep wells below the freshwater zone.

The U.S. EPA has now launched a scientific study "to investigate the possible relationships between hydraulic fracturing and drinking water," but initial results are not expected before late 2012.[148] It should be noted that drilling muds – fluids used to drill wells prior to fracturing – are an additional potential source of groundwater contamination through migration underground or surface contamination.[149]

Water consumption

The amounts of water consumed by natural gas production using hydraulic fracturing could result in significant environmental impacts in drier regions.

Eight to 15 million litres of water are typically needed to drill and complete a shale gas well.[150] However, 60 million litres per well have recently been used in British Columbia's Horn River basin.[151] In the Barnett deposit in Texas, where shale gas production is currently most advanced, almost 3,000 new wells were added in 2008.[152] A hypothetical shale gas region drilling 3,000 wells per year, and using 15 million litres of water per well, would be consuming about 120 million litres per day – the same as a city of about 300,000 people.[153] If the same hypothetical region were using 60 million litres per well, it would be consuming water at the same rate as a city of about 1.2 million people.

Although these are large numbers, production of one unit of energy from shale gas consumes a comparable amount of water to coal, less than oil sands and far less than biofuels.[154] Nonetheless, the recent rapid development of the Marcellus shale deposit in Pennsylvania, where over 1,000 wells were drilled in 2010,[155] "has placed tremendous strain on the state's water resources."[156] In August 2010 the summer drought forced the British Columbia Oil and Gas Commission to order a suspension of industry withdrawals of surface water in the shale gas region in the northeast of the province.[157]

Increased recycling of fracture fluids may offer a solution. Recycling of all fracture fluids – reducing the industry's fresh water consumption by 30 to 50 per cent – may be technically and economically feasible.[158] Devon Energy, a major producer in the Barnett shale, is already recycling some fluids on a commercial scale.[159] It is not clear how much energy use and associated emissions result from removal of salt from the used fluids.

2.5.3 IMPACTS ON THE LANDSCAPE AND QUALITY OF LIFE

All natural gas production will have significant impacts on the landscape (or marine environment, in the case of offshore production). Here we will consider shale gas and Arctic gas, since they are projected to account for the bulk of new Canadian production in the coming years (see Figure 4).

Shale gas production requires one well pad (comprising multiple wells) roughly every square mile[160] (a mile is 1.6 km), and each well pad typically occupies an area about 100 metres by 100 metres (one hectare).[161] Each well pad also requires an access road and pipeline infrastructure. Drilling and fracturing a multi-well pad requires up to 18 months[162] of noisy day-and-night operations, and many thousands of truck trips.[163] Once completed, wells will produce for several years, although the production level of each well falls off rapidly, typically by half from the first to the third year.[164] To sustain a constant level of production, producers must therefore continually drill new wells. For example, based on the experience of the Barnett shale, 800 new wells (on the order of 100 new well pads[165]) would need to be drilled every year to sustain production of three billion cubic feet per day[166] (about one-fifth of Canada's current production[167]) over 20 years.

In the Arctic, the Mackenzie Gas Project includes three "anchor fields" that are expected to produce about 5.6 trillion cubic feet of gas over about 25 years[168] – equivalent to an average rate of about 0.6 billion cubic feet per day. This is expected to require six well pads for the entire period, and a total of 523 hectares of physical disturbance,[169] not including the area disturbed by processing and pipeline facilities. It is notable that the number of well pads required to produce from this conventional gas-like resource is on the order of 100 times smaller than the number needed to produce the same amount of shale gas over the same time period.[170] The number of well pads in the Mackenzie Gas Project may, however, be unusually small for conventional-like gas development.

In addition, natural gas production will inevitably be subject to accidents that will further impact the environment, public safety and quality of life. For example, gas well blowouts have occurred recently in the Marcellus shale region in Pennsylvania and West Virginia.[171]

2.6 Environmental assessment

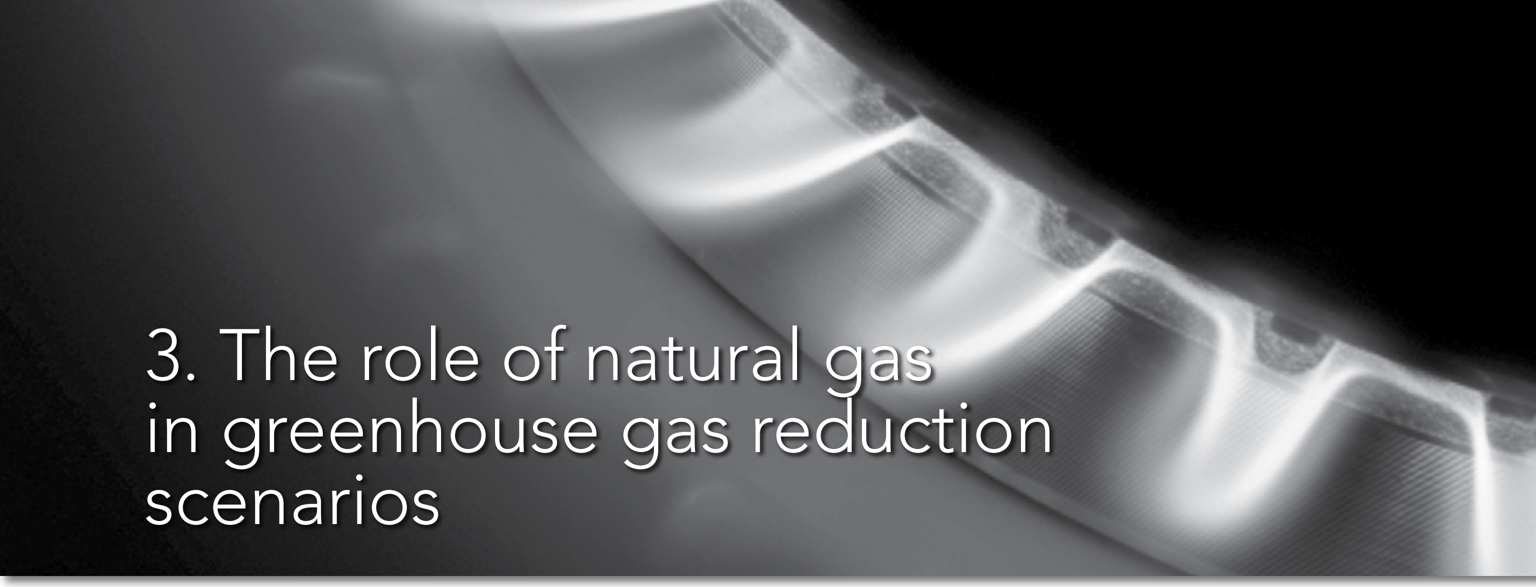
Given the variety, complexity and scale of the impacts of natural gas production, it clearly needs to be subject to thorough environmental assessment. However, typical environmental assessments look at small production increments in isolation, and do not address the total, or cumulative, impacts of development. Therefore, in addition to typical assessments focused on minimizing the impacts of individual projects, there needs to be assessment and management of *cumulative* impacts of increasing development in a given region, which generally proceeds through hundreds or thousands of individual projects operated by multiple firms.

Currently, however, most oil and gas wells in Canada are explicitly exempted from even the normal facility-by-facility environmental assessment process; this is the case, notably, in Alberta,[172] British Columbia[173] and Quebec.[174] Although provincial environment ministries play a role in issuing certain authorizations, oil and gas wells are generally subject to permitting procedures administered by regulatory bodies that may not always have a culture that prioritizes environmental protection. In some cases, regulatory bodies can be seen as being in a conflict of interest if they have a role promoting oil and gas development while also being responsible for environmental safeguards that may make development more difficult. For example, in British Columbia the Deputy Minister of Natural Resources chairs the Oil and Gas Commission, the body that grants oil and gas permits.[175]

In 2010 Quebec's environment minister mandated high-profile public hearings into proposed shale gas development in the province.[176] In accordance with the report from the hearings, the minister has now launched a "strategic" environmental assessment of the development of the province's shale gas resources. The assessment is expected to take about two years, during which time the minister will only authorize hydraulic fracturing operations if they are recommended for research purposes by the expert committee undertaking the assessment.[177] However, at present there is no assurance that the exemption of gas wells from normal environmental assessment will be removed.

Natural gas wells in the Arctic and offshore are subject to federal environmental assessments, by bodies such as the Mackenzie Valley Environmental Impact Review Board,[178] the Canada-Nova Scotia Offshore Petroleum Board[179] and the Canada-Newfoundland Offshore Petroleum Board.[180]

Private landowners have little ability to prevent natural gas development when governments have approved it. On more than 90 per cent of land in Canada, mineral rights – including rights to oil and gas – are owned by the Crown, not the owner of the surface property. Governments allocate those rights to companies via leases that allow exploration for and production of the below-ground resources.[181] Landowners can generally negotiate the terms of access to their land by producers, including some financial compensation, but have little or no power to prevent it.[182,183] This makes it especially important that governments take decisions about development that are in the interest of citizens.



3. The role of natural gas in greenhouse gas reduction scenarios

3.1 Introduction

As noted earlier, replacement of other fossil fuels by natural gas is expected to reduce GHG emissions, but not nearly by enough to allow it to be a long-term solution to climate change, unless it is used in conjunction with CO_2 capture and storage (CCS). Supporters of natural gas therefore often portray it as a "bridging" fuel that can help reduce emissions in the early stages of a long-term shift to emissions-free energy.

Economic modelling studies provide a sophisticated means of determining whether a "bridging" role for natural gas makes sense. Models of national economies can project the likely future roles of different forms of energy under a range of assumptions about supply, demand, international trade and government policies. Models seek to integrate the key factors that determine choices among competing energy options: energy efficiency, fossil fuels with and without CCS, nuclear and renewable energy.

3.2 Recent economic modelling studies

Below we review conclusions about the future of natural gas from five prominent modelling studies covering GHG reduction scenarios globally, in North America and in Canada. We have not attempted to review all published studies, but those selected are a strong sample of leading economic models and authoritative authors. They are all recent enough to reflect the unconventional gas revolution.

Because of its economic efficiency and ability to cover most emissions, it is widely agreed that the central policy to reduce GHGs should be an economy-wide price on emissions (a "carbon price"), established by a cap-and-trade system or a carbon tax. All the studies reviewed below make this assumption.[184] The majority of them also incorporate complementary policies, such as regulations and public investments to overcome various market failures.

The results of modelling studies can be quite sensitive to assumptions about issues such as the relative costs of competing technologies, the manner in which economic actors take decisions, or international trade. It is therefore striking that all the studies reviewed agree (except in one case, discussed below) that natural gas consumption will be lower than the business-as-usual level when a carbon price is implemented – whether that price is modest or robust. In most cases gas consumption is projected to rise in absolute terms, in the medium term, but always less than under business-as-usual. In the two cases where policies are designed to be consistent with limiting average global warming to 2°C[185] – the objective that governments (including the Government of Canada) have unanimously endorsed in the UN climate negotiations[186] – North American or Canadian natural gas consumption is not projected to rise more than a small amount above current levels. (These cases are the IEA 450 scenario and the Jaccard and Associates 2°C target.)

The only case where natural gas consumption is projected to be higher than business-as-usual, in the presence of a carbon price, is the scenario in the MIT study where there is full global trade of natural gas. As already noted in Section 1.3, LNG exports from North America to other continents would face many hurdles, including competition from other suppliers and uncertainty about the future prices in destination countries needed to support the high capital costs of LNG infrastructure. Indeed, in the MIT study's full global trade scenario, it is the other way around: the U.S. is projected to import large volumes of cheap gas from the Middle East and Russia, because production costs are even lower there despite the unconventional gas revolution in North America. This trade would reduce prices, boosting U.S. consumption. But this scenario would entail the challenge of U.S. political sensitivity to dependence on foreign energy – casting considerable further doubt on its plausibility.

The IEA projects inter-continental LNG trade rising to 11 per cent of global natural gas consumption by 2035 in its "new policies" scenario (modest carbon price), but most of this LNG is projected to go to Asia, and none of it comes from North America.[187] Instead, North America imports LNG, but only enough to satisfy seven per cent of its consumption in 2035.[188] Similarly, the U.S. Department of Energy continues to foresee no new U.S. LNG export capacity between now and 2035.[189] These analyses suggest that construction of a proposed LNG export terminal in Kitimat, British Columbia, may be less likely than has been reported.[190]

3.2.1 INTERNATIONAL ENERGY AGENCY (2010)

The IEA, an intergovernmental organization of 28 developed countries, produces an annual World Energy Outlook that is influential in international negotiations on climate and energy policy. The outlook is constructed using the IEA's World Energy Model. The 2010 edition of the outlook presents three scenarios[191] for the global energy system between 2008 and 2035:

- A "current policies" (business-as-usual) scenario in which no new government policies affecting GHG emissions are implemented if they were not enacted by mid-2010.
- A "new policies" scenario in which there is "cautious implementation" of current national commitments on GHG emissions for 2020, with the same pace of decline in GHG intensity continued afterwards. A carbon price is implemented in North America only after 2020; it reaches US$40 per tonne of CO_2 by 2030 and US$50 by

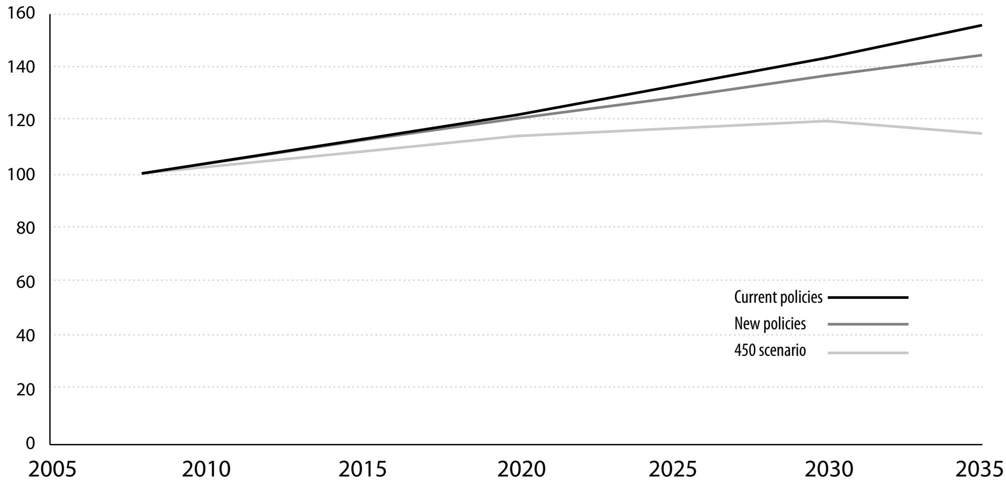


Figure 5. Global natural gas consumption in the IEA's World Energy Outlook 2010[192] (2008=100)

NOTE: the World Energy Outlook does not provide data for years between 2008 and 2015, so the temporary drop in consumption resulting from the recent recession is not shown.

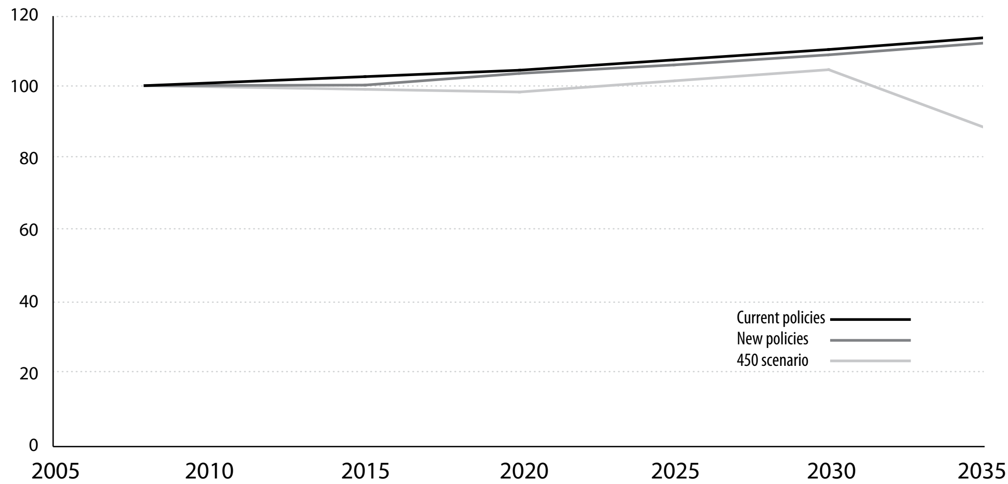


Figure 6. North American (U.S., Canada, Mexico) natural gas consumption in the IEA's World Energy Outlook 2010[193] (2008=100)

NOTE: the World Energy Outlook does not provide data for years between 2008 and 2015, so the temporary drop in consumption resulting from the recent recession is not shown.

2035 (in 2009 dollars). There are numerous complementary policies, which vary by jurisdiction.

- A "450 scenario" with more ambitious policies to put the world on track to stabilize atmospheric GHG concentrations at 450 parts per million of CO_2 equivalent,[194] consistent with a chance of limiting average global warming to 2°C. The carbon price in developed countries[195] reaches US$45 per tonne of CO_2 in 2020, US$105 in 2030 and US$120 in 2035. Again there are numerous complementary policies.

Figures 5 and 6 show the evolution of natural gas consumption globally and in North

America under these three scenarios. Consumption increases steadily under both the current and new policies scenarios, but under the 450 scenario it starts falling in absolute terms by 2030, and is well below the current policies level by 2035. In North America, the 450 scenario sees a switch from coal to gas in electricity generation between 2020 and 2025, but this is followed by an even sharper switch to nuclear and renewables as the carbon price rises further.[196] It is noteworthy that even the more modest GHG policies of the new policies scenario slow the rate of growth of gas consumption relative to business-as-usual – presumably because energy efficiency, which often has a low cost in terms of dollars per tonne of CO_2, is reducing demand for natural gas more sharply than fuel switching is increasing it.

3.2.2 MASSACHUSETTS INSTITUTE OF TECHNOLOGY (2010)

MIT's Energy Initiative, a major interdisciplinary effort supported by several prominent energy companies,[197] recently published an interim report on its investigation into the future of natural gas, with a focus on the U.S.[198] The report includes the results of an economic modelling exercise using the MIT Emissions Prediction and Policy Analyses (EPPA) model and the U.S. Regional Energy Policy (USREP) model. The EPPA model is a global model with the U.S. as one of its regions.

The report presents results[199] for the following three policy scenarios:

- No new policies to reduce GHG emissions (business-as-usual).
- A carbon price sufficient to reduce total U.S. GHG emissions to 50 per cent below the 2005 level by 2050, without international offsets. The price reaches approximately US$100 per tonne of CO_2 equivalent in 2030 and approaches US$240 by 2050. Other developed countries implement similar policies. Emission reductions by developed countries would have to be considerably greater (at least 80 per cent by 2050) for the world to have a chance of limiting average global warming to 2°C.[200]
- The same carbon pricing policy as above, accompanied by the development of a truly global market for natural gas, via the expansion of LNG and pipeline infrastructure to link continents.

Figure 7 shows the evolution of U.S. natural gas consumption under the three scenarios, using a mean estimate of the size of U.S. natural gas resources. The no new policies and carbon pricing scenarios look similar to their analogues in the World Energy Outlook: with no new policies, gas consumption increases steadily, but with carbon pricing consumption (and production) grows more slowly and eventually starts falling in absolute terms. In the MIT study, however, even with robust carbon pricing gas consumption remains slightly above the 2010 level in 2050. Although not shown in Figure 7, the picture is qualitatively the same with a high estimate of U.S. gas resources: with carbon pricing, consumption falls in absolute terms after 2040. With a low resource estimate, this is true even without carbon pricing.

In the third scenario, with full global trade of natural gas, U.S. consumption is boosted by lower prices and heavy imports of cheap gas from the Middle East and Russia. The plausibility of this scenario was discussed above.

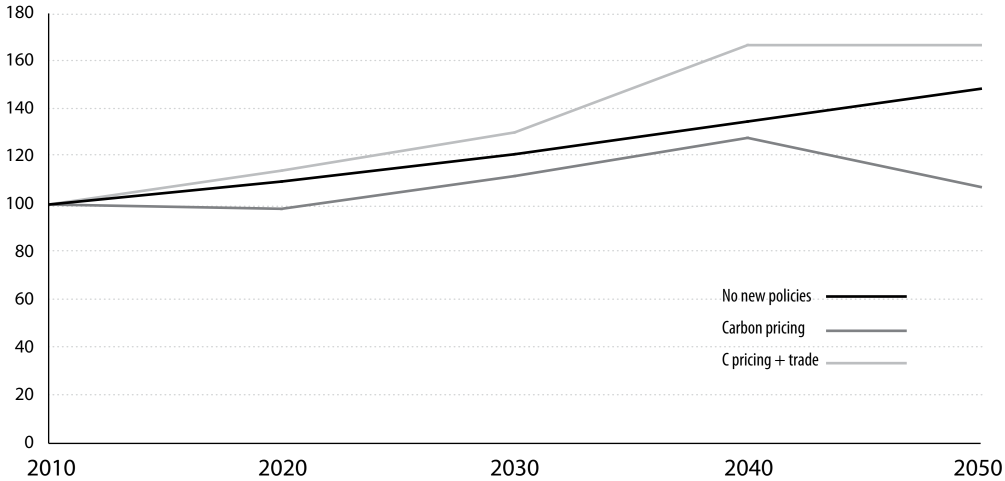


Figure 7. U.S. natural gas consumption in the MIT study (2010=100)

The MIT study also includes a longer-term version of the carbon pricing scenario in which total U.S. GHG emissions are reduced to 80 per cent below the 2005 level by 2100. Between 2045 and 2065, natural gas use in electricity generation falls sharply to zero, and only small amounts of gas-fired electricity with CCS appear after 2070.

3.2.3 RESOURCES FOR THE FUTURE (2010)

Resources for the Future (RFF), a leading U.S. environmental economics research institute, recently published an economic modelling study[201] examining the role of natural gas in meeting U.S. GHG objectives in the context of a large low-cost shale gas resource. The study used RFF's variant of the U.S. Department of Energy's National Energy Modeling System (NEMS).

The study examined the following four scenarios:[202]

- A business-as-usual (BAU) scenario based on the 2009 edition of the Department of Energy's Annual Energy Outlook – no changes to the slate of government programs currently in place. The estimates of shale gas resources in this scenario are relatively limited.
- A modified BAU scenario with more abundant shale gas resources and lower production costs, reflecting more recent estimates.
- A policy scenario based on the first BAU scenario with an economy-wide cap-and-trade system similar to that in the American Clean Energy and Security Act passed by the House of Representatives in June 2009 (but not the Senate). The carbon price rises from US$19 per tonne of CO_2 in 2030 to US$67 in 2030 (in 2007 dollars). By comparison with the IEA and MIT studies, this falls well short of being consistent with limiting average global warming to 2°C.
- A policy scenario based on the second BAU scenario, with more abundant shale gas and the same cap-and-trade system.

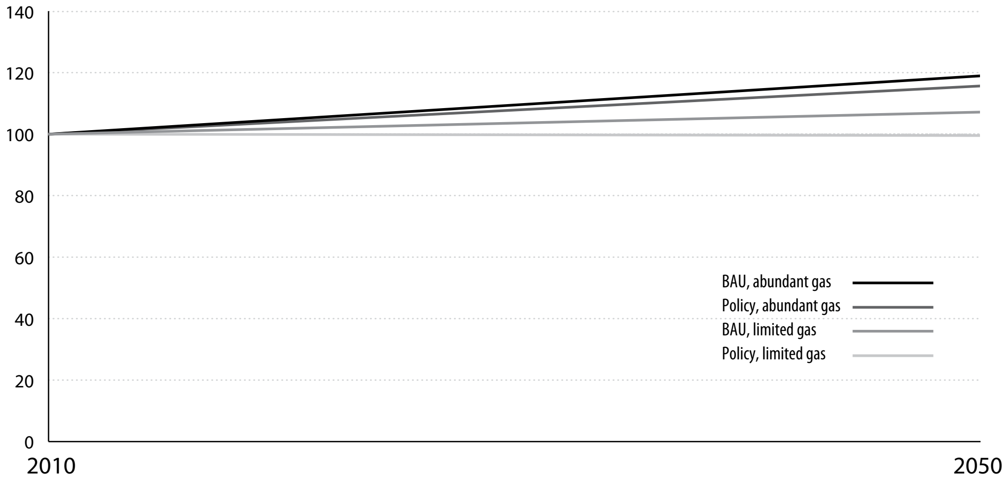


Figure 8. U.S. natural gas consumption in the Resources for the Future study (2010=100)

NOTE: the RFF report does not provide data for intermediate years, although the model used does generate it.

Figure 8 shows the evolution of U.S. natural gas consumption under the four scenarios. Consumption increases with more abundant shale gas resources, as one would expect. But again, as in the World Energy Outlook, even a modest carbon price reduces natural gas consumption below business-as-usual levels. The authors argue that natural gas "creates a bridge to a low-carbon future" because the carbon price is very slightly lower when shale gas is more abundant. But this effect seems very small: the carbon price reduction is just 12 cents in 2012 and 43 cents in 2030.

3.2.4 JACCARD AND ASSOCIATES (2009)

In 2009, the Pembina Institute and the David Suzuki Foundation commissioned M.K. Jaccard and Associates to conduct an economic modelling study[203] to understand how Canada could meet two GHG emissions targets for 2020: the federal government's then target of a 20 per cent reduction below the 2006 level; and a more ambitious 25 per cent reduction below the 1990 level, intended to be a fair Canadian contribution to limiting average global warming to 2°C. The study used Jaccard and Associates' CIMS model, which has been widely used by the governments of Canada, Alberta and other provinces. CIMS contains a detailed database of technologies relevant to GHG emissions.

The study modelled a carbon price plus a range of complementary policies to meet each of the two targets. For the government's target, the carbon price started at $40 per tonne of CO_2 equivalent in 2011 and rose to $100 by 2020 (in 2005 Canadian dollars). For the 2°C target, the carbon price started at $50 per tonne in 2010 and rose to $200 by 2020.

Figure 9 shows the level of Canadian natural gas consumption under the study's business-as-usual (BAU) scenario, and when meeting each of the two targets. As in the studies reviewed above, the GHG reduction policies reduce natural gas consumption below business-as-usual levels: to meet either the government's target or a more ambitious one, Canada's gas consumption would need to stay almost flat between 2010 and 2020.

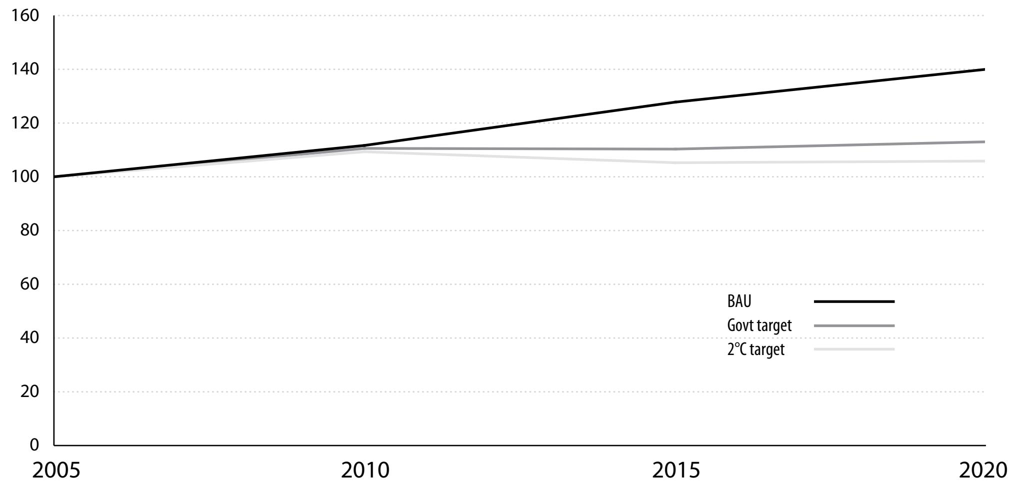


Figure 9. Canadian natural gas consumption in the Jaccard and Associates study[204] (2005=100)

3.2.5 WESTERN CLIMATE INITIATIVE (2010)

The Western Climate Initiative (WCI) is a partnership between the governments of seven U.S. states (AZ, CA, MT, NM, OR, UT, WA) and four Canadian provinces (BC, MB, ON, QC) that have proposed to jointly meet their GHG reduction targets for 2020 using an economy-wide cap-and-trade system and complementary policies. In 2010 the WCI published an updated economic analysis[205] of the proposed policies. The analysis employed the widely used ENERGY 2020 model.

Figure 10 shows the projected evolution of natural gas consumption in the WCI region under a business-as-usual scenario with no new policies beyond those already adopted, and under a scenario in which the proposed WCI cap-and-trade system and a range

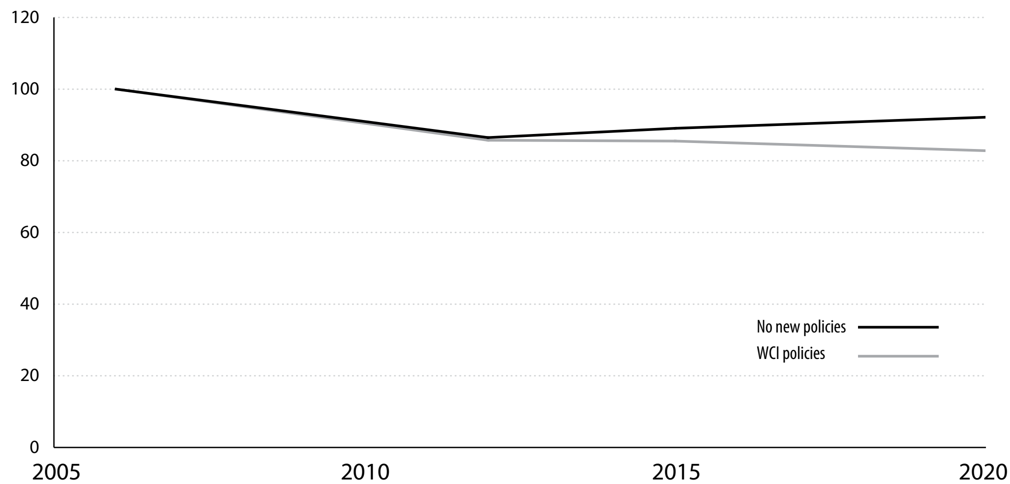


Figure 10. Natural gas consumption in the WCI region, according to the WCI's updated economic analysis (2006=100)

of complementary policies are implemented. In the policy scenario the carbon price reaches US$33 per tonne of CO_2 equivalent by 2020 (2007 dollars). Once again, this modest carbon price reduces natural gas consumption significantly below business-as-usual levels, turning a gentle consumption increase into a gentle decrease.

3.3 New economic modelling conducted for this report

For this report we commissioned EnviroEconomics[206] to conduct an original economic modelling study to examine the medium-term future of natural gas in North America under GHG reduction scenarios. We selected the GEEM-NA model, a static computable general equilibrium (CGE) model of the Canadian and the U.S. economies maintained by M.K. Jaccard and Associates. GEEM-NA was used in the recent study of Canada-U.S. climate policy choices by the National Round Table on the Environment and the Economy (NRTEE),[207] and is currently being used by provincial governments.

The version of GEEM-NA used for this report includes eight regions (British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, the Atlantic provinces and territories, and the U.S.) and 22 economic sectors, including three natural gas production sectors – conventional (including frontier), tight and shale gas. The regions trade with one another, reflecting *inter alia* the tight linkage between the Canadian and U.S. natural gas markets. Commodities, including LNG, can also be traded with the rest of the world. The starting point for the modelling is a business-as-usual (BAU) forecast of economic activity to 2030. Our BAU scenario falls roughly in the middle of a wide range of published forecasts.

The model tracks GHG emissions corresponding to 88 per cent of Canada's national GHG inventory[208] in 2005 (not included are emissions from agriculture and waste, hydrofluorocarbons [HFCs] and sulphur hexafluoride [SF_6]). The emission profiles of the natural gas sectors vary according to production techniques and the amount of CO_2 in the raw gas. In the GHG reduction scenarios, a carbon price applies to all the emissions tracked in the model. We tested North America-wide carbon prices of \$20, \$40, \$60, \$80, \$100 and \$120 per tonne of CO_2 equivalent (in 2009 Canadian dollars). In each case, economic actors have full certainty that the carbon price will reach the specified level by 2030.

Because of concerns about the impacts of the large volume of new shale gas production projected in coming years, we focused on the role of shale gas by testing GHG reduction scenarios in which (i) governments do not permit any shale gas production[209] and, alternatively, (ii) the supply of low-cost shale gas is considerably larger, in both Canada and the U.S., than in the BAU scenario. In addition, because of the potentially important role of CCS in facilitating more natural gas production and use, we tested scenarios in which all applications of CCS are (i) twice as costly, and (ii) half as costly, as in the BAU scenario.[210]

Figure 11 shows the projected evolution of natural gas consumption in North America under the BAU scenario and our range of carbon prices. Just as in all the studies reviewed in Section 3.2, any level of carbon price reduces natural gas consumption below the business-as-usual level. When the carbon price exceeds about \$65 per tonne of CO_2 equivalent, gas

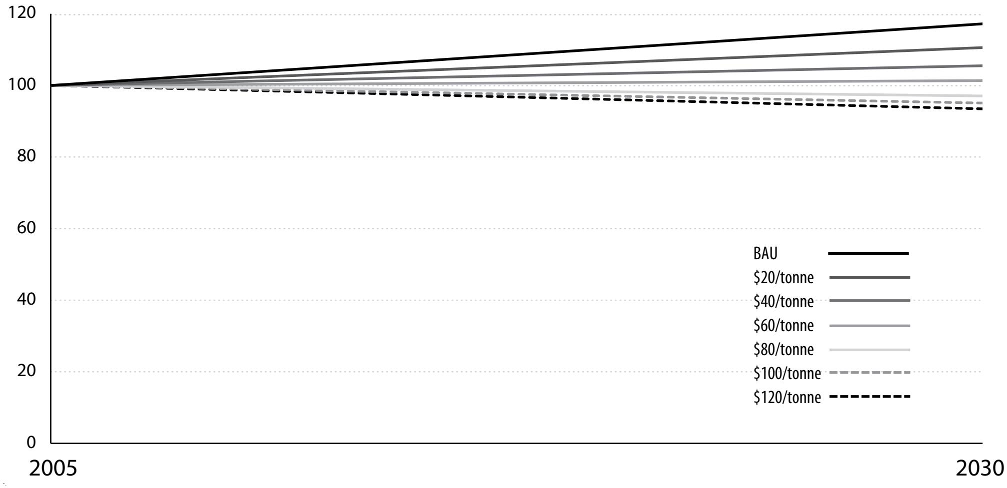


Figure 11. North American (U.S., Canada) natural gas consumption in the study commissioned for this report (2005=100)

consumption in 2030 falls below the 2005 level. The results depicted in Figure 11 change little when there is no shale gas or more abundant shale gas; the carbon price at which gas consumption in 2030 falls below the 2005 level is about $60 with no shale gas and about $70 with more abundant shale gas. Doubling the cost of CCS makes nearly no difference up to and including $60 per tonne, but slightly reduces natural gas consumption at $120. Halving the cost of CCS makes a bigger difference: now gas consumption in 2030 falls below the 2005 level only at $100 per tonne.

It is worth recalling that according to the IEA's "450 scenario," having a chance of limiting average global warming to 2°C requires the carbon price in developed countries to reach US$105 per tonne of CO_2 by 2030 (see Section 3.2.1).

Table 7 shows the projected evolution of natural gas production. Total North American production is closely aligned to total consumption (as just described), consistent with a very small volume of intercontinental LNG trade. Under business-as-usual, production falls somewhat in Canada and rises somewhat in the U.S, in broad alignment with the forecasts described in Section 2.2. A carbon price then reduces production in 2030 significantly relative to the business-as-usual level. When there is extra shale gas, it appears to be more competitive in Canada than in the U.S., so production is boosted in Canada and actually suffers in the U.S. When there is no shale gas, it is the other way around, with production depressed in Canada but benefiting slightly in the U.S.

Table 8 shows the projected effect of the different carbon price levels and other assumptions on national GHG emissions and GDP. With a carbon price of $120 per tonne of CO_2 equivalent, emissions in 2030 fall to 32 per cent below the 2005 level in Canada, and 35 per cent below the 2005 level in the U.S. With no shale gas, the carbon price is slightly less effective in reducing emissions (i.e., a slightly higher carbon price is needed to reach the same emissions level). But with extra shale gas, emissions are even higher for a given carbon price.

Table 7. Natural gas production in 2030, relative to the 2005 level, in the study commissioned for this report

SCENARIO	CANADA (%)	U.S. (%)	CANADA+U.S. (%)
BAU	−11	+24	+14
$60/tonne	−21	+7	−1
$120/tonne	−26	−2	−8
$60/tonne, no shale gas	−27	+8	−1
$120/tonne, no shale gas	−33	−1	−10
$60/tonne, extra shale gas	−7	+2	0
$120/tonne, extra shale gas	−16	−6	−9
$60/tonne, CCS more costly	−21	+6	−1
$120/tonne, CCS more costly	−30	−5	−11
$60/tonne, CCS less costly	−19	+9	+2
$120/tonne, CCS less costly	−23	+3	−4

Table 8. National GHG emissions and GDP in the study commissioned for this report

SCENARIO	CANADIAN GHG EMISSIONS IN 2030, RELATIVE TO 2005 (%)	U.S. GHG EMISSIONS IN 2030, RELATIVE TO 2005 (%)	CANADIAN GDP IN 2030, RELATIVE TO 2005 (%)	U.S. GDP IN 2030 RELATIVE TO 2005 (%)
BAU	+31	+23	+72.9	+77.8
$60/tonne	−1	−9	+72.1	+76.8
$120/tonne	−32	−35	+70.5	+74.5
$60/tonne, no shale gas	−3	−9	+71.9	+76.7
$120/tonne, no shale gas	−30	−34	+70.3	+74.5
$60/tonne, extra shale gas	+2	−8	+72.8	+76.7
$120/tonne, extra shale gas	−27	−34	+71.1	+74.4
$60/tonne, CCS more costly	+1	−7	+72.2	+76.8
$120/tonne, CCS more costly	−12	−31	+70.7	+74.4
$60/tonne, CCS less costly	−18	−11	+71.9	+76.9
$120/tonne, CCS less costly	−33	−37	+71.0	+74.5

At $120 per tonne, doubling the cost of CCS increases Canadian emissions considerably, but U.S. emissions only a little. Halving the cost of CCS reduces emissions – particularly in Canada at $60 per tonne. These results are related to the greater Canadian reliance on CCS in electricity generation (see below).

The projected effects on national GDP are very small. In the worst case for Canada ($120/tonne, no shale gas), the economy grows by 70.3 per cent between 2005 and 2030 (2.15 per cent per year on average) instead of 72.9 per cent (2.22 per cent per year) in the absence of a carbon price.

Table 9. Electricity production in the study commissioned for this report

	CANADA					US				
SCENARIO	ELEC. PROD. IN 2030, RELATIVE TO BAU (%)	FOSSIL WITH NO CCS (%)	FOSSIL WITH CCS (%)	HYDRO, NUCLEAR (%)	OTHER RENEWABLES (%)	ELEC. PROD. IN 2030, RELATIVE TO BAU (%)	FOSSIL WITH NO CCS (%)	FOSSIL WITH CCS (%)	HYDRO, NUCLEAR (%)	OTHER RENEWABLES (%)
BAU	0	24	0	64	12	0	69	0	21	10
$60/tonne	+24	14	0	66	20	+1	55	0	30	15
$120/tonne	+39	2	14	63	21	0	46	0	36	18
$60/tonne, no sh. gas	+25	14	0	66	20	+1	54	0	31	15
$120/tonne, no sh. gas	+35	9	0	68	23	+1	46	0	36	18
$60/tonne, extra sh. gas	+25	16	0	65	20	0	55	0	30	15
$120/tonne, extra sh. gas	+36	5	7	66	22	0	47	0	36	18
$60/tonne, CCS cost ×2	+24	14	0	66	20	+1	55	0	30	15
$120/tonne, CCS cost ×2	+34	8	0	68	23	+1	46	0	36	18
$60/tonne, CCS cost ÷2	+27	11	6	63	19	+1	51	3	30	15
$120/tonne, CCS cost ÷2	+40	3	18	60	19	−1	6	41	35	17

Note: While the GEEM-NA model does explicitly capture fuel switching between gas-fired and coal-fired electricity, it treats them as a single economic sector. The results displayed in this table should therefore be treated with caution.

Table 9 shows the projected evolution and composition of electricity production under the different carbon prices and scenarios for shale gas supply and CCS costs. A significant carbon price considerably increases Canadian electricity production relative to the business-as-usual level, but it hardly changes U.S. electricity production. This is a result of Canada starting out with a relatively low-carbon electricity sector, and the U.S. with a relatively high-carbon electricity sector.

In Canada, an increasing carbon price boosts non-hydro renewables and CCS at the expense of conventional fossil-fuelled power. In the U.S., however, an increasing carbon price boosts all the non-fossil options but not CCS (unless the cost of CCS is halved). This can perhaps be interpreted in terms of the large opportunity in the U.S. for fuel switching from coal to natural gas. In general, the results suggest that the electricity sector is quite sensitive to cost assumptions, with different options competing closely.

3.4 Additional considerations

3.4.1 NATURAL GAS IN TRANSPORTATION

Very little natural gas is currently used in transportation, but some have suggested it could become an important vehicle fuel, with lower GHG emissions than gasoline or diesel fuel, and the promise of increasing U.S. energy security by replacing foreign oil with domestic gas. According to Natural Resources Canada, natural gas has 21 to 30 per cent lower GHG emissions than diesel, on a lifecycle basis, when used in medium- and heavy-duty vehicles.[211] However, more studies are needed to confirm this statistic.[212]

Some compressed natural gas (CNG) and LNG vehicles are already commercially available in North America. Certain niche applications, such as heavy-duty vehicles that can refuel at their home base, appear to be economically attractive, with the less expensive fuel more than compensating for the more expensive vehicles.[213] However, this depends on natural gas maintaining its price advantage over diesel; the risk of this not being the case is a significant barrier to adoption.[214] The consensus appears to be that a major role for natural gas vehicles faces many obstacles – notably, the lack of public refuelling infrastructure.

A more likely, and more energy efficient, way for natural gas to fuel transportation is via electricity generated from gas.[215] None of the economic modelling studies described above appear to foresee a major role for natural gas vehicles, even with a robust carbon price. Models, do, however, tend to foresee a major role for electric vehicles in the medium term. For example, in the IEA World Energy Outloook's "450 scenario" (ambitious climate policies), natural gas vehicles account for just two per cent of light-duty vehicle sales by 2035, but pure electric and plug-in hybrid vehicles account for about 40 per cent.[216]

3.4.2 NATURAL GAS AS A COMPLEMENT TO RENEWABLES IN ELECTRICITY GENERATION

It is often argued that new natural-gas fired power plants, which have the ability to quickly adjust their power output, must be built as backup for any expansion of variable-output renewable sources like wind power. It is certainly true that in electricity grids that lack other "on demand" sources like hydropower, gas-fired plants may play an important role of complementing variable-output renewable energy.

There are, however, several reasons why a major expansion of variable-output renewable electricity need not be accompanied by increased consumption of natural gas in the electricity sector at the national or continental level. First, current electricity systems often have inherent redundancies that allow the integration of significant amounts of new variable-output sources.[217] Second, in cases where substantial natural gas-fired generating capacity is needed as backup, that capacity may only need to be utilized at a low average rate. Third, the need for backup gas-fired capacity can be reduced with improvements to electricity grids to make them "smart" – capable of integrating different power sources in a more sophisticated manner[218] – and to expand interconnections to locations with hydropower. (In Canada, this could mean stronger interprovincial connections to British Columbia, Manitoba and Quebec.) Fourth, in addition to hydroelectric facilities, emerging technologies such as flow batteries[219] and concentrating solar power[220] can use energy storage to smooth the output of energy from the wind and sun.

Although some economic models may not adequately address the need for backup power, the IEA's World Energy Model does so.[221] The "450 scenario" in the IEA's World Energy Outlook (see Section 3.2.1) provides an illustration of the points above in the case of the U.S. As shown in Table 10, natural gas-fired electricity generating capacity stays nearly flat between 2008 and 2035, while wind and solar capacity undergoes a massive expansion. Utilization of the gas-fired capacity rises considerably to 2030, but then falls off by 2035 to a point where more power is being generated from wind and solar than from gas.

Table 10. U.S. electricity generation in the IEA's World Energy Outlook 2010, 450 scenario[222]

ENERGY SOURCE		2008	2020	2030	2035
All	Generation (TWh)	4343	4572	4790	4876
Natural gas	Generation (TWh)	911	905	1317	735
	Share of generation (%)	21	20	27	15
	Generation capacity (GW)	409	392	427	428
Wind and solar	Generation (TWh)	59	316	813	1092
	Share of generation (%)	1	7	17	22
	Generation capacity (GW)	26	128	298	391

In addition, an increase in natural gas use in the electricity sector does not necessarily mean increased gas consumption in the whole economy. In the preceding example, although the amount of gas being used for electricity generation rises considerably between 2008 and 2030, declines elsewhere mean that total national gas consumption is at the same level in 2030 as it was in 2008.[223]

3.4.3 THE RISK OF "LOCK-IN" TO THE OUTCOMES OF INITIAL CLIMATE POLICY

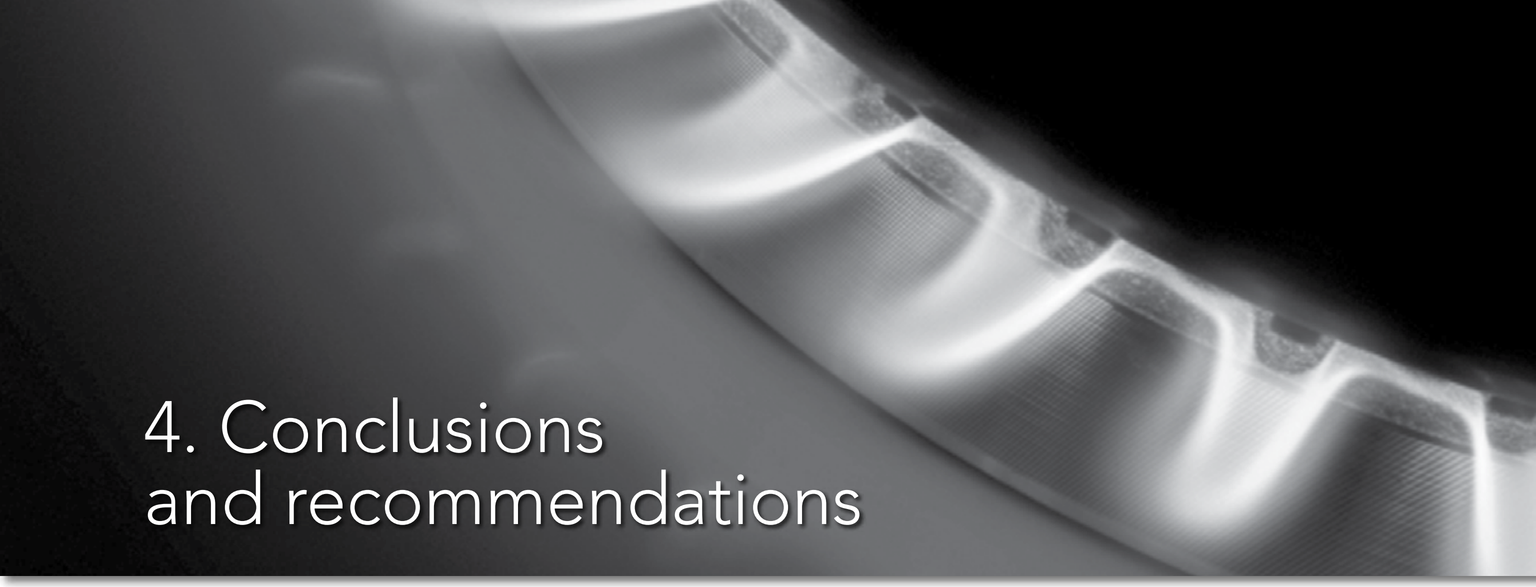
An issue that is not fully addressed in the scenarios developed in economic modelling studies, or in other proposals that focus on meeting near- or medium-term GHG targets, is the risk that if new infrastructure continues to be built for the production and use of natural gas without CCS, it may become a barrier to meeting long-term GHG objectives.

For example, as noted in Section 1.4, replacement of coal by natural gas in electricity generation could potentially make a significant contribution to meeting the near-term national GHG target to which the U.S. has committed (17 per cent below the 2005 level by 2020). But would the owners of new gas-fired power plants built in the next few years willingly cease to operate them – or accept the costs of converting them to CCS – soon after 2020, as the U.S. pushed for deeper GHG reductions? Even if gas-fired power plants need operate only for 20 years or so to justify their relatively low capital costs, their owners will nonetheless want them to generate revenues for as long as possible.

Recent comments by the IEA's Chief Economist, Fatih Birol, lend weight to this concern: Birol warns that efforts to tackle climate change through renewable energy are under threat from the unconventional gas revolution, and notes that the shale gas boom in the U.S. has contributed to a sharp drop in investment in renewable energy.[224] As noted earlier (see Table 10), the IEA's "450 scenario" does not significantly expand gas-fired electricity generation capacity in the U.S. but focuses instead on a long-term expansion of renewable electricity. However, in the near term it falls short of the U.S. GHG target for 2020.[225]

There are two further reasons to be reticent about building new infrastructure for the production and use of natural gas without CCS, even when economic models indicate that it is consistent with ambitious GHG reduction scenarios. First, modelling scenarios are generally based on a carbon price that starts low and steadily increases. But it can be argued that a more economically rational way to address climate change would be to adopt a fixed "budget" for total emissions between now and a distant year such as 2050, and then set the carbon price accordingly. (This could notionally be implemented using a cap-and-trade system with a single multi-decade compliance period.) Under this approach the carbon price would be high from the outset – and it could well rule out any new investments in natural gas combustion without CCS.

Second, recent science indicates that even at relatively low atmospheric GHG concentrations, the impacts of climate change may be much more severe than previously thought.[226] This suggests that governments need to do all they reasonably can to avoid *any* new sources of GHG emissions.[227]



4. Conclusions and recommendations

In Section 1.1, we posed three sequential questions (see Figure 1) that we believe are the most relevant for determining the optimal path for the production and use of natural gas. In this section we respond to each of these questions and provide recommendations.

4.1 The three questions

QUESTION 1:
Would well-designed climate policies strong enough to secure adequate GHG reductions in North America lead to a level of natural gas production and use that requires new production facilities?

Our review of economic modelling studies (Section 3.2) and the original modelling study commissioned for this report (Section 3.3) found that where policies are designed to be consistent with limiting average global warming to 2°C – the objective that governments have unanimously endorsed in the UN climate negotiations – North American or Canadian natural gas consumption is projected either to rise only a little above current levels or to decline. As noted in Section 1, and further discussed in Section 3.2, we take the view that LNG trade between North America and the rest of the world will not become a major factor in North American production decisions, in which case our production of natural gas should align closely to our consumption. This means that, given the significant decline in conventional gas production (see Figure 4), the answer to question 1 is "probably yes."

Before going further, however, we should note that there are good climate-related reasons for more reticence about building new infrastructure for the production and use of natural gas without CCS than the conclusions of economic modelling suggest (see Section 3.4.3). This is a topic that demands further exploration.

Having answered question 1 with a cautious yes, we need to address question 2.

QUESTION 2:

Is it technically and economically feasible to contain the non-climate environmental impacts at an acceptable level?

In Section 2.5 we identified a wide range of non-climate impacts from natural gas production and use, some of which represent major challenges. While a full assessment of the technical and economic feasibility of containing these impacts at an acceptable level was beyond the scope of this report, our analysis makes clear that a high level of caution is imperative in developing new natural gas production areas, especially where the gas is unconventional, and especially regarding cumulative impacts on the landscape, quality of life and water resources.

Assuming that the answer to question 2 is "yes" for some subset of natural gas production and use, then we must also address question 3.

QUESTION 3:

Would well-designed climate policies (see question 1) lead to a level of natural gas production and use that is higher or lower than the business-as-usual level?

The economic modelling studies described in Sections 3.2 and Section 3.3 deliver an unequivocal answer to this question: adequate climate policies will lead to a level of natural gas production and use that is lower than the business-as-usual level, in the near, medium and long term. In this sense, natural gas is *not* a bridging fuel in the fight to curb climate change.

4.2 Recommendations

The answers to our three questions, combined with other analysis in this report and elsewhere, lead us to the policy recommendations below. We recognize that as these recommendations cover a wide range of issues, they are fairly general. In some cases more research and analysis is needed to elaborate them further.

4.2.1 CONTAINING THE CLIMATE IMPACTS

First and foremost, federal and provincial governments need to implement climate policies capable of meeting their own GHG targets and Canada's international responsibilities. The Intergovernmental Panel on Climate Change (IPCC) has shown that to have a chance of not exceeding 2°C of average global warming, industrialized countries' combined GHG emissions must fall to 80 to 95 per cent below the 1990 level by 2050, if they are to make a fair contribution to the necessary cuts in global emissions.[228] Therefore:

RECOMMENDATION 1:

Federal and provincial governments should urgently produce and immediately begin implementing plans that are demonstrably capable, at a minimum, of (i) meeting their current GHG targets for 2020, and (ii) initiating a transformation of energy systems sufficient to reduce Canada's GHG emissions to 80 per cent below the 1990 level by 2050.

These plans should include, *inter alia*:[229]

- an economy-wide price on GHG emissions covering as many sources as practical, implemented as soon as possible and established by cap-and-trade systems, carbon taxes or both;
- regulations to minimize those emissions from natural gas production, processing and pipelines to which application of a carbon price is impractical;
- policies to accelerate energy efficiency improvements, including building codes, appliance efficiency standards and support for retrofits of existing buildings.

RECOMMENDATION 2:

Where governments approve new natural gas processing plants that strip significant volumes of CO_2 from raw gas, those plants should be required to capture and permanently store that CO_2 if they do not do so as a result of a carbon price.

As argued in Section 1.1, if the non-climate environmental impacts can be contained at an acceptable level, then the best guide to the optimal path of natural gas production and use is the expected outcome of climate policies that explicitly aim to achieve the necessary GHG reductions. But in the absence of adequate climate policies, we should be prepared to rely on other policies to follow our best estimate of the optimal path.

This recommendation is important because new gas processing plants, especially in British Columbia, could be a major source of new GHG emissions that would make it extremely difficult for the province to meet its GHG target for 2020.[230] Gas processing is the least costly application of CCS, with an estimated cost per tonne of CO_2 much lower than a carbon price sufficient to meet GHG targets.[231] This means that gas producers would be expected to implement CCS if such a carbon price were in place.

RECOMMENDATION 3:

In the absence of policies strong enough to meet the national and provincial GHG targets above, government approvals of new production facilities should be consistent with a lower level of natural gas production and use than would otherwise occur.

Our answer to question 3 above was that adequate climate policies will unequivocally lead to a level of natural gas production and use that is lower than the business-as-usual level. But as above, in the absence of adequate climate policies, we should be prepared to rely on other policies to follow our best estimate of the optimal path.

Therefore, put simply, governments should not be approving gas production levels that are incompatible with their GHG targets, especially since production is likely to cause substantial non-climate environmental impacts.

4.2.2 MITIGATING AIR POLLUTION

RECOMMENDATION 4:

Government approvals of natural gas-fired turbines should require the implementation of best available technology to limit emissions of air pollutants, including selective catalytic reduction to reduce NO_x emissions.

In Section 2.5.1, we noted that natural gas combustion appears to make a significant contribution to Canadian emissions of NO_x, but that these can be largely eliminated, at low cost, using selective catalytic reduction (SCR). SCR has been required by the U.S. EPA on all combined cycle natural gas power plants in the past several years.

4.2.3 MITIGATING THREATS TO WATER

As described in Section 2.5.2, natural gas development poses significant risks to water resources, especially as a result of the volumes used for hydraulic fracturing, and the risk of spills or inadequate disposal of wastewater. Therefore:

RECOMMENDATION 5:

Governments should review, strengthen as needed, and strictly enforce requirements regarding water monitoring, use and treatment, as well as the liability of producers in case of contamination, to ensure the sustainability of water resources in regions targeted for natural gas development.

RECOMMENDATION 6:

Federal, provincial and territorial governments should undertake improved public mapping of groundwater to allow for informed environmental assessment of oil and gas exploration and production.

RECOMMENDATION 7:

Natural gas producers should be required to publicly disclose the chemical composition of hydraulic fracture fluids, and report injected fluids under the National Pollutant Release Inventory.

The risk of fracture fluids contaminating fresh water directly, via the fractured rock, appears to be low in most settings. However, since fracture fluids are introduced into the environment, there is a fundamental public right to know their composition. Although companies are generally required to report substances injected underground to Canada's National Pollutant Release Inventory (NPRI), fracture fluids escape this provision as oil and gas wells are currently exempted from the NPRI.

4.2.4 PUBLIC ENGAGEMENT AND ENVIRONMENTAL ASSESSMENT

RECOMMENDATION 8:

Governments should not permit the introduction of shale gas production

- *unless thorough public consultation indicates a high level of acceptance by concerned citizens, and unless producers are required to transparently provide residents with fair compensation for the impacts;*
- *in areas where the natural environment or traditional land use are of special value.*

As noted above in our answer to question 2, the analysis in Section 2.5 makes clear that a high level of caution is imperative in developing new natural gas production areas.

In particular, a region targeted for shale gas development will be subject to intense industrialization, with hundreds or thousands of wells drilled annually, a well pad roughly every square mile, considerable additional infrastructure, and the inevitability of accidents. Without the help of governments, citizens' interests are likely to carry little weight compared to those of producers.

Proceeding with a high level of caution means obtaining the fullest possible information and conducting thorough, transparent and unbiased assessments before giving a green light to development. Currently, information is lacking. For example, the U.S. Council of Scientific Society Presidents wrote in May 2010: "The development of methane from shale formations is another example where policy has preceded adequate scientific study."[232] Quebec's national public health institute recently concluded that the scientific literature "does not currently permit an evaluation of the risks to public health" from shale gas development in the province.[233] Similarly, Canadian regulatory authorities generally have only a limited understanding of the structure and use of groundwater resources (see Section 2.5.2).

RECOMMENDATION 9:

Natural gas production should be brought under normal provincial environmental assessment processes, recognizing that multiple wells may be assessed as a single project for reasons of practicality. Environmental assessments should consider roads, pipelines and other infrastructure necessitated by gas production.

It is clearly unacceptable that most natural gas wells in Canada are currently exempted from the normal environmental assessment process (see Section 2.6). There is no compelling reason why gas development should be exempted from standards of assessment that governments deem to be necessary for other kinds of industrial development.

However, while typical environmental assessments looking at small production increments are necessary, they are not sufficient because they cannot reach conclusions about the total, or cumulative, impacts of development.

RECOMMENDATION 10:

Provincial and territorial governments should undertake and publish comprehensive and ongoing assessments of existing and anticipated cumulative environmental impacts in regions targeted for natural gas development. Ideally these assessments should be part of a legislated system of regional land-use plans specifying clear limits on cumulative environmental impacts; this system should require

- *frequent monitoring and public reporting of cumulative impacts;*
- *approvals of industrial projects (such as natural gas production) to be consistent with the limits on impacts, as measured by the monitoring program.*[234]

RECOMMENDATION 11:

Provinces and territories should give full responsibility for the development and enforcement of environmental safeguards for natural gas production (as well as other extractive industries) to environment ministries, not natural resource ministries or other regulatory agencies.

Proceeding with a high level of caution in developing new natural gas production also means handing control to the most appropriate regulatory bodies. Environment ministries exist because the development and enforcement of environmental safeguards requires institutions that are fully focused on that task. Regulatory bodies that have a role promoting oil and gas development face a conflict of interest if they are also responsible for environmental safeguards that may make development more difficult.

4.2.5 ELIMINATING PERVERSE INCENTIVES

RECOMMENDATION 12:
Governments should not provide financial support for the replacement of coal or petroleum products by natural gas.

In light of our answer to question 3 above, governments should not be subsidizing the expansion of natural gas use. In specific applications where increased gas use may be compatible with GHG targets, it is preferable to achieve this outcome with carbon pricing or sector-specific regulation, and reserve scarce public funds for the most sustainable energy solutions: conservation, efficiency and renewable energy.

RECOMMENDATION 13:
Royalty regimes must be adjusted as needed to ensure that provincial and territorial governments collect the maximum value of the natural gas resource, allowing for a fair return on investment for producers.

Royalty and tax regimes for natural gas production must reflect the public interest. Citizens are the owners of the resource, and royalties are the mechanism by which governments collect the value of the resource on citizens' behalf. If governments fail to collect the maximum value, they are short-changing citizens and providing an unjustifiable subsidy to producers.[235]

RECOMMENDATION 14:
Federal, provincial and territorial governments should eliminate all tax incentives for oil and gas production, measured relative to a neutral tax system.[236]

Oil and gas producers are also subsidized through the tax system. There is no good reason for such subsidies, which increase a wide range of environmental impacts. Along with other G20 countries, Canada committed in 2009 to eliminate subsidies for fossil fuels "over the medium term," but it has shown no sign of implementing this commitment.[237]

NOTES

1 After the U.S., China, Russia and Saudi Arabia. See U.S. Energy Information Administration, *International Energy Statistics*, http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=44&pid=44&aid=1 (accessed September 25, 2010).

2 After the U.S. and Russia. See U.S. Energy Information Administration, *International Energy Statistics*, http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=3&pid=26&aid=1 (accessed September 25, 2010).

3 Statistics Canada, *Energy Statistics Handbook, First Quarter 2010* (Ottawa, ON: Statistics Canada, 2010), 32. Available at http://www.statcan.gc.ca/pub/57-601-x/57-601-x2010001-eng.pdf.

4 Primary energy means energy in its relatively raw forms, notably coal, petroleum, natural gas and electricity produced from non-fossil sources. Electricity produced from fossil fuels is secondary energy.

5 Statistics Canada, *Report on Energy Supply and Demand in Canada – 2008* (Ottawa, ON: Statistics Canada, 2010), 29. Available at http://www.statcan.gc.ca/pub/57-003-x/57-003-x2008000-eng.pdf.

6 National Energy Board, *2009 Natural Gas Exports and Imports Summary*, http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/sttstc/ntrlgsxprt/ntrlgssmmr/2009/smmry2009-eng.html (accessed September 25, 2010).

7 See Jennifer Grant, *Defending the North* (Drayton Valley, AB: The Pembina Institute, 2010). Available at http://www.pembina.org/pub/1986.

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21 This is a rough estimate obtained by taking all the CO_2 emissions from burning fossil fuels in Canada's 2008 national GHG inventory, and reducing emissions from

coal-fired electricity generation by 60%, oil-fired electricity by 30%, and all vehicles by 30%. This likely overestimates the emission reductions in vehicles (see Section 3.4.1), but neglects emission reductions in industry and buildings, where we have assumed that natural gas is the only fuel currently used (it does already account for the majority of emissions in these sectors). This calculation does not consider non-combustion GHG emissions from the production, processing and transport of fossil fuels, but they are generally accepted to be much less than the emissions from fuel combustion (see Section 2.4). The GHG inventory report is *National Inventory Report 1990–2008: Greenhouse Gas Sources and Sinks in Canada* (Gatineau, QC: Environment Canada, 2010). Available at http://www.ec.gc.ca/Publications/default.asp?lang=En&xml=492D914C-2EAB-47AB-A045-C62B2CDACC29.

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28 These figures include small amounts of fossil fuels used as chemical feedstocks and for other non-energy purposes.

29 Statistics Canada, *Report on Energy Supply and Demand in Canada – 2008*, 29.

30 U.S. Energy Information Administration, *Annual Energy Review 2009*, 9. We have used the factors on p.370 to recalculate the value for non-fossil electricity to be equivalent to energy generated, consistent with Statistics Canada's approach.

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32 Statistics Canada does not provide comprehensive data on biomass energy.

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35 U.S. Energy Information Administration, *Annual Energy Review 2009*, 195, 33.

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46 U.S. Energy Information Administration, *Annual Energy Outlook 2011*, 115. As in Table 1, we have recalculated non-fossil electricity's contribution to total primary energy to be equivalent to energy generated.
47 This 30% figure differs from the 31% in Table 1 because the National Energy Board and Statistics Canada differ slightly in their calculations.
48 This 26% figure differs from the 25% in Table 1 because the U.S. data here is calculated slightly differently (e.g., it appears not to include fossil fuels used for non-energy purposes).
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51 U.S. Energy Information Administration, *Annual Energy Review 2009*, 7. As in Tables 1 and 3, we have recalculated non-fossil electricity's contribution to total primary energy to be equivalent to energy generated.
52 Includes crude oil and natural gas liquids.
53 Statistics Canada does not provide comprehensive data on biomass energy.
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Our energy systems must change if we are to combat climate change. Many people are asking whether natural gas can play a role as a “bridging” fuel that enables near-term reductions in the greenhouse gas emissions responsible for climate change. This report explores the role of Canada’s federal and provincial governments in shaping future production and use of natural gas in consideration of both the climate and non-climate environmental impacts, and offers recommendations.

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