Shale Gas in British Columbia

Risks to B.C.'s climate action objectives

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About the Pembina Institute

The Pembina Institute is a national non-profit think tank that advances sustainable energy solutions through research, education, consulting and advocacy. It promotes environmental, social and economic sustainability in the public interest by developing practical solutions for communities, individuals, governments and businesses. The Pembina Institute provides policy research leadership and education on climate change, energy issues, green economics, energy efficiency and conservation, renewable energy, and environmental governance. For more information about the Pembina Institute, visit www.pembina.org or contact info@pembina.org. Our engaging monthly newsletter offers insights into the Pembina Institute's projects and activities, and highlights recent news and publications. Subscribe to Pembina eNews: http://www.pembina.org/enews/subscribe.

About the Author

Matt Horne has been with the Pembina Institute since 2003 and is currently the Director of B.C. Energy Solutions. His focus is on policy change that will reduce greenhouse gas emissions in British Columbia and provide replicable models for the rest of Canada. In pursuit of this goal, he has worked on initiatives with the province, municipalities and First Nations. Prior to joining Pembina, Matt worked extensively with energy-economy models on projects attempting to estimate the costs and benefits of climate change policy in Canada. Matt holds a Bachelor of Engineering from Dalhousie University and a Master of Resource and Environmental Management from Simon Fraser University.

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1. Introduction

British Columbia has been extracting natural gas for half of a century but until recently, conventional wisdom held that the province's economic gas reserves would be significantly depleted by 2020; the readily accessible gas was running out and other reserves were either too remote or too costly to extract. That notion has been challenged in the past several years because the costs of extracting hard-to-access sources of gas, notably shale gas, have dropped significantly. The impacts are far-reaching, as it is now known that B.C. is located on top of gas reserves that are significant not only provincially but also on a continental scale.

Shale gas is an unconventional type of gas, with reserves trapped in geological formations that make it difficult to extract.[1] The reservoir characteristics of conventional gas are such that the gas flows readily from the formation to a well. However, unconventional gas extraction relies upon a combination of techniques that were not technically or economically feasible in the past.[2] The most important of these techniques are:

1. Hydraulic fracturing, which involves injecting pressurized water, gases, chemicals and sand into gas wells to break apart the rock and allow the gas to flow more easily; and
2. Directional drilling, which allows multiple wells to be drilled from a single well pad.

B.C.'s shale gas reserves are found in the northeast, of which most drilling activity has been concentrated in two main deposits: the Montney Basin near Dawson Creek and the Horn River Basin near Fort Nelson.[3] The gas contained in these deposits is not identical. Notably, the natural gas found in the Horn River Basin contains a much higher level of carbon dioxide (referred to as formation carbon dioxide) that needs to be removed from the gas before it can be shipped to end-users.[4] The implications of this difference are discussed in Section 5.2.

According to projections from the Canadian Association of Petroleum Producers (CAPP), production from Horn River and Montney Basins could account for 22% of North American shale gas production by 2020 (see Figure 1). The combined 52 billion cubic metres per year (5 billion cubic feet per day — labeled Bcf/d in the figure) that is forecast to be produced from the

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[1] Coalbed methane is another form of unconventional gas development. For more information, see: West Coast Environmental Law, "Coalbed Methane: A citizen's guide," May 2003, http://www.wcel.org/resources/publication/coalbed-methane-citizens-guide

[2] These individual techniques are sometimes mistakenly referred to as new, but it is the industry's combined abilities to use them at scale and with relatively low cost that has made shale gas economically attractive for producers.

[3] In some publications, the Montney Basin is referred to as tight gas, which is another type of unconventional natural gas. However, unlike typical tight-gas plays, the natural gas in the Montney is sourced from its own organic matter, which is more typical of shale gas. For simplicity, and following the approach used in the National Energy Board's comparison of Canadian shales, this report characterizes the Montney Basin as shale gas.

[4] The environmental impact of formation carbon dioxide is the same as that of carbon dioxide from burning fossil fuels. The difference is that it is produced when carbon dioxide has been stripped from raw natural gas, as opposed to being a by-product of combustion.

Horn River and Montney Basin in 2020 is equivalent to 70% of all the gas that was used in Canada in 2010.[5] However, it is important to acknowledge that this is just one forecast for natural gas development, and actual (as opposed to forecast) development will depend on a number of factors, such as the market price for natural gas as well as any relevant environmental policies.

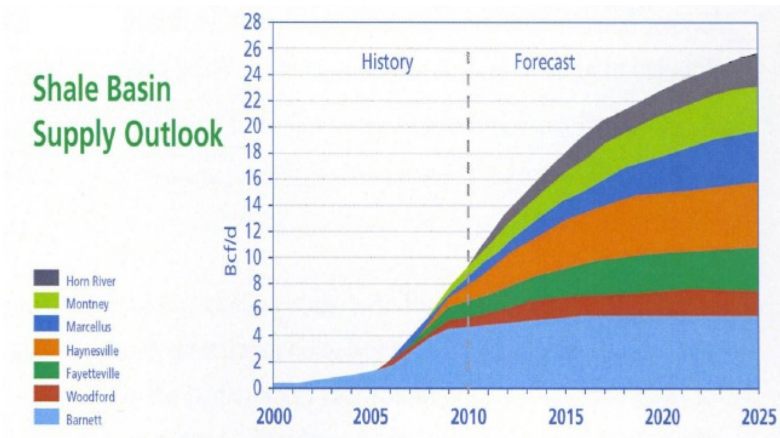

Figure 1 — Projected gas extraction for Canadian and U.S. shale gas reserves[6]

The shift to shale gas in North America is already well underway. The Barnett Shale in Texas has been subject to hydraulic fracturing and gas extraction since the late 1990s. Likewise, companies have begun to extract gas from the Marcellus Shale, which is located underneath the states of New York, Pennsylvania, Ohio and West Virginia.

While a shift to shale gas began relatively recently in B.C., these sources still accounted for as much as 39% of the province's natural gas production in 2008, predominantly from the Montney Basin.[7] The economic potential of exploiting the province's shale gas reserves has been well documented. As an illustration, the province is counting on $1.8 billion in revenue from gas royalties and leases in 2013/14 — or four per cent of forecasted provincial revenues.[8]

Jurisdictions with shale gas reserves are clearly attracted to the potential economic benefits that the resource offers, however, in some regions health and environmental concerns are beginning to dominate the debate, particularly because of potential contamination of ground and surface water resources. Quebec[9], Maryland[10], South Africa[11] and France[12] have all recently placed

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[5] Canadian Gas Association, "Natural Gas Sales and Exports" found at: www.cga.ca/resources/gas-stats/

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

[7] BC Ministry of Energy Mines and Petroleum Resources, "Shale Gas Activity in British Columbia: Exploration and Development of BC's Shale Gas Areas,", Presentation to the 4th Annual Unconventional Gas Technical Forum, April 8, 2010, slide 7, www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalGas/Documents/C%20Adams.pdf

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

[9] Développement durable, Environnement et Parcs, "Développement durable de l'industrie des gaz de schiste au Québec," 2011, http://www.mddep.gouv.qc.ca/communiques_en/2011/c20110308-shale-gas.htm

temporary or indefinite moratoriums on hydraulic fracturing until the risks are better understood. The United States Environmental Protection Agency is also undertaking a major study to understand the impacts of hydraulic fracturing.[13]

Health and environmental concerns from gas development are not new to B.C., where the northeast of the province has lived with oil and gas development for over 50 years. There have been long-standing concerns about gas development fragmenting the provincial landscape and endangering species that rely on those ecosystems (e.g., boreal caribou).[14] Numerous concerns have also been raised about the potential health impacts of sour gas leaks, including a recent call for a public health inquiry to investigate whether current regulation of oil and gas development adequately protects public health.[15] The call for that inquiry was supported by First Nations, landowners, and a range of organizations.

Depending on the pace and scale of development, shale gas extraction could exacerbate these concerns. It also raises two additional environmental concerns that have been receiving increasing attention in B.C.:

- **Water Impacts**. Hydraulic fracturing typically requires large volumes of water, placing additional stress on fresh water systems. Further, the water used for fracturing is contaminated through the process and cannot be returned to fresh water systems.
- **Climate impacts**. Extracting and processing natural gas produces greenhouse gas (GHG) emissions, with the total accounting for 21% of B.C.'s emissions (13.3 million tonnes).

Climate impacts are the focus of this report.

This paper follows the approach of, and reaches similar conclusions to, a recent study by Mark Jaccard and Brad Griffin (2010).[16] It builds on this earlier work by broadening the scope of study beyond formation carbon dioxide that would be contained within, and eventually emitted from, natural gas from the Horn River region. This report accounts for a broader set of emissions

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[10] Maryland General Assembly, "House Bill 852," 2011, http://mlis.state.md.us/2011rs/billfile/hb0852.htm

[11] S. Tavanger, "South Africa imposes fracking moratorium," *Platts Energy Week,* April 25, 2011, http://plattsenergyweektv.com/story.aspx?storyid=147836&catid=293

[12] T. Patel, "The French Public Says No to '*Le Fracking*'," *Bloomberg Businessweek*, March 31, 2011, http://www.businessweek.com/magazine/content/11_15/b4223060759263.htm

[13] The first stage of the EPA's work will be completed in late 2012 and is described in their draft study plan — Environmental Protection Agency, "Draft Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources", February 2011. Available at: http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/HFStudyPlanDraft_SAB_020711-08.pdf

[14] For example: Forest Practices Board, "A Case Study of the Kiskatinaw River Watershed — an Appendix to Cumulative Effects: From Assessment towards Management," 2011, p. 9 and Appendix 2, http://www.fpb.gov.bc.ca/SR39_CEA_Case_Study_for_the_Kiskatinaw_River_Watershed.pdf

[15] Letter from University of Victoria Environmental Law Centre on behalf of the Peace Environment and Safety Trustees Society, February 2, 2011, (accessed March 29, 2011), http://www.elc.uvic.ca/documents/11%2002%2002%20Ltr%20to%20Hansen%20re%20Inquiry%20(final%20and%20SIGNED).pdf

[16] M. Jaccard & B. Griffin, "Shale gas and climate targets: can they be reconciled?" *Pacific Institute for Climate Solutions*, 2010

sources (e.g. the emissions from burning natural gas in compressor stations and gas processing plants), and the emissions associated with gas extracted from the Montney Basin.

The Greenhouse Gas Reduction Targets Act of 2007 put limits on B.C.'s emissions[17] and Premier Christy Clark has affirmed those objectives.[18] While there are no sector-specific targets, every sector of the economy (including natural gas) needs to fit within a plan that results in a steep reduction in emissions.

Emissions from the gas sector have been increasing rapidly over time — up 85% since 1990 — so transitioning to a situation in which they are declining represents a significant change.[19] Achieving that degree of change (and the province's climate objectives) will be particularly challenging for two reasons:

1. Recoverable shale gas reserves in B.C. are immense and it is anticipated that the shift to shale will lead to higher levels of overall gas production in the province. With all else being equal, increased production will lead to higher overall GHG emissions for B.C.
2. The projected increase in gas extraction from the Horn River basin will result in the release of much more formation carbon dioxide when the gas is processed. Barring the deployment of carbon capture and storage technologies, this will lead to increased emissions relative to historical trends.

The net effect is that the anticipated development of natural gas reserves in the province will make it more difficult for B.C. to meet its GHG emissions reduction targets — if it does not compromise those targets altogether. Significant government and industry action will be required to overcome these challenges.

The body of this report is organized as follows:

- Section 2 provides an overview of the GHG emissions produced by B.C.'s natural gas sector.
- Section 3 discusses the general opportunities that are available to reduce those emissions.
- Section 4 and 5 estimate anticipated emissions in 2020, accounting for current and proposed climate action policies as well as the anticipated shift to shale gas. While this report attempts to draw on the most recent research available, it is important to acknowledge that many knowledge gaps still exist and there is considerable uncertainty and variability in the data.
- Section 6 recommends ways in which the province can improve its planning and regulatory framework for shale gas development to enable that development to align with the province's climate objectives.

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[17] The province's legislated targets are six per cent below 2007 levels by 2012, 18% below 2007 levels by 2016, 33% below 2007 levels by 2020 and 80% below 2007 levels by 2050.

[18] For more information see Premier Christy Clark's open letter to British Columbians regarding B.C.'s leadership in the green economy. May 6, 2011, http://www.newsroom.gov.bc.ca/downloads/Letter_to_editor_May6-2011.pdf

[19] Calculated from Table A15-20 from Part 3 of Environment Canada's National Inventory Report: 1990 to 2009 — United Nations Framework Convention on Climate Change (UNFCCC), "National Inventory Submissions 2011," Canada,
http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5888.php

2. Anatomy of emissions from British Columbia's gas sector

Greenhouse gas emissions are produced at every stage of the process from the point when natural gas is removed from the ground to the point when it is eventually burned. Figure 2 and Figure 3 provide estimated breakdowns of the emissions from British Columbia's gas sector. The specific emissions for any individual company depend on the geology in which the gas is located, the composition of the raw gas, the proximity to water and other key inputs, the proximity to processing and transmission infrastructure as well as the technologies, processes and sources of energy relied upon to extract, transport and process the gas.

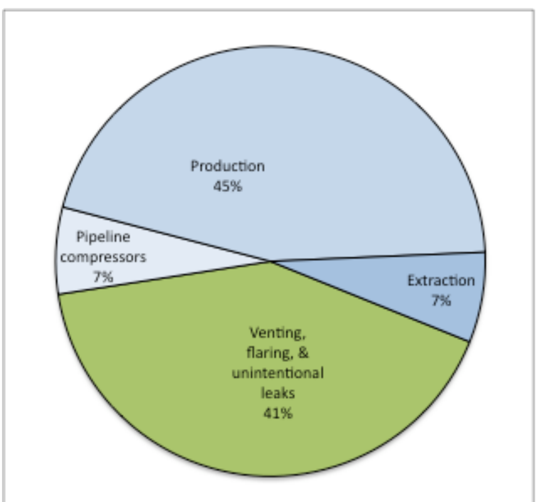

Figure 2 — Distribution of emissions from B.C.'s natural gas sector based on Canada's greenhouse gas inventory[20]

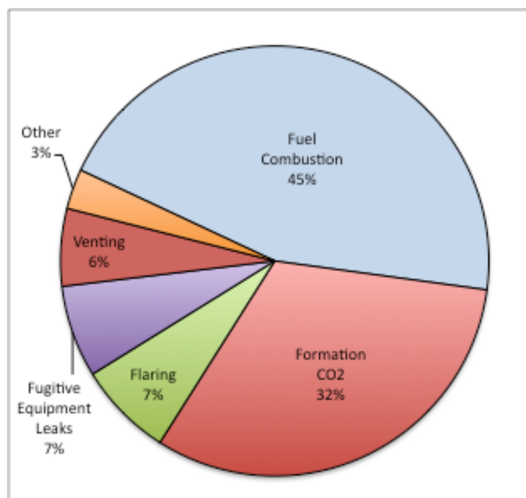

Figure 3 — Distribution of emissions from B.C.'s natural gas sector based on CAPP data[21]

Direct comparisons between data sets (Environment Canada and the Canadian Association of Petroleum Producers) are difficult for two reasons. First, as shown in Figure 2 and Figure 3, they

[20] Calculated from Table A15-20 from Part 3 of Environment Canada's National Inventory Report: 1990 to 2009 — United Nations Framework Convention on Climate Change (UNFCCC), "National Inventory Submissions 2011," Canada.

[21] The data is based on 2000 figures, the most recent in the following study — The Canadian Association of Petroleum Producers (CAPP), "A national inventory of greenhouse gas (GHG), criteria air contaminant (CAC) and hydrogen sulphide (H2S) emissions by the upstream oil and gas industry," 2004

categorize emissions differently. Second, the estimate of gas sector emissions from CAPP is 71% of the value provided by Environment Canada. That said, the pie slices that are different shades of blue (three in Figure 2 and one in Figure 3) are the emissions associated with fuel combustion and are roughly comparable between data sources.[22] See Appendix 1 for a more complete listing of the specific sources of emissions from the natural gas sector.

The majority of GHG emissions in the sector come from burning fossil fuels. This includes burning natural gas for energy demands in gas processing plants, compressor stations and well-head operations. Natural gas is also flared for a variety of purposes, such as enabling well maintenance and controlling pressure at wellheads. These sources account for between 52 and 66% of the sector's emissions. According to Environment Canada, the largest source of combustion emissions is production, accounting for 45% of the sector's total emissions.

A significant proportion — between 34 and 48% — of the natural gas sector's total emissions also comes from non-combustion sources[23]. These non-combustion sources include the intentional venting of natural gas and carbon dioxide from natural gas wells, pipelines and processing facilities as well as the unintended leakage of natural gas from the same infrastructure and facilities.[24] The largest single source of the sector's non-combustion emissions, accounting for 32% of the sector's emissions based on CAPP data, is the formation carbon dioxide removed from raw natural gas and vented from natural gas processing plants to make the gas suitable for end-users.[25]

Relating to Figure 2, B.C. and Canada's GHG inventories do not clearly separate the emissions from B.C.'s natural gas sector. They contain the following categories that collectively include (but are not limited to) the sector's emissions: fossil fuel production and refining; mining, oil and gas extraction; pipelines; as well as oil and natural gas fugitive sources. Appendix 2 details how values in Canada's GHG inventory were translated into those shown in Figure 2 (and Figure 4). The data is based on 2009 figures, the most recent in the inventory, but some estimates need to be made to isolate the natural gas sector from some emissions associated with oil production and mining. Also of note, the 'fugitives' category includes the intentional and unintentional non-combustion emissions described above (i.e., vented and leaked methane and formation carbon dioxide). Because industry typically uses the term "fugitives" to describe unintentional emissions (or leaks), this categorization can be misleading.

Figure 4 shows how the total emissions from the sector have changed over time, with total emissions from the sector increasing from 7.2 million tonnes of GHG emissions in 1990 to 13.3

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[22] Data from B.C.'s emissions reporting regulation is expected to be available in 2011 and the finer resolution of data it will provide should help resolve some of the discrepancies between data sources.

[23] This breakdown between combustion and non-combustion sources of GHG emissions is for the entire gas sector in B.C. and it will vary between companies and segments of the sector. For example, a processing plant that is processing raw gas with high levels of formation carbon dioxide will have a higher percentage of non-combustion sources.

[24] Non-combustion emissions are not limited to the natural gas sector. They also include methane released from landfills and methane escaping from coal during mining and handling.

[25] The data is based on 2000 figures, the most recent in the following study — The Canadian Association of Petroleum Producers (CAPP), "A national inventory of greenhouse gas (GHG), criteria air contaminant (CAC) and hydrogen sulphide (H2S) emissions by the upstream oil and gas industry," 2004

million tonnes in 2009 (using data from Canada's GHG inventory).[26] In that time period, they also increased from 14% of B.C.'s total emissions to 21%.

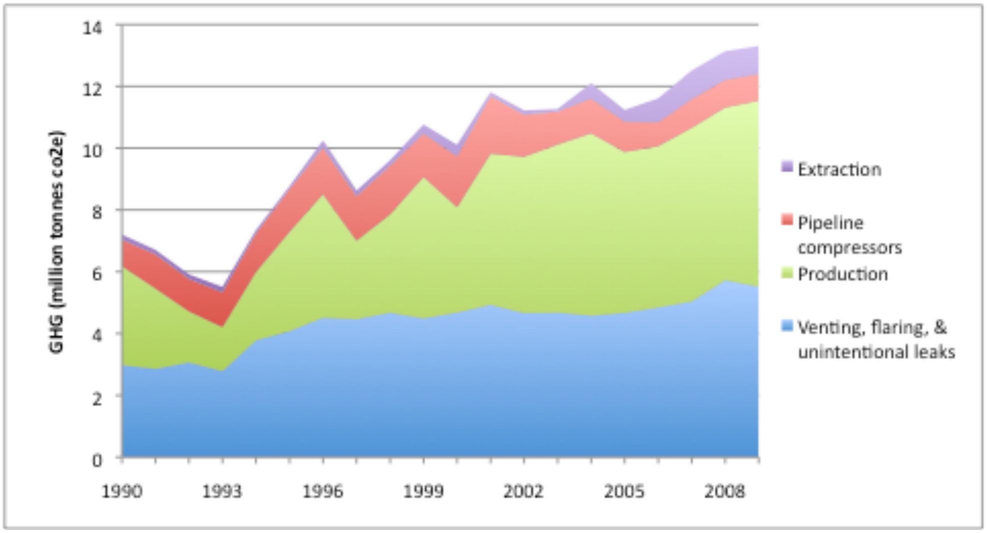

Figure 4 — Annual greenhouse gas emissions from B.C.'s natural gas sector

The rules for allocating and reporting emissions sources means that Figure 2, Figure 3 and Figure 4 do not include the following sources of emissions associated with the gas sector:

- electricity use,[27]
- transportation demands,[28] and
- end-uses, such as heating, transportation, or electricity generation (see Figure 5).

These sources either fall in other parts of B.C.'s emissions inventory (e.g., transportation emissions are not separated into specific sectors of the economy) or the emissions inventories of other jurisdictions (e.g., electricity imported from Alberta is included in Alberta's inventory).

Figure 5 illustrates the approximate magnitude of end-use emissions, such as heating, transportation, electricity generation or industrial processes, compared to the emissions from extracting, processing and transporting the natural gas, but not including the emissions associated

[26] Calculated from Table A15-20 from Part 3 of Environment Canada's National Inventory Report: 1990 to 2009 — United Nations Framework Convention on Climate Change (UNFCCC), "National Inventory Submissions 2011," Canada.

[27] The electricity used in B.C.'s natural gas sector comes from three sources: 1) the BC Hydro grid, which is predominantly hydro-powered, 2) self-generation in the sector using natural gas, 3) BC Hydro's Fort Nelson generating station (a single cycle gas turbine not connected to the main BC Hydro grid), which is the main source of electricity in the Fort Nelson region, and 4) the Alberta grid, which is predominantly powered by natural gas and coal and an additional source of electricity in Fort Nelson. A breakdown of the electricity used by each source and the resulting emissions is not available. BC Hydro's share of the energy demand in the gas sector is relatively small. The gas sector currently self-supplies most of its work energy requirements using direct drive motors.

[28] B.C.'s transportation emissions are significant (15 and four million tonnes for on-road and off-road sources in 2009 respectively), but no breakdowns by sector are provided.

with electricity use or transportation.[29] The end-use emissions are four times larger than the upstream extraction and processing emissions and 20 per cent less than B.C.'s total provincial emissions in 2009 (64 million tonnes).[30] The natural gas that is consumed in B.C. is included in the province's emissions inventory, but Environment Canada and B.C.'s Ministry of Environment do not account for the emissions that result from fossil fuels consumed in other jurisdictions.

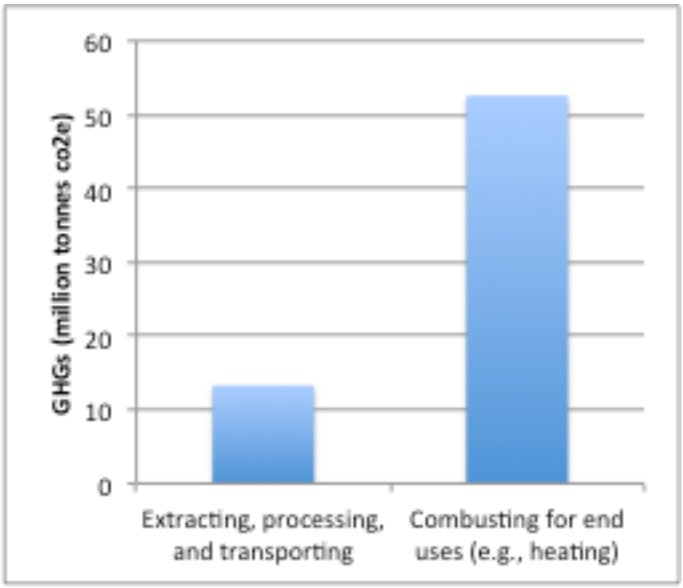

Figure 5 — Upstream greenhouse gas emissions vs. end-use greenhouse gas emissions (annual)

In the short to medium-term, the impact of those end-use emissions could be positive or negative. On the positive side, combustion of natural gas produces considerably less carbon dioxide 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. For example, natural gas can help to reduce emissions if it is used to replace coal-fired electricity generation. Conversely, increased availability of natural gas can also increase emissions if it prevents or delays the adoption of renewable energy sources or energy conservation and efficiency improvements.

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[29] The 'Extracting, processing and transporting' bar is calculated from Table A15-20 from Part 3 of Environment Canada's National Inventory Report: 1990 to 2009 —United Nations Framework Convention on Climate Change (UNFCCC), "National Inventory Submissions 2011," Canada. The 'Combusting for end uses (e.g., heating)' bar shows what the emissions would be if all the marketable natural gas produced in B.C. in 2009 was burned for heating. The marketable natural gas figure was obtained from National Energy Board statistics (http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/sttstc/mrktblntrlgsprdctn/mrktblntrlgsprdctn2009.xls). A hypothetical example is provided because no specific statistics on the end uses of B.C.'s gas are available. The size of the bar would shift marginally if the end use was different (e.g., electricity generation).

[30] Calculated from Table A15-20 from Part 3 of Environment Canada's National Inventory Report: 1990 to 2009 — United Nations Framework Convention on Climate Change (UNFCCC), "National Inventory Submissions 2011," Canada.

In the absence of meaningful, continent-wide climate change policies, it is impossible to assess the degree to which exports of natural gas from B.C. will help or hinder emissions reductions efforts. Because of that ambiguity, governments need to avoid assuming fossil fuel exports will help other jurisdictions reduce emissions and instead place a high priority on meeting their domestic targets.

Furthermore, it is clear that demand for natural gas will have to decline in the long-term if Canada and the U.S. are going to achieve deep cuts in greenhouse gas emissions.[31] This is because even a full-scale switch from all coal and oil use to natural gas would not come close to achieving the 80%-plus reductions in developed countries' greenhouse gas emissions (relative to a fixed recent level) that the Group of Eight (G8) heads of government have agreed are needed by 2050. That agreement is based on scientific analysis of what would be needed to avoid the worst impacts of human induced climate change.

Similar conclusions have been reached in scenarios looking at less stringent efforts to reduce greenhouse gas emissions. A review of modelling studies found that weak, near-term climate policy results in less natural gas consumption, continent-wide, than scenarios without any efforts to reduce greenhouse gas emissions.[32] The reason for this conclusion is that even if climate policy stimulates some switching to natural gas (e.g. coal-fired electricity generation switching to natural gas), economy-wide this is more than counteracted by the more energy efficient use of natural gas and an expansion of renewable energy.

Based on these conclusions, there is a strong rationale for B.C. to prepare for a time when there will be slowing, and eventually decreasing, demand for natural gas. The only way B.C. can justify business as usual growth in natural gas exports to the U.S. is by counting on a continued U.S. failure to implement climate policy, which would be counting on a policy scenario contradictory to B.C.'s efforts to tackle climate change.

[31] M. Bramley, "Is natural gas a climate solution for Canada?" the Pembina Institute, 2011.

[32] Ibid.

3. Opportunities to reduce emissions

For British Columbia to meet its short-, medium- and long-term greenhouse gas emission reduction targets the emissions from the natural gas sector need to decline significantly — along with the emissions from all sectors. This section provides a brief introduction to four possible ways to reduce emissions from the natural gas sector. It is not a comprehensive list and is not intended to provide a detailed assessment of the emissions reduction potential, technical feasibility or cost-effectiveness of the options. Nor does it assess the economic implications of encouraging or requiring any of the potential solutions. Recognizing those limitations, the options include:

1. Reducing the amount of natural gas consumed or lost in extraction and production.
2. Using cleaner energy sources to extract and produce natural gas.
3. Preventing emissions from reaching the atmosphere.
4. Limiting the amount of natural gas extracted and processed.

Some of these solutions are already being deployed because they are cost-effective for companies, and because policies that the province has already implemented as part of its Climate Action Plan have mandated the solutions or made them cost-effective. That said the solutions are not being deployed at a significant enough scale to reduce emissions in line with the province's climate change targets based on current economic conditions and implemented policies.

Although it does not help reduce emissions in the natural gas sector, end-use emissions (e.g., from heating, transportation, or electricity generation) can, and should, also be reduced. Switching to cleaner energy sources (e.g., ground- or air-source heat pumps) or using natural gas more efficiently (e.g., with high-efficiency condensing furnaces and/or better insulated homes and buildings) can help to accomplish these reductions. In either case, the end-user gets the same service (e.g., a well heated home), but needs less natural gas to achieve that result. In many cases, these types of solutions can result in dramatic reductions in the combustion of natural gas (and other fossil fuels) and the resulting greenhouse gas emissions. There are also cases where increased end-use of natural gas can help reduce emissions (e.g., using natural gas instead of coal to generate electricity).

3.1 Reducing the amount of natural gas consumed or lost

Natural gas is consumed and lost in the extraction and production process and it is in the industry's interest to minimize the amount consumed or lost. That said there are often solutions that allow less gas to be consumed or lost that are not currently being used because they are often considered to be uneconomic when an investment decision is made. The impact of reducing natural gas consumption or losses within the natural gas sector is fewer GHG emissions per unit of gas produced.

There are three primary means to reduce the amount of natural gas consumed or lost in the extraction and production process:

1. Reducing intentional flaring and venting,
2. Reducing unintentional leaks, and
3. Increasing the efficiency of engines, compressors, heaters and other processing facilities. Using electricity instead of natural gas could also fit in this category, but is discussed in the next section.

3.2 Using cleaner energy sources to extract and produce natural gas

Currently, raw natural gas is the primary fuel used to provide the energy needed at wells, pipelines and processing plants. In 2009, this fossil fuel consumption accounted for 59% of the emissions from the natural gas sector.[33] One way to reduce those emissions is to use cleaner sources of energy (e.g., electricity from renewable sources) in place of natural gas or other fossil fuels.

At wellheads and other remote locations, solar panels, wind turbines and other renewable technologies could be used to complement conventional energy sources. The technical feasibility of these solutions has been demonstrated in the Noel Major gas project (developed by BP and now owned by Apache), located in the Montney Basin. The project is currently using remote electrification to achieve a very small emission footprint at its well sites. The degree to which on-site renewable energy could replace natural gas combustion at compressors and processing stations is less clear because of the higher demands for energy within a confined area.

Another option is connecting B.C.'s gas sector to BC Hydro's electricity grid so that larger scale renewable energy projects would be able to meet the demands of processing plants and compressors. Although on-site, small-scale electrification is a relatively low-impact and non-controversial solution, the same cannot be said for large-scale projects. Electrification of large-scale projects would likely result in controversy because of the necessitated increased generation and transmission infrastructure that would be required and that would likely result in significant land and water impacts. Of note, integrating the Horn River basin with the BC Hydro grid would require a significant grid extension because Fort Nelson is not currently connected.

According to BC Hydro's load forecast, the electricity demands associated with Montney and Horn River Basins in 2020 (fiscal) are expected to be 2,101 and 1,061 gigawatt-hours

[33] Calculated from Table A15-20 from Part 3 of Environment Canada's National Inventory Report: 1990 to 2009 — United Nations Framework Convention on Climate Change (UNFCCC), "National Inventory Submissions 2011," Canada.

respectively.[34] For context, the combined 3,162 gigawatt-hours would be equivalent to six per cent of B.C.'s average firm generating capability. It is beyond the scope of BC Hydro's forecast to indicate how much self-generation from natural gas and direct combustion of natural gas would still be occurring in the sector.

The potential for these types of project-specific impacts highlights the need to take the time to understand the cumulative impacts that the gas sector would have under different development trajectories. Failing to do so could lock B.C. into a development trajectory where both problems and solutions come with unacceptable impacts.

3.3 Preventing emissions from reaching the atmosphere

Relative to the other emission sources in the sector, processing facilities for natural gas are by far the biggest. Vented carbon dioxide that is stripped from raw natural gas accounted for 32% of the sector's emissions in 2000.[35,36] As is discussed in Section 5.2, vented carbon dioxide is a particularly important concern for gas from the Horn River basin due to the high levels of formation carbon dioxide that need to be removed before the gas is marketable. In contrast, natural gas from the Montney Basin has much lower levels of formation carbon dioxide.

A potential solution to reduce a significant proportion of the vented carbon dioxide emissions is a technology called carbon capture and storage (CCS). Carbon capture and storage is a process that collects carbon dioxide emissions before they are dispersed into the atmosphere, compresses them and transports them by pipeline to sites where they can be injected into saline aquifers or salt caverns for storage. Spectra Energy (B.C.'s largest gas producer and GHG emitter[37]) has been testing the viability of a large-scale CCS project near Fort Nelson that, if deemed technically and economically feasible, could capture and store two million tonnes of vented emissions from their Fort Nelson gas processing plant annually.[38]

Carbon capture and storage has been in practice for decades at multiple small sour gas plants throughout the Western Canadian Sedimentary Basin. However, based on documents filed to B.C.'s Environmental Assessment office by Encana regarding their proposed Cabin gas processing plant (also near Fort Nelson), Encana has determined that large-scale CCS projects, such as the one being investigated by Spectra, are not currently possible due to technical and

[34] BC Hydro, *Electric Load Forecast 2010/11 – 2030/31*, Table A3.1, accessed March 2011, http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2011q1/electric_load_forecast.Par.0001.File.Electric-Load-Forecast-2010-march-24.pdf

[35] The data is based on 2000 figures, the most recent in the following study — The Canadian Association of Petroleum Producers (CAPP), "A national inventory of greenhouse gas (GHG), criteria air contaminant (CAC) and hydrogen sulphide (H2S) emissions by the upstream oil and gas industry," 2004

[36] More recent data in Environment Canada's National Inventory report does not disaggregate vented carbon dioxide emissions.

[37] Environment Canada, *Facility level greenhouse gas reporting database*, 2009, accessed August 23, 2011, http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=040E378D-1

[38] For more information see: Spectra Energy, *Carbon capture and storage*, http://www.spectraenergy.com/Responsibility/Climate-Change/Carbon-Capture-Storage/

commercial challenges.[39] For CCS to be feasible, companies such as Spectra and Encana will either need to be required by law to implement the technology or government policies like carbon taxes and cap-and-trade systems will be needed to make it cost-effective.

While carbon capture and storage could in theory be applied to any process that emits GHG emissions, its cost-effectiveness depends on having relatively concentrated streams of carbon dioxide and suitable geology to safely store the emissions. Natural gas processing facilities in northeastern B.C. seem to offer a good combination of these characteristics. Carbon dioxide already needs to be stripped from raw gas to make the gas a marketable product, resulting in a concentrated stream of carbon dioxide, unlike the GHG emissions from a coal-fired electricity plant, for example. In terms of geology, a 2004 report on the potential of applying CCS to gas processing plants in northeastern B.C. found the geology of the region to be potentially suitable for carbon dioxide storage.[40]

3.4 Limiting the amount of natural gas extracted and processed

The technological solutions described in the previous three sections all offer the potential to reduce GHG emissions from B.C.'s natural gas sector. It certainly seems possible that the province could produce more gas than is currently the case with fewer total emissions; however, even in the best-case scenario, the emissions per unit of natural gas produced cannot be reduced to zero. Therefore, if the GHG emissions from natural gas extraction, processing and transmission cannot be reduced enough to fit within a plan that results in the province meeting its climate change targets, the B.C. government should explore limits on the amount of natural gas that is produced in province.

As discussed in Section 2, the lack of a national or a continental climate plan is further motivation for B.C. to discuss potential limits to development. Recognizing that demand for natural gas will decline in the long-term, it would be appropriate for B.C. to consider how the province will adapt to that scenario.

Similar to the discussion about large-scale electrification options, the potential for a scenario in which sector growth overwhelms the capacity of technological solutions to curb emissions points to the need for the province to take the time to understand the overall development trajectory for the sector and think through if, and how, it may need to be constrained. Undertaking such planning in a proactive manner would allow the province to determine what limits to development (if any) are needed and how best to set them.

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[39] Encana's application for a B.C. environmental assessment certificate: Government of British Columbia, *Cabin gas plant project)*, Section 8, December 11, 2008, http://a100.gov.bc.ca/appsdata/epic/html/deploy/epic_document_341_30457.html

[40] S. Bachu, "Evaluation of CO_2 sequestration capacity in oil and gas reservoirs in the western Canada sedimentary basin," Alberta Geological Survey and Alberta Energy and Utilities Board, 2004, http://science.uwaterloo.ca/~mauriced/earth691-duss/CO2_General%20CO2%20Sequestration%20materilas/CO2_eval_ccs_westcanada_2004.pdf

4. Government production and emissions forecasts

British Columbia's Climate Action Plan includes two basic scenarios for production and greenhouse gas emissions from the natural gas sector. The first scenario is typically referred to as "business as usual" (BAU) and it is considered to be the worst-case scenario for emissions, where nothing is done to restrain them. The second scenario adjusts the BAU production and emissions trajectory in response to the policies in B.C.'s Climate Action Plan — some of which have already been implemented and others of which have been committed to. The Climate Action Plan continues to be the primary guiding document for B.C.'s efforts to reduce GHG emissions so it is worthwhile presenting it as a starting point for this analysis.

Figure 6 shows the gas production forecast, which is the same in both scenarios — a nine per cent increase over 2007 levels by 2020.[41] Figure 7 shows the GHG emissions forecasts for the gas sector in the two scenarios. In the BAU scenario, emissions are predicted to be five per cent below 2007 levels by 2020. In the Climate Action Plan scenario, emissions are predicted to be 37% below 2007 levels by 2020.[42] As discussed in Section 1, more recent analyses conducted for the B.C. government and BC Hydro suggest that natural gas production in the province will be higher than previously forecast.

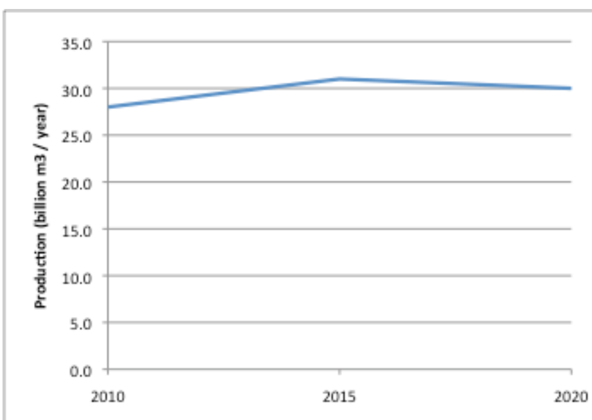

Figure 6 — Gas production forecast in B.C.'s Climate Action Plan

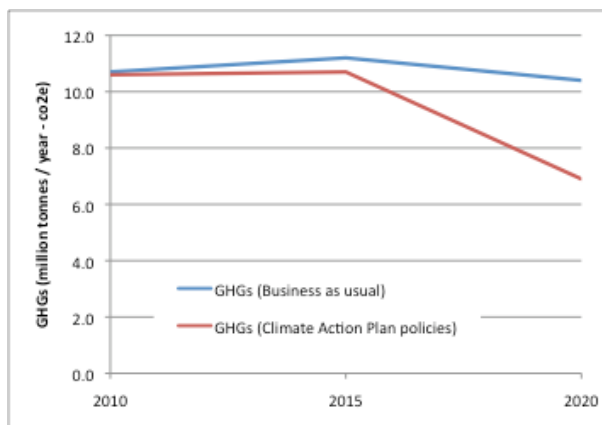

Figure 7 — GHG emissions forecasts for the natural gas sector from B.C.'s Climate Action Plan

[41] Government of British Columbia, *Climate action plan,* Appendix I, Table 2, 2008, http://www.livesmartbc.ca/attachments/climateaction_plan_web.pdf

[42] Ibid, Appendix I, Table 8 & 11

If the 37% reduction from the gas sector can be achieved it would make an important contribution to the province's efforts to cut emissions by 33% over the same time period. Based on the Climate Action Plan the main tool the province is relying on to achieve the reductions from the natural gas sector is a price on carbon that will make the technical solutions to reduce emissions more cost-effective relative to traditional approaches.

The province has implemented a carbon tax on fossil fuel combustion that currently applies a price on carbon of $25 per tonne of carbon dioxide equivalent on 66% of the emissions from the natural gas sector.[43] The carbon tax is scheduled to increase to $30 per tonne on July 1, 2012. While the carbon tax will help decrease emissions from the sector, it will not be sufficient to achieve the cuts envisioned in the Climate Action Plan based on the current tax rate schedule and coverage.

The emissions reductions from the natural gas sector in the Climate Action Plan are achieved because of a significantly higher carbon price anticipated for industrial emitters, including the natural gas sector ($100 per tonne in 2021).[44] The carbon price is also applied more broadly than the carbon tax, capturing the non-combustion industrial emissions currently exempted. In the Climate Action Plan that price is created by a cap-and-trade system (an alternative approach to carbon pricing). Figure 8 shows the carbon price schedules for the carbon tax (already legislated) and the cap-and-trade system (modeled for the Climate Action Plan, but not implemented). Although the reductions achieved in the Climate Action Plan rely on a cap-and-trade system they could just as easily be achieved with a carbon tax if the price schedule was comparable.

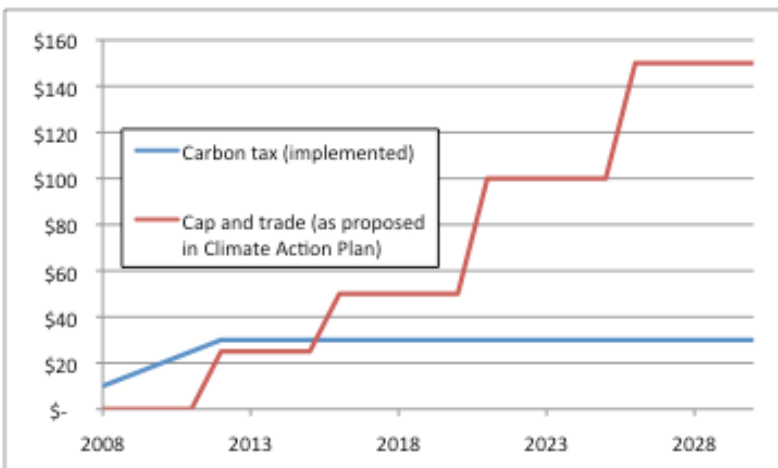

Figure 8 — Carbon prices (per tonne of carbon dioxide equivalent) generated by B.C.'s carbon tax (legislated) and proposed cap-and-trade system (anticipated)

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[43] The $25 per tonne is the carbon tax rate in effect from July 1, 2011 to June 30, 2012. The 66% is the sum of 59% from processing, pipelines, and extraction from Environment Canada's GHG inventory and seven per cent from flaring in the CAPP report.

[44] Government of British Columbia, *Climate Action Plan*, Appendix I, Table 10, 2008, http://www.livesmartbc.ca/attachments/climateaction_plan_web.pdf

B.C. has been designing a cap-and-trade system with partners from the Western Climate Initiative (WCI)[45] and is positioned to be able to launch the system in early 2012, if the government chooses to do so. Whether or not the cap-and-trade system that B.C. is proposing will create a price on carbon comparable to the Climate Action Plan will depend on the province's cap-and-trade regulations, which have yet to be announced.[46] Economic modeling completed for the WCI's cap-and-trade system estimated that the carbon price will reach US$33 per tonne in 2020. Based on that assessment it seems unlikely that its cap-and-trade system will be capable of generating a price on carbon as high as anticipated in B.C.'s Climate Action Plan. If the system is implemented B.C. will likely need to explore additional approaches to generate an effective price closer to $100 per tonne.

[45] The WCI is a collaboration of eleven states and provinces working together to identify, evaluate, and implement policies to tackle climate change at a regional level. One of the policies is a cap-and-trade system that California, B.C., Quebec, Ontario and Manitoba are designing. California, B.C. and Quebec are planning to implement the system starting at the beginning of 2012, although California and Quebec have announced that 2012 will not have an enforced cap. Ontario has said it will join in 2013.

[46] For more details on B.C.'s intended cap-and-trade regulations, see the Pembina Institute's comments submitted as part of a cap-and-trade consultation from the end of 2010: M. Horne, "Recommendations for British Columbia's proposed cap-and-trade regulations," December 8, 2010, http://www.pembina.org/pub/2132

5. Updating the Climate Action Plan to Reflect New Realities

The business as usual and Climate Action Plan scenarios discussed in the previous section likely understate future emissions from British Columbia's gas sector for two reasons:

1. The level of natural gas production is now forecast to be higher than estimated in the Climate Action Plan; all else being equal, greenhouse gas emissions will be higher. The underestimate occurred because the relatively low-cost ability to extract shale gas resources, which are now expected to dominate B.C.'s gas sector, was not then understood.
2. Shale gas from the Horn River basin has much higher levels of formation carbon dioxide than conventional gas production in B.C. That formation carbon dioxide needs to be removed from raw natural gas so — barring any technologies to capture and store the emissions — the same amount of gas production will produce more emissions.

5.1 Accounting for higher production forecasts

The Climate Action Plan underestimates the potential levels of gas production and, therefore, the associated GHG emissions. The Climate Action Plan's projected increase in production of 28 to 30 billion cubic metres between 2010 and 2020 does not account for two major gas processing plants, which have since been proposed in the province:

1. Spectra Energy's proposed Fort Nelson expansion would reactivate unused capacity in the existing Fort Nelson plant and add an additional plant north of Fort Nelson. The combined processing capacity of these plants would be 12.9 billion cubic metres by 2012 — an increase of 7.8 billion cubic meters relative to 2009.[47]
2. Encana has received approval to build its own processing facility at Cabin Lake, in northeastern B.C.[48,49] At its proposed date for full operation (2015), the Encana Cabin Gas Plant would process up to 8.2 billion cubic metres of natural gas annually.[50]

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[47] Spectra Energy, *Fort Nelson North Processing*, http://www.spectraenergy.com/Operations/New-Projects/Fort-Nelson-North-Processing/

[48] Government of British Columbia, "Cabin gas plant project approved," media release, January 28, 2010, http://www2.news.gov.bc.ca/news_releases_2009-2013/2010ENV0004-000105.htm

[49] B.C. environmental assessment certificate can be found here: Government of British Columbia, *Cabin gas plant* project, EA certificate documentation, http://a100.gov.bc.ca/appsdata/epic/html/deploy/epic_document_341_31937.html

Combined, these expansions will require an additional 16 billion cubic metres of gas per year of production to operate at design capacity. In 2020, that would represent a 62% increase above 2007 levels of production assuming they operate at 90% capacity — compared to the nine per cent increase forecasted in the Climate Action Plan. The significance of these two gas-processing expansions is shown in Figure 9. Because production is being underestimated, the GHG emissions projected in the province's Climate Action Plan are also currently underestimated. See Appendix 3 for the impact of accounting for higher production forecasts on the sector's GHG emissions independent of other factors.

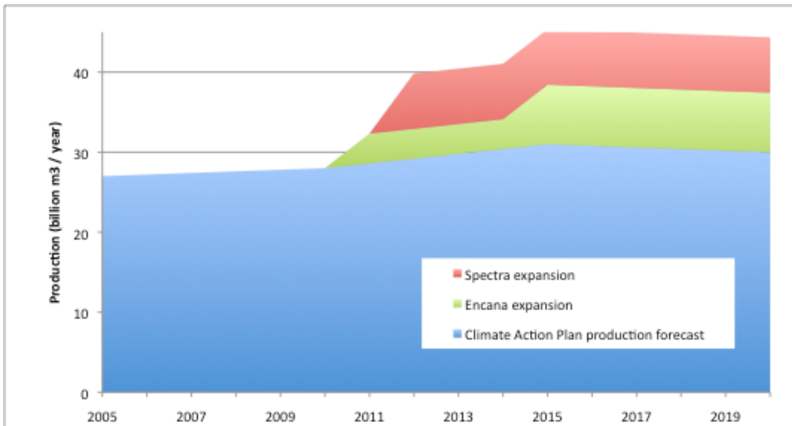

Figure 9 — Implications of proposed Encana and Spectra gas processing expansions on gas production

A report completed for the provincial government reviewing the Climate Action Plan cites similar reasons for greater than anticipated growth in the sector.[51] That analysis estimates a slightly higher (63%) increase in production above 2007 levels to 48.3 billion cubic metres by 2020. BC Hydro's 2010 load forecast includes an even higher projection, with forecast production of 54.7 billion cubic meters in 2020 (fiscal), with 32.4 billion cubic metres coming from Montney and 22.3 billion cubic metres coming from Horn River.[52]

For the purposes of this report, we have relied on the more conservative forecast that only includes approved expansions in gas processing capacity. In either case the general conclusion is that natural gas production and the associated GHG emissions are now expected to be much higher than anticipated when the Climate Action Plan was prepared. The same can be said for the challenge involved in reducing those emissions.

There is one other potential implication of increased production that could push emissions in B.C.

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[50] Encana's application for a B.C. environmental assessment certificate: Government of British Columbia, *Cabin gas plant project)*, Section 3, December 11, 2008, http://a100.gov.bc.ca/appsdata/epic/html/deploy/epic_document_341_30457.html

[51] M.K. Jaccard and Associates Inc., "Sensitivity and uncertainty analyses to inform British Columbia's interim greenhouse gas targets," Climate Action Secretariat, 2008, http://www.livesmartbc.ca/attachments/MKJA_Sensitivity_Report.pdf

[52] BC Hydro, *Electric Load Forecast 2010/11 – 2030/31*, Table A3.1, accessed March 29, 2011, http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2011q1/electric_load_forecast.Par.0001.File.Electric-Load-Forecast-2010-march-24.pdf

higher. Associated with increased production are proposals to export liquefied natural gas by tanker from Kitimat.[53] These types of projects would require additional energy to liquefy the natural gas compared to current pipeline compression requirements. Whatever fossil fuels are used to meet the increased energy demands would add to the GHG emissions from the gas sector compared to historical production. This factor has not been assessed in detail, but research from Jaramillo, Griffin and Matthews (2007) found that electricity generated from liquefied natural gas in a combined cycle plant increased the life cycle GHG emissions by 33% relative to domestic natural gas not requiring liquefaction.[54] The life cycle emissions from liquefied natural gas would be 37% less than the life cycle emissions from a new coal plant. Any actual emissions from a liquefied natural gas plant in Kitimat would depend on the mix of natural gas and electricity used for compression energy.

5.2 Accounting for more emissions intensive shale gas

As discussed, one of the major sources of emissions from the natural gas sector are gas-processing plants where raw gas has impurities such as carbon dioxide and hydrogen sulphide removed. The carbon dioxide that is stripped from raw natural gas (referred to as formation carbon dioxide) is currently vented to the atmosphere. Based on a Jaccard and Griffin (2010) study, gas historically produced in B.C. has been comprised of between two and four per cent carbon dioxide before processing.[55] Natural gas from the Horn River Basin is 12% carbon dioxide, while the gas from the Montney Basin has a carbon dioxide content of one per cent.[56]

Based on 2020 gas production forecasts from the BC Hydro 2010 load forecast, gas from the Montney basin will account for 59% of B.C.'s production and gas from the Horn River basin will account for 41%.[57] The Canadian Association of Petroleum Producers provides a similar forecast in terms of total production and proportional shares: 54% from the Montney basin and 46% from the Horn River basin.[58] The BC Hydro projections are used for the remainder of this analysis.

The net effect of these shifts would mean that the GHG emissions per unit of gas extracted and produced in B.C. would be 16% higher than historical levels where the vast majority of B.C.'s gas production came from conventional sources. The combined 16% obscures the very different pictures in the Horn River Basin and Montney Basin. If 100% of B.C.'s gas production came from the Horn River the increase would be 86% because of the extremely high levels of formation

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[53] For example, Kitimat LNG is one proposed project with investment from Apache Corporation, EOG Resources Inc., and Encana Corporation. See kitimatlngfacility.com/index.aspx.

[54] P. Jaramillo *et al.*, "Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation," Environmental Science and Technology, p. 6290–6, 41(17), 2007

[55] M. Jaccard & B. Griffin, "Shale gas and climate targets: Can they be reconciled?" *Pacific Institute for Climate Solutions,* 2010

[56] National Energy Board, "A primer for understanding Canadian shale gas," 2007, http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009-eng.pdf

[57] BC Hydro, *Electric Load Forecast 2010/11 – 2030/31*, Table A3.1, accessed March 2011, http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2011q1/electric_load_forecast.Par.0001.File.Electric-Load-Forecast-2010-march-24.pdf

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

carbon dioxide. However, if 100% of B.C.'s gas production came from the Montney Basin emissions would actually decrease by 22% relative to conventional production because of low levels of formation carbon dioxide.

Because the increasing average carbon dioxide content of B.C.'s gas is not being accounted for the GHG emissions projected in the province's Climate Action Plan will also be underestimated. See Appendix 3 for the impact of accounting for the shift to shale gas, independent of other factors, on the sector's GHG emissions.

There are several other potential implications of the shift to shale gas that could push emissions even higher. The first relates to the concern that more methane may be released from shale gas wells than conventional gas wells; natural gas is 70 to 90% methane, which is a powerful greenhouse gas. Recent analysis from Howarth (2011) and the U.S. Environmental Protection Agency (2010) conclude that the emissions from well completion in U.S. shale gas wells are much higher than conventional gas wells. The Howarth study found those well completion emissions to be 190 times higher in shale gas wells compared to conventional wells.[59] The U.S. Environmental Protection Agency estimated the difference at 249 times.[60] Both studies admit a lack of high quality data in reaching their conclusions.

These numbers are not directly applicable in B.C. because they assume methane is vented, but this is not allowed in B.C. unless the gas heating value, volume or flow rate is insufficient to support stable combustion.[61] The actual percentage of wells in which venting would be permissible is not known, so the increase in emissions, if any, is also unknown. If the factor of 190 found in the Howarth study applied in B.C. the net effect would be GHG emissions from the natural gas sector being 19% higher.[62] The actual increase is likely much lower and, due to an inability to produce an accurate estimate, the potential that shale gas wells emit more methane than conventional wells has not been accounted for in the results presented in the next section.

Further research into the issue in a B.C. context should be a priority. In particular, it would be useful to understand the volumes of methane produced from B.C. shale gas formations as well as the proportions of that methane that are captured for use, flared and vented.

Two other climate change concerns about a shift to shale gas exist:

1. Energy is needed to transport and inject the large volumes of water needed in the hydraulic fracturing process.

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[59] R. Howarth *et al.,* "Methane and the greenhouse-gas footprint of natural gas from shale formations," Climatic Change, p. 679–690, 106, 2011

[60] United States Environmental Protection Agency (USEPA), "Greenhouse gas emissions reporting from the petroleum and natural gas industry: Background technical support document," Table 1, 2010

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

[62] The 19% result was calculated using the 'low' estimates from the Howarth paper, which estimated total methane emissions from shale gas production to be 2.1 times higher than conventional production. The 2.1 times factor is much lower than the 190 times factor because there are other sources of methane emissions from natural gas production (e.g. leaks from pipelines) that do not change between conventional and shale gas production. The 2.2 times factor is further scaled down to the 19% result because methane emissions were only 17% of the GHG emissions from B.C.'s natural gas sector in 2008.

2. Energy is needed to compress and transport the larger volumes of carbon dioxide that will be present in B.C.'s average mix of raw gas compared to current production.

In both cases whatever fossil fuels are used to meet the increased energy demands would add to the GHG emissions from the gas sector compared to historical production. Neither of these factors has been included in the calculations because reliable estimates of their impacts were not available. Further study to understand the magnitude of these concerns is merited.

5.3 Implications of higher, and more greenhouse gas intensive, production

The implications of natural gas production being higher and more GHG intensive than forecast in the Climate Action Plan are shown in Figure 10 and Figure 11. With both factors accounted for the GHG emissions from the gas sector would be 15% above 2007 levels in 2020 with all of the policies promised in the Climate Action Plan (the solid line in Figure 11). That compares to 37% below 2007 levels stated in the B.C. Climate Action Plan with lower and less GHG intensive forecasts (the solid line in Figure 10). The numeric results are presented in Table 1.

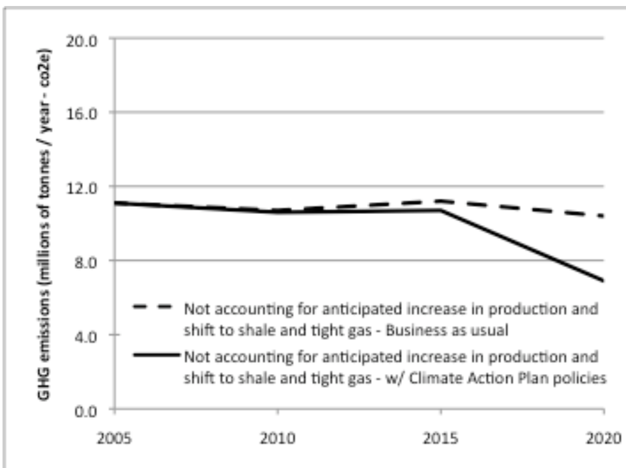

Figure 10 — Greenhouse gas emission forecasts without accounting for increased production and shift to shale gas

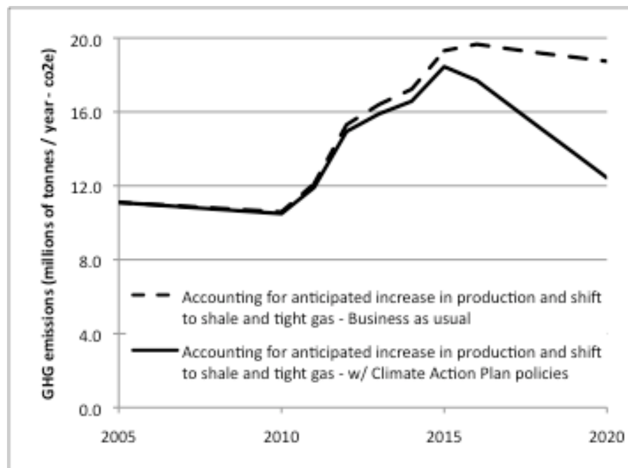

Figure 11 — Greenhouse gas emission forecasts after accounting for increased production and shift to shale gas

Table 1 — Greenhouse gas emission implications of underestimating production and shift to shale gas

	Projected 2020 emissions relative to 2007 with policies from:	
	Business as usual scenario	Climate Action Plan scenario
Not accounting for anticipated increase in production and shift to shale gas (as in B.C.'s Climate Action Plan)	5% below	37% below
Accounting for anticipated increase in production and shift to shale gas	72% above	15% above

Instead of a sector-wide reduction that would have been slightly ahead of the province-wide reduction target of 33% the gas sector is left with emissions that are slightly above 2007 levels. That is not to say that the policies in the Climate Action Plan would not have an impact; without them the increased production and shift to shale gas would leave emissions from the sector 72% above 2007 levels in 2020. The decline in emissions from 2015 to 2020 also offers a positive story: sharp cuts in the sector's emissions are possible with strong policies.

The GHG reductions anticipated with the Climate Action Plan policies in Figure 11 assume the same percentage reductions can be achieved relative to the business as usual scenario. This approach is limited in that it does not account for the likelihood that the costs of GHG mitigation options are likely to be different than the scenario shown in Figure 10. For example, the shift to newer production that would accompany increased production could present more low cost opportunities than initially assumed, which could lead to greater percentage reductions.

Higher than anticipated GHG emissions from the natural gas sector means that it will be more challenging for B.C. to achieve its legislated GHG reduction targets. As shown in Figure 12 the Climate Action Plan estimated that the plan's policies would be sufficient to reduce provincial emissions to 19% below 2007 levels by 2020 (the solid black line). If the emissions from the gas sector are revised to account for increased production and the shift to shale gas then the Climate Action Plan policies are only sufficient to reduce provincial emissions to 10% below 2007 levels by 2020 (the long-dashed red line). The provincial target of 33% below 2007 levels is also shown (the short-dashed green line).

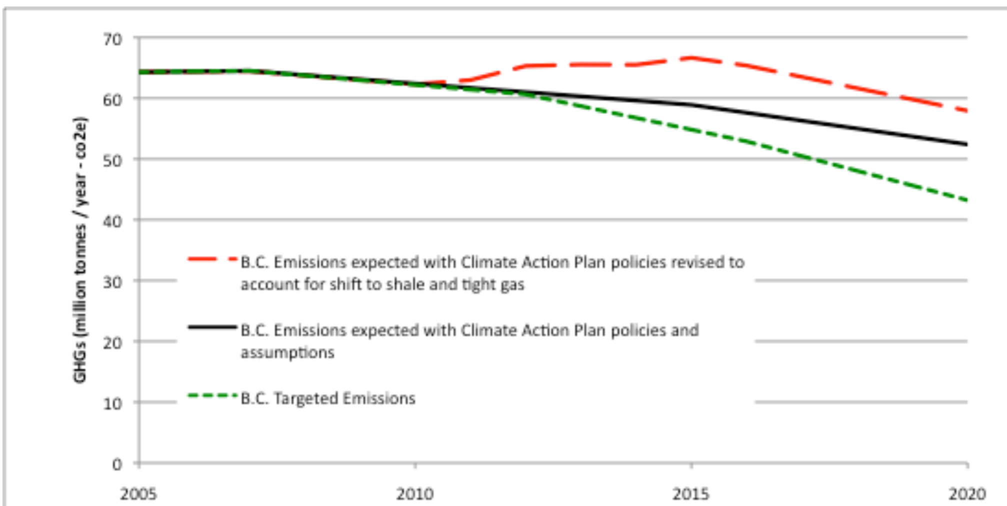

Figure 12 — Provincial greenhouse gas forecasts and targets

While the province's Climate Action Plan acknowledges that there is a gap between the plan and the province's target, unaccounted for factors in the natural gas sector exacerbate that gap. Shrinking — and eventually eliminating — the gap will require all of the proposals in the Climate Action Plan to be fully implemented and a number of additional steps to be taken. In summary, the results make it clear that stronger policies than promised in the Climate Action Plan will be needed for the natural gas sector to make an adequate contribution to the province's efforts to reduce GHG emissions.

6. Recommendations

The previous sections have raised a number of concerns relating to greenhouse gas emissions from shale gas activity anticipated in British Columbia over the next decade. In order to ensure that B.C. understands and manages the water and climate risks responsibly, the Pembina Institute offers the following eight recommendations for the B.C. government.

1. Update and complete the Climate Action Plan for the province to indicate how B.C. will achieve its 2012, 2016 and 2020 greenhouse gas emission reduction targets. For targets to be meaningful, governments need plans and policies that give a credible chance of achieving the targets.

2. Develop greenhouse gas management plans for current proposed shale gas development in the Montney and Horn River basins. The plans should articulate a pace and scale of development that limits the sector's greenhouse gas emissions such that province is in a position to achieve its greenhouse gas emission reduction targets with strong policies in other sectors too. It is likely that the plan would slow proposed increases in development relative to current business as usual projections. Part of the discussion leading up to the plan could explore focusing new development in the Montney basin where levels of formation carbon dioxide are much lower. The plans should:
    - Require approvals of major projects (such as natural gas processing plants) to be consistent with the limits on greenhouse gas emissions.
    - Require frequent monitoring and public reporting of cumulative impacts to ensure that local communities and the general public, First Nations, governments, industry and non-governmental organizations have a complete picture on the impacts that are occurring. Some of this data is already collected by various agencies (e.g., Ministry of Environment's large emitters inventory), but it is not available in a single location and there are some gaps.
    - Integrate with other cumulative effects of concern such as water use and disposal. In combination these effects of concern could be managed collectively in a larger cumulative effects management system.

3. Broaden the application of carbon pricing in British Columbia to include the non-combustion sources of emissions that can be accurately measured and are not currently covered by the carbon tax. This is particularly relevant for vented natural gas and vented formation carbon dioxide in the natural gas sector, because they are not currently covered by the carbon tax and can be accurately measured. The broadened carbon price could be applied either through cap-and-trade and/or the carbon tax.

4. Continue increasing the carbon price applied in British Columbia such that it is in line with levels adequate for the province to meet its greenhouse gas reduction targets. As discussed, the province's Climate Action Plan includes a carbon price of $100 per tonne by 2020, and

that plan gets almost 75% of the way to B.C.'s target (before accounting for the upward pressure on GHG emissions from the natural gas sector discussed in this report). A national modelling study by M.K. Jaccard and Associates Inc., completed for the Pembina Institute and David Suzuki Foundation, found the 2020 price will need to approach $200 per tonne for Canada to reduce emissions to 25% below 1990 levels by 2020.[63, 64] Based on those two studies, the 2020 price needed in B.C. is likely between $100 and $200 per tonne. The carbon price could be achieved either through raising the carbon tax and/or implementing a cap-and-trade system.

5. Encourage partner jurisdictions to implement carbon-pricing systems and other strong climate policies that follow the lead of, and build upon, B.C.'s carbon tax. The greater the number of jurisdictions taking action on climate change, the better the environmental and economic outcomes will be. B.C. can play an important role in helping other jurisdictions to take action by sharing its experiences with the carbon tax.

6. Require new gas processing plants that strip significant volumes of carbon dioxide from raw gas to capture and permanently store that carbon dioxide if plant proponents do not do so as a result of a carbon price. This is particularly important for gas processed from the Horn River that has high levels of formation carbon dioxide relative to conventional gas production in B.C. and other shale gas reserves. If new plants are built without carbon capture and storage technology, it will be more difficult and more expensive to retrofit them at a later date. A carbon price in the range discussed in the previous recommendation would likely be adequate to justify the costs of investing in carbon capture and storage technologies, so it is only in the absence of that price that a technology specific regulation would be warranted.

7. Assess the anticipated greenhouse gas emissions associated with well completion in the Horn River and Montney Basins in order to understand their relevance to overall greenhouse gas emissions from natural gas production in B.C. There is an emerging body of research looking into these questions that B.C. could coordinate with, but limited B.C. specific research to date.

8. Assess the opportunities for clean electricity to replace fossil fuel use as a greenhouse gas reduction strategy, including opportunities for electrification in the natural gas sector. This assessment would help answer questions about whether or not enabling fossil fuel extraction is a valuable enough use of electricity given the social, economic, and environmental impacts associated with generation. It would also provide an opportunity to test the opportunity cost of using electricity in the natural gas sector, where the same unit of electricity could also be used to meet other demands in B.C., or to help other jurisdictions reduce their reliance on fossil-fuel electricity.

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[63] The Pembina Institute and David Suzuki Foundation, "Climate leadership, economic prosperity, 2009, http://www.pembina.org/pub/1909

[64] B.C.'s target relative to 1990 is 12% below by 2020.

Appendix 1

The sources of emissions in British Columbia's natural gas sector are shown in Table 2 below.

Table 2 — Sources of emissions in British Columbia's natural gas sector

Source	Combustion	Non-Combustion
Burning fossil fuels, predominantly diesel, to run the trucks and pumps needed to access the wells, transport water and conduct hydraulic fracturing.	✓	
Burning natural gas directly from natural gas wells (flaring) for a variety of purposes such as testing a well's viability (when in-line testing is not possible), burning off waste products (also done at processing plants), enabling well maintenance and controlling pressure.	✓	
Venting natural gas when purging gas pipelines, processing facilities or tanks		✓
Burning natural gas and using fossil fuel powered electricity to operate instruments and controls at well sites and processing facilities.	✓	
Venting methane from glycol dehydrators, which are used to remove water from natural gas.		✓
Unintentionally allowing leaks of natural gas (methane) from incompletely sealed connections at pipelines and processing plants, leaking well-site casing and uncontrolled tanks.		✓
Burning natural gas and using fossil fuel powered electricity to power the compressors that allow the natural gas pipeline network to operate.	✓	
Burning natural gas and using fossil fuel powered electricity to power the processing plants that strip impurities such as hydrogen sulphide and carbon dioxide from raw natural gas.	✓	
Venting the carbon dioxide that is stripped from raw natural gas in gas processing plants (known as formation carbon dioxide) to convert the gas to a marketable product.		✓
Burning natural gas for end uses such as heating, transportation, electricity generation or industrial processes.	✓	

Appendix 2

Table 3 indicates how the figures in Environment Canada's greenhouse gas inventory were translated into those shown in Table 3.

Table 3 — Converting Environment Canada's inventory categories to B.C. gas sector

Environment Canada category	Percentage of Environment Canada emissions estimated to be from B.C.'s gas sector	Rationale
Fossil fuel production and refining	90%	Subtracted the 2008 reported emissions from the Burnaby and Prince George petroleum refineries to focus on the gas sector. The resulting 90% was applied to all years.
Mining and oil and gas extraction	50%	Assumption — The implications of this assumption are not significant, because the total emissions from this category are approximately 10% of the gas sector's total.
Pipelines	100%	Based on the following statement on page 55 of Canada's National Inventory report, 1990 to 2009: "The pipeline emissions included in the Other Transportation subsector are combustion emissions primarily from natural gas transport.
Fugitive Sources – Oil and Natural Gas	100%	Not aware of any other sources that would be included in this category.

Appendix 3

Underestimated production forecasts

If underestimated production was the only factor unaccounted for in forecasts for British Columbia's gas sector, it would influence emissions projections as shown in Table 4. So instead of a 37% reduction in 2020 relative to 2007, the Climate Action Plan policies would reduce emissions by 14% when increased production is accounted for.

Table 4 — Greenhouse gas emission implications of underestimating gas production

	Projected 2020 emissions relative to 2007 with policies from:	
	Business as usual scenario	Climate Action Plan scenario
Not accounting for proposed Spectra and Encana processing expansions (as in B.C.'s Climate Action Plan)	5% below	37% below
Accounting for proposed Spectra and Encana processing expansions	30% above	14% below

Not accounting for the shift to shale gas

If the shift to shale gas was the only factor unaccounted for in forecasts for B.C.'s gas sector, it would influence emissions projections as shown in Table 5. So instead of a 37% reduction in 2020 relative to 2007, the Climate Action Plan policies would reduce emissions by 24% when increased production is accounted for.

Table 5 — Greenhouse gas emission implications of underestimating carbon dioxide content

	Projected 2020 emissions relative to 2007 with policies from:	
	Business as usual scenario	Climate Action Plan scenario
Not accounting for anticipated shift to shale gas (as in B.C.'s Climate Action Plan)	5% below	37% below
Accounting for anticipated shift to shale gas	14% above	24% below