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Foreword

This is the second in a series of papers being undertaken by the Fraser Institute in the course of developing a Continental Energy Strategy. As noted in *A Vision for a Continental Energy Strategy*, published by the Fraser Institute in 2008, the fundamental objective of this strategy is to ensure that the applicable policy and institutional frameworks are conducive to as rapid a development of North America's energy resources as possible in light of market conditions, legitimate environmental concerns, and global investment opportunities (Klein and Tobin, 2008). Market driven development of natural gas and other energy resources is predicated on the economic benefits that such development can bring through expanded employment and improvements in living standards, as well as improved security of energy supply.

Executive summary

This paper focuses on natural gas, an important element in North America's overall energy mix. A range of exploration, development, production, and transportation activities comprise the gas industry, which constitutes a significant component of the continental economy.

North America has approximately 323 trillion cubic feet (Tcf) of proved natural gas reserves, which is that portion of the continent's gas resources in discovered reservoirs deemed to be recoverable under current and anticipated economic conditions. These reserves represent about 5% of world gas reserves and approximately 11 years of the continent's gas requirements at 2009 gas consumption levels. Considering the extent of already discovered but unproved gas resources, and probable undiscovered resources, North America's gas supplies could be sufficient to meet the combined requirements of Canada, the United States, and Mexico for 100 years or more if non-market obstacles to their development and to the construction of pipeline transportation and storage facilities are removed.

Of the three North American countries only Canada is a net exporter of natural gas. Canada's natural gas exports have been decreasing because of declining production in the Western Canada Sedimentary Basin (WCSB). Production could be increased from unconventional sources, especially from shale formations in northeast British Columbia but also in Alberta and Eastern Canada, as well as from the Mackenzie Delta and offshore frontiers. Production increases could allow Canada to maintain net gas exports at about the expected 2010 level of 2 Tcf in spite of the projected growth in gas requirements associated with expanded oil sands bitumen production and increased demand from new gas-fired electric generation facilities. This assumes, however, that barriers to investment in the development of production from new gas supply sources, and in new transportation facilities, are eliminated or reduced.

In the United States, the growth in gas production from shale formations during the past several years, together with fairly modest growth in gas demand, has transformed the outlook for the country. While not long ago the U.S. was seen as becoming increasingly dependent on imports of liquefied natural gas (LNG), the shortfall in domestic gas production relative to total gas consumption requirements is now shrinking. In part, this is also a consequence of weaker US industrial sector gas demand due to the relocation of some energy-intensive businesses to overseas locations and the slower growth of gas-fired electric generation capacity because of government support for renewable energy projects.

The growth in US natural gas production from new sources of supply is likely to increase the competition that Canadian gas suppliers face in the US market. In response, Canadian producers are already seeking out overseas markets for LNG exports from British Columbia, while Canadian and US LNG import projects are largely being shelved.

In Mexico, the demand for natural gas is projected to increase much more rapidly than in either Canada or the United States during the next 20 years. This is mainly because of strong growth in gas requirements for electricity generation in Mexico. At the same time, however, growth in Mexican gas production is projected to continue to flag because of the inability to attract foreign investment. As a consequence, projections by the US Energy Information Administration suggest that Mexican gas imports could increase from about 0.6 Tcf in 2010 to 2.50 Tcf in 2030.

The analysis presented in this paper indicates that North America as a whole is likely to become more dependent on gas imports from overseas during the next 2 decades because of the outlook for gas demand and supply in Mexico. This suggests that growth of North American natural gas production beyond the volumes included in the forecasts would be readily absorbed into the continental market, provided that the incremental production is competitive with LNG imports. Further, as exhibited by foreign interest in the LNG export project in Kitimat, British Columbia, there are likely opportunities for Canadian gas sales to overseas markets. There is, therefore, an opportunity for firms to increase gas production here with ensuing employment and income benefits. However, for this to occur, unnecessary market barriers to investment in natural gas production and transportation facilities must be removed.

Barriers to investment in the expansion of North America's natural gas production capacity include, in some cases (e.g., Canada's Northwest Territories, California, and Colorado), royalties that are not competitive with other jurisdictions, including Texas and Australia. Also, some royalty schemes fail to recognize the higher costs involved in gas production from unconventional sources, such as shale and tight sand formations, where wells are often deeper than with conventional gas recovery, and production technologies more complex. Another obstacle to production growth is the moratoria on exploration drilling in the US Atlantic and Pacific offshore areas as well as in British Columbia's Queen Charlotte Sound. Additional barriers to investment include unnecessary delays to the obtaining of drilling and construction permits that frequently occur because of protracted regulatory procedures and processes, including time requirements for environmental impact assessments, native land claims, and disputes with land owners regarding compensation for land access.

Continuing uncertainty surrounding the extent and timing of emerging environmental policies related to greenhouse gas emissions prevents investors from knowing the full costs they could face. Moreover, environmental policy uncertainty impedes major investment in natural-gas-fired electric generation, where much of the incremental growth of gas demand is anticipated to occur, because investors don't know how competitive their cost structures will be compared with other electric power sources, especially coal-fired generation capacity.

In Mexico, the constitution largely prevents the multinational petroleum companies from participating in the exploration and development of oil and gas resources. Because ownership of hydrocarbons such as natural gas is vested with state-owned Petroleos Mexicanos (PEMEX), the multinationals are effectively limited to serving as subcontractors. Acting in this capacity is generally of little interest given the opportunities that they have to actively participate in the discovery and development of natural gas resources in other jurisdictions.

This study recommends that policy makers in Canada, the United States, and Mexico eliminate, or at least reduce, the barriers to investment in North American natural gas exploration and development, as well as in gas transportation and storage facilities, by

- Ensuring that natural gas royalty regimes throughout North America are globally competitive;
- Reflecting the higher costs of producing gas from unconventional, offshore, and frontier sources preferably through a universal net revenue tax, as recommended in an earlier Fraser Institute study (Clemens et al., 2008), and if that is not achievable, in natural gas royalty formulas;
- Abandoning the practice of modifying natural gas royalty schemes via ad-hoc, temporary special adjustments and incentives (which in fact underscore the fact that a royalty framework is badly in need of reform), and focusing on implementing simpler, straightforward royalty frameworks (unless the net revenue taxation approach is achievable);
- Reducing uncertainties surrounding environmental policy changes pertaining to natural gas production, processing, and transportation;
- Removing barriers to offshore natural gas exploration if it is determined that the environmental risks can be addressed satisfactorily;
- Streamlining regulatory processes related to the approval of natural gas production and pipeline construction permits ;
- Developing more efficient yet fairer procedures for resolving native land claims;
- Defusing and preventing disputes, actual and potential, over the terms and conditions of access to land by petroleum operators for exploration, development, and production.

- Requiring that the results of recently negotiated land access settlements be made publicly available, especially in regions where land access disputes arise frequently or tend to be prolonged.

In addition, innovative means must be sought to overcome the constraint that the Mexican Constitution, by vesting ownership of discovered natural gas and oil resources in state-owned Petroleos Mexicanos (PEMEX), imposes on the exploration and development of that country's natural gas resources.

These recommendations will be reviewed and developed further, as appropriate, in the process of determining a comprehensive energy strategy for North America.

About the Continental Energy Strategy initiative

As noted in the Institute's 2008 *Vision for a Continental Energy Strategy*, the proposed strategy will comprise a set of policy recommendations that are designed to ensure that North America's energy resources are developed as efficiently as possible given market requirements, science-based environmental concerns, and international competition (Klein and Tobin, 2008).

The primary objective of the energy strategy initiative is to ensure that the citizens of Mexico, the United States, and Canada are able to realize the maximum possible economic and social benefits from development of the continent's energy resource endowment through free and open markets, including free energy trade with the rest of the world. Increased development and production of the continent's energy resources would bolster the security of energy supply by, for example, increasing natural gas supply options. Certainly, accelerated investment in the development of Canada's energy resources that takes advantage of export opportunities holds considerable promise as it would trigger increased employment and income and help improve the quality of life for all Canadians.

Market forces will determine the most efficient allocation of North America's energy resources. For this reason, development of a continental energy strategy does not involve identifying energy investment, production, and trade targets. Rather, the focus is on ensuring that government policies pertaining to energy resource investment, development, consumption, and trade are stable, fair, and appropriate. Government must avoid intervening in energy investment decisions because the allocation of resources is best left to those who are motivated by market forces, have an in-depth knowledge of the technologies involved, and are prepared to take risks based on their understanding of how energy requirements are likely to change.

Public policy settings and institutional arrangements need to be conducive (by fostering conditions which allow free markets to function effectively) to investment in the expansion of the continent's energy supply capacity. In relation to a particular energy commodity, such as natural gas, this strategy requires identifying both barriers to such investment and prospective policy improvements, including the streamlining of regulatory procedures and processes. Policy frameworks must also support energy market competition and innovation, and allow investors freedom of choice to determine production locations and to define the scope of their businesses in accordance with market conditions.

Introduction

This paper is the second in a series of research projects that were initiated when the Fraser Institute launched the Continental Energy Strategy research program in 2007. As noted in the first paper in this series, *Towards North American Energy Security: Removing Barriers to Oil Industry Development*, the continental energy strategy will, for the most part, be focused on prospective policy changes that would allow the continent's energy markets to function more efficiently and provide greater opportunities for energy commodity trade among Canada, the United States, and Mexico (Angevine, 2010).

The focus of this paper is on natural gas, which is an important component of the North American energy use mix. According to the US Energy Information Administration, natural gas accounted for 24% of the continent's total primary energy demand in 2007.[1] This compared with oil's 40% share of total energy use, coal's 20% share, and nuclear power at 9% (Energy Information Administration, 2010d, table A2).

In the United States alone, a recent study prepared for America's Natural Gas Alliance indicates that employment in the natural gas industry combined with employment that this industry generated elsewhere in the economy accounted for 2,828,000 jobs in 2008—equivalent to 2.1% of total US employment. Moreover, the gas industry added $385 billion to the value of output in the US economy—equivalent to 2.7% of total gross domestic product (GDP) (IHS Global Insight, 2009a). A parallel analysis by the same organization found that the Canadian natural gas industry supported nearly 599,000 jobs or 3.5% of total employment in 2008. Further, the gas industry contributed $106.6 billion to Canada's GDP, representing 6.7% of total output (IHS Global Insight, 2009b).

Clearly, the natural gas industry is a major contributor to the economic well being of North Americans. However, if the capacity to produce natural gas were increased significantly from current levels, economic benefits from incremental employment, labor income, and GDP growth would result. Those benefits would come from the construction of the additional production, processing, and pipeline facilities, as well as from ongoing operations once the added facilities were in place.[2]

1 Primary energy is energy in its initial form, before it is transformed to another type of energy, such as electricity that is generated from oil, natural gas, or coal combustion.

2 This assumes that there is some underuse of the capital and labor needed to expand the natural gas industry such that the envisaged benefits are not offset by a general rise in inflation that reduces the capacity of other industries to compete in domestic and foreign markets and lowers real incomes.

The main purpose of this paper is, therefore, to identify those policies that will ensure that investment in the further development of North America's natural gas resources (encompassing exploration, production, processing, and transportation) is not constrained by unnecessary barriers. This assumes that government's role is limited to ensuring that the legal and institutional frameworks pertaining to the gas industry are fair and competitive with those in other industries and jurisdictions, and that policy changes in no way impinge upon free and open natural gas trade.

The paper begins by presenting necessary background for the recommendations that are developed, including overviews of North America's natural gas resource endowment, recent historical gas price patterns, and the continental natural gas supply and demand outlook. It then examines the uncertainties and risks that constrain the development of natural gas production and transportation facilities, and identifies barriers to such investment. Finally, it puts forward a number of policy initiatives for consideration as important elements of a continental energy strategy.

Natural gas reserves and resources

Proved conventional gas reserves

Conventional gas supplies are those that can be produced from gas reservoirs or in association with oil produced from reservoirs using conventional drilling techniques. Proved conventional reserves are the estimated quantities of conventional natural gas that geological and economic data demonstrate with reasonable certainty could be produced in future years from known reservoirs under existing economic and operating conditions.

As table 1 indicates, by the end of 2009, the United States had proved conventional gas reserves of 244.7 trillion cubic feet (Tcf). This is about three-quarters of total North American proved reserves, but only 3.7% of global proved reserves. Combined Canadian and Mexican proved natural gas reserves are about one-quarter of the continental total. North America as a whole holds approximately 4.9% of the world's proved conventional gas reserves (British Petroleum, 2010).

At the end of 2009, the US ranked 6th in the world in terms of proved conventional gas reserves. Its reserves are well below those of Russia (1,567.1 Tcf), Iran (1,045.7 Tcf), and Qatar (895.8 Tcf), but just slightly less than those of Saudi Arabia (279.7 Tcf). Canada, with almost 1% of world gas reserves, ranks 20th. Mexico ranks much lower on the global scale; its conventional natural gas reserves are less than one-third the size of Canada's (British Petroleum, 2010).

Table 1: Proved Conventional Natural Gas Reserves (as of December 2009, in trillions of cubic feet)

	Reserves	Percentage of North American Reserves	Percentage of World Reserves
Canada	62.0	19%	0.9%
Mexico	16.8	5%	0.3%
United States	244.7	76%	3.7%
North America	323.4	100%	4.9%
World	6,621.2	n/a	100%

Source: British Petroleum, 2010.

Unproved discovered and undiscovered natural gas resources

In addition to the proved natural gas reserves identified in table 1, Canada, the United States, and Mexico each have discovered natural gas resources that are not yet delineated or proved. They also have expected, but not yet discovered gas resources which, by comparison, are much greater, in total, than the proved reserves. This includes substantial volumes of unconventional gas resources including coal bed methane (CBM) in all three countries and, at least in Canada and the US, gas from tight sand and rock formations as well as from shale formations.[3]

Coal bed methane is natural gas that was created during the geological process in the same beds in which coal was formed. The gas is adsorbed on the internal surfaces of coal, which, because of their complexity, can store several times more natural gas than rock in a conventional reservoir. "Tight gas" refers to natural gas in tight sandstone or rock reservoirs. Such gas cannot be extracted at commercially viable rates without at least some fracturing to provide pathways for the gas to flow from the formation to the surface, generally in combination with multiple wells that are in closer proximity than they are with conventional gas, and/or by using horizontal drilling techniques. Shale gas is gas found in reservoirs composed mainly of shale, with correspondingly lesser amounts of other types of rock than is found in conventional limestone or sandstone reservoirs.

Because rapid technological advances have increased the potential for recovery of gas from tight sand and shale formations, estimates of the amount of unconventional recoverable gas resources in Canada and the United States are being revised upwards. Consequently, the North American natural gas supply and demand outlook has changed in just a few years from one in which the continent was expected to be heavily dependent on imported supplies of liquefied natural gas (LNG) by the 2020s, to one in which North America could soon be gas self-sufficient.

Unconventional gas is generally more difficult to produce than gas found in conventional oil and gas reservoirs because specialized drilling and production techniques are required to extract it. For this reason, until recently, unconventional natural gas production has generally been less economic than conventional gas production. However, improved technologies have allowed unconventional gas supplies to become more competitive. This is clearly the case with shale gas where horizontal drilling and

3 Until recently, the US Energy Information Administration considered tight gas resources as unconventional supplies. Canada's National Energy Board, on the other hand, has considered this source as part of the conventional gas resource base. In its 2010 *Annual Energy Outlook*, the EIA did include tight gas production with production from conventional operations (Energy Information Administration, 2010).

multiple location hydraulic fracturing are allowing greater volumes of gas to be produced from a single well, significantly improving the economics of doing so (Tristone Capital, 2008).

Methyl hydrates represent a huge potential source of natural gas that is yet to be tapped. Methyl hydrates are ice-like solids mostly found in arctic and deep water settings in which methane is trapped in water molecules. Because the gas is compressed by pressure and temperature, a single unit of gas in a hydrate formation is equivalent to 160 times as much gas once released. The US Geological Survey has indicated that the amount of gas contained in methyl hydrates in Alaska and offshore is staggering—in the range of 200,000 to 320,000 Tcf (United States Geological Survey, 2008: 27-28). ICF International Inc. experts estimate the total amount of gas in place in hydrates in the US at 303,384 Tcf (Vidas and Hugman, 2008).

There has been no commercial production of gas from methyl hydrates anywhere in the world because of the technological challenges and related costs. In order to release the gas from hydrate material the surrounding pressure must be lowered and/or the temperature increased. The shallower the formation and the less heating required, the greater the feasibility of commercial production. Similarly, the more permeable the formation, the more readily the gas will flow and the greater the likelihood of successful commercialization. For this reason, it is anticipated that hydrates found in sandstone formations, as is the case with about a third of the 21,400 Tcf of methyl hydrate gas estimated to be in place in the Gulf of Mexico, will be of considerable interest to investors as production methods develop.

There are no available estimates of the volume of gas that is technically recoverable from methyl hydrates. The United States Methane Hydrate Research and Development Act of 2000 (public law 106-193) authorized the Secretary of Energy to spend $47.5 million on methyl hydrate research, development, and exploration from 2001 to 2005 (United States Department of Energy, Office of Fossil Fuels, 2006). Some exploratory drilling was undertaken on the Alaskan North Slope under that program and the US Geological Survey is assessing the amount of gas that is technically recoverable there from methyl hydrates.

Canada

Table 2 shows Canada's "remaining marketable" natural gas resources by source as of the end of 2007. "Remaining resources" are proved reserves as well as discovered and undiscovered gas resources, both conventional and non-conventional, that are expected to be recoverable. (The natural gas resources indicated for Ontario, Quebec, and the Maritimes are not broken down into conventional or unconventional categories.)

The total remaining marketable gas resources shown in table 2 are more than 9 times the volume of Canadian proved reserves indicated in table 1. In the process of

Table 2: Canadian Natural Gas Resources by Type, 2007 year-end

Source of Gas	Remaining marketable resources (in trillions of cubic feet)	% of Total
Conventional	113	20%
Unconventional (including tight gas)	220	39%
Northern and offshore frontiers	225	40%
Ontario, Quebec, and Maritimes Basin	10	2%
Total	568	100%

Source: National Energy Board, 2009a, appendix table A4-1.

"proving" unproven reserves, the estimated size of the remaining resource base is influenced by the fact that not all of the currently unproven discovered and undiscovered resources are likely to be commercially viable. On the other hand, with further exploration and delineation, the estimated volume of unproven discovered resources is likely to increase. This is particularly the case with unconventional supplies, such as shale gas, where delineation of the extent of the resource in various regions of the US and Canada, including Alberta, is still in the early stages.

In its *2009 Reference Case Scenario*, the National Energy Board included 220 trillion cubic feet of unconventional gas resources in its reference case (National Energy Board, 2009a: 27, and appendix A4-1). The breakdown is shown in table 3.

Most of the 34 Tcf of producible coal bed methane (CBM) identified by the NEB is located in the relatively shallow Horseshoe Canyon and the deeper Mannville formations in Alberta. The remainder is in Nova Scotia.

By way of comparison, the Alberta Geological Survey estimates that Alberta has as much as 500 Tcf of CBM resources, but provides no indication as to how much of the resource is economically recoverable (Alberta Geological Survey, 2010). More recently, the Alberta Energy Resources Conservation Board has increased its estimate of remaining established Alberta CBM reserves to 2.3 Tcf from 1.0 Tcf (Energy Resources Conservation Board, 2010).[4]

CBM in areas of Canada other than Alberta and Nova Scotia is generally not regarded as economically recoverable. This is particularly the case where there is con-

4 According to the Energy Resources Conservation Board, established reserves are "those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing, or production plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty" (Energy Resources Conservation Board, 2010). Remaining established reserves are initial established reserves less cumulative production.

Table 3: Canada's Unconventional Gas Resources, 2007 year-end

Source	Estimated volume (in trillions of cubic feet)	Percent of unconventional
Coalbed Methane	34	16%
Tight Gas	104	47%
Shale Gas	82	37%
Total	220	100%

Source: National Energy Board, 2009a, appendix table A4-1.

siderable water present with the coal because the water, often in the form of brine, must be removed (to reduce the pressure) and disposed of, thus increasing the costs of production.

In 2007, the National Energy Board indicated that Canada had approximately 21 Tcf of producible tight gas in the "Deep Basin" along the Rocky Mountain fronts of Alberta and British Columbia, in the Jean Marie Formation of northeastern BC, and in shallow deposits in southeastern Alberta and southwestern Saskatchewan (National Energy Board, 2007, appendix 4, table A4.1). In its *2009 Reference Case Scenario*, the NEB made a large upward revision to its estimate of the size of the tight gas resource, taking it to 104 Tcf (National Energy Board, 2009a, appendix 4.1). The NEB indicates that virtually all of the tight gas is located in Western Canada, with approximately 85% situated in the recently discovered Montney play in northeastern British Columbia.

In addition, shale formations containing natural gas are now known to exist and are being explored in British Columbia, Alberta, Saskatchewan, Quebec, New Brunswick, and Nova Scotia, where horizontal drilling and multi-stage hydraulic fracturing of the shale (where appropriate) promise to make formerly uneconomic production feasible. As more information about the extent and nature of these formations becomes available, Canada's gas supply potential is being revised upwards, with parts of the country not previously known to hold significant quantities of natural gas, such as Quebec and New Brunswick, now finding that they could have considerable potential.

As recently as 2007, the National Energy Board report entitled *Canada's Energy Future* indicated that Canada had only 8.6 Tcf of gas reserves in shale formations and that no large-scale shale gas production programs were underway or likely (National Energy Board, 2007, appendix 4.1). The Board's July *2009 Reference Case*, on the other hand, indicated that as much as 82 Tcf of gas could be recoverable from Canadian gas shale formations. The NEB's *A Primer for Understanding Canadian Shale Gas*, released in November 2009, provides additional information on Canada's shale gas potential (National Energy Board, 2009a and 2009b.)

Based on limited, emerging information with respect to the Montney and Horn River plays in northeastern British Columbia where gas production from shale formations is already underway, the National Energy Board's November 2009 report indicates that BC could hold at least 1,000 Tcf of shale gas resources. Moreover, the Colorado shale formation that runs through much of Alberta and Saskatchewan could possibly have more than 100 Tcf of shale gas, the Utica shale formation in Quebec more than 120 Tcf, and the Horton Bluff formations in Nova Scotia and New Brunswick at least 130 Tcf (National Energy Board, 2009b).

If, as the Board's report indicates, 20% of the gas in shale formations is recoverable, potential Canadian production from this source alone could be in the vicinity of 270 Tcf. Given the very early stage of efforts to delineate the size of the shale gas resource and the recoverable potential, even this estimate could turn out to be low. Environmental challenges such as water requirements for underground fracturing processes and greenhouse gas emissions from the carbon dioxide that in some cases is mixed with the gas will bring additional costs and delay and inhibit production to some extent. On the other hand, continued technological progress and on-site knowledge and experience will help to reduce production costs. Further, in situations like the Montney formation where the shale play is sufficiently thick or where one shale formation overlies another, as with the Utica and Lorraine shale, recovery operations at one level may be followed by operations at another, in many cases using the same wells.

The United States

The US Energy Information Administration's most recent perspective on the country's "technically recoverable" gas resources is summarized in table 4. As defined by the EIA, technically recoverable resources are gas accumulations producible using current recovery technology but without reference to economic profitability factors. Undiscovered resources are located outside of oil and gas fields in which the presence of resources has been confirmed by exploratory drilling. They include resources from undiscovered pools within confirmed fields only if they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions. Inferred reserves include that part of expected ultimate gas recovery from known fields in excess of gas already produced plus current proved reserves.

US coal bed methane proved reserves are estimated by the Energy Information Administration to be approximately 22 Tcf (Energy Information Administration,

Table 4: Technically Recoverable Natural Gas Resources as of Jan. 1, 2008 (in trillions of cubic feet)

Lower 48 Non-Associated Conventional Gas (Inferred or Undiscovered)		
Lower 48 Onshore	740.0	
Lower 48 Offshore	283.7	
Subtotal		1,023.7
Lower 48 Associated Undiscovered Gas	117.2	
Subtotal		117.2
Lower 48 Unconventional Gas (Inferred or undiscovered)		
Shale Gas	346.5	
Coalbed Methane	102.7	
Subtotal		449.2
Total Lower 48 Unproved Resources	1,590.1	
Alaska Inferred or Undiscovered	290.9	
Subtotal		290.9
Total Unproved Resources	1,881.0	
Total Proved Reserves	237.7	
Subtotal		237.7
Total		**2,118.7**

Source: Energy Information Administration, 2010b, assumptions table 9.2.

2009a).[5] Almost 55% of US CBM reserves are located in Colorado and New Mexico. Another 36% are in Wyoming, Alabama, Virginia, and Utah. The remaining 9% are distributed among 13 other coal-mining states.

When preparing its 2010 Annual Energy Outlook, the EIA assumed (see table 4) that the volume of technically recoverable gas from coal beds in the lower 48 states, including proved reserves, was 124.6 Tcf (102.7 Tcf of unproved CBM reserves, plus 21.9 Tcf of proved CBM reserves). However, in its most recent report, the highly regarded Potential Gas Committee estimated the size of the US CBM resource at 163 Tcf, excluding proved reserves (Colorado School of Mines, 2009). This suggests that the Energy Information Administration's estimate of the extent of gas recoverable from coal seams is on the conservative side.

5 Because CBM supplies are regarded as "unconventional," that amount is not contained in the US conventional proved gas reserves presented in table 1.

In its 2010 Annual Energy Outlook, the Energy Information Administration included tight gas with conventional gas and, therefore, provided no separate estimate. The estimate of undiscovered technically recoverable tight gas that the EIA used when preparing the 2009 Annual Energy Outlook was 310 Tcf (Energy Information Administration, 2009b, table 9.2). It indicated that nearly 60% of the assumed tight gas resources fall in the Rocky Mountain region where future development will depend on sufficient transportation capacity being available to ship the incremental production to market. The Permian and Anadarko Basins in Texas, which spill over into adjacent states, and the Appalachian Basin in the northeast, also hold considerable quantities of tight gas.

US tight gas resources are likely greater than 310 Tcf. This is because resources delineated after January 1, 2007, are not included in the estimate. Further, a December 2008 study of potential North American unconventional gas supplies by ICF International Inc. indicated that, based only on what had been taking place in East Texas and in the Wyoming/Colorado/Utah regions, "the current estimates of tight gas potential look conservative … it is unlikely that they reflect recent advances in completion technology" (Vidas and Hugman, 2008). Another report suggests that the amount of tight gas in place may be in excess of 5,000 Tcf (Dar, 2009). These reports suggest that recoverable volumes of US tight gas are likely to be considerably greater than the Energy Information Administration has assumed.

Table 4 indicates that the US also has considerable potential gas production from shale formations, with technically recoverable volumes from inferred reserves and undiscovered technically recoverable resources in excess of 346 Tcf—about 368 Tcf if proved shale gas reserves are included. An indication that the Energy Information Administration's estimate of gas recoverable from shale formations may also be on the conservative side is the Potential Gas Committee's finding of an "unprecedented" increase in estimated US natural gas resources in its latest biennial report (Colorado School of Mines, 2009) and that most of the increase, from 1,321 Tcf in 2006 to 1,836 Tcf in 2008, "arose from the reevaluation of shale-gas plays in the Appalachian Basin and in the Mid-Continent, Gulf Coast and Rocky Mountain areas." In fact, at 616 Tcf, shale gas accounts for one third of the Potential Gas Committee's revised estimate of potential US gas resources.[6]

In their 2008 study for the Interstate Natural Gas Association of America [INGAA] Foundation, Vidas and Hugman placed the recoverable amount of gas resources from US shale gas at 385 Tcf, also considerably greater than the Energy Administration's January 1, 2008 estimate (Vidas and Hugman, 2008). An even more

6 The Potential Gas Committee does not include proved reserves in its definition of potential resources. In the Committee's scheme, the sum of probable, possible, and speculative resources equals potential resources, and potential resources plus proved reserves equal "future supply."

dramatic indication of the extent to which US shale gas resource estimates are increasing is the view that Professor Terry Engelder expressed in an August 2009 article. According to Engelder, the Appalachian Basin Marcellus shale formation holds 2,445 Tcf of natural gas and there is a 50% chance that the Marcellus shale alone will ultimately yield 489 Tcf of produced gas (Engelder, 2009). This compares with the indication only eight years ago by the US Geological Survey in its 2002 *Assessment of Undiscovered Oil and Gas Resources of the Appalachian Basin Province* that the Marcellus shale contains 1.9 Tcf of gas (Considine et al., 2009).

Mexico

There is no publicly available information on the presence and size of known or potential tight gas resources in Mexico. Similarly, no information was located as to the presence or size of known or potential supplies of natural gas from shale formations in that country. However, it is likely that the size of Mexico's natural gas resource is substantially greater than the estimate of 16.8 Tcf of conventional proved reserves included in table 1. This argument is supported by Petroleos Mexicanos (PEMEX), Mexico's state-owned oil company, which has indicated that the country has 20.1 Tcf of "probable" gas reserves and 22.6 Tcf of "possible" reserves in accordance with the generally accepted definitions of those terms (PEMEX, 2009).[7] Further, information obtained from Mexico's Secretaria de Energia indicates that the country has approximately 6.9 Tcf of producible CBM.[8]

The extent of North America's natural gas resources

Table 5 summarizes the North American gas resource picture based on the estimates already presented. The 2,755 Tcf of total proved reserves, inferred reserves, and undiscovered technically recoverable gas resources recognized by government agencies in the three countries represents sufficient supply to meet North American gas demand for 96 years at 2009 consumption rates.[9]

The "likely additional unconventional" line in table 5 refers to additional gas resources that are likely to be available in view of the outlook for coal bed methane,

7 In the gas resource summary table (table 5) presented later in this report, the sum of probable and possible gas reserves are shown as "inferred or undiscovered resources."

8 Approximately 60% of Mexico's CBM resource is located in the Sabinas Basin in northern Mexico, which has substantial coal deposits.

9 According to the 2010 *BP Statistical Review of World Energy*, North American natural gas consumption averaged 78.5 Bcf per day in 2009, for a 2009 total of 28.5 Tcf (British Petroleum, 2010).

Table 5: Recoverable North American Natural Gas Resources (in trillions of cubic feet)

Resource type	US	Canada**	Mexico	Total
Proved reserves*	226	62	18	306
Offshore: Inferred or undiscovered*	284	225	n/a	509
Conventional onshore: Inferred or undiscovered*	740	61	43	844
Associated: Inferred or undiscovered*	117	n/a	n/a	117
Alaska	302	n/a	n/a	302
Unconventional: Tight*	n/a	104	n/a	104
Shale gas: Inferred or undiscovered*	347	82	n/a	429
Coalbed methane: Inferred or undiscovered*	103	34	7	144
Subtotal	2,119	568	68	2,755
Likely additional unconventional	300	200	20	520
Total	2,419	768	88	3,275

*The US lower 48 states only. For the US, tight gas is included with conventional gas. For Canada and Mexico, the proved reserve estimates are from the BP 2010 *Statistical Review*.
**Except as noted, the Canadian estimates are components of "remaining marketable resources" as defined by the National Energy Board.
Source: BP, 2010; Energy Information Administration, 2010b; National Energy Board, 2009a; PEMEX, 2009, and Fraser Institute, author calculations.

tight gas, and shale gas. This addition is rather conservative given the information that is emerging about the potential size of unconventional gas resources. With it, North America could have 3,275 Tcf of technically recoverable gas supplies, sufficient to meet current requirements for more than 100 years. This estimate ignores the prospect of further additions to the volume of technically recoverable gas resources as the result of further exploration and technological improvements. It also ignores any prospect of production of natural gas from methyl hydrates.

Natural gas prices, 1989–2009

As figure 1 indicates, the prices at which natural gas has been trading in two of North America's established regional markets, Henry Hub and AECO, have been fairly volatile over the past 21 years, but more so over the last decade.[10]

From 1989 through 1999, the Henry Hub price, the key US marker price for natural gas, increased from $1.65/mcf (thousand cubic feet) to $2.20/mcf, and averaged $1.94/mcf. During the same period, the AECO (Alberta market) price averaged $1.23/mcf. The difference between prices in the 2 market hubs, which mainly reflects transportation costs, averaged about $0.71 per mcf during the period but jumped to $1.59/mcf in 1996. The spike in the price differential in 1996 was caused by a number of factors including unusually cold weather in the US, a slowdown in net gas imports from Canada, an interruption in US coal deliveries, and low storage levels (Herbert, Thompson, and Todaro, 1997).

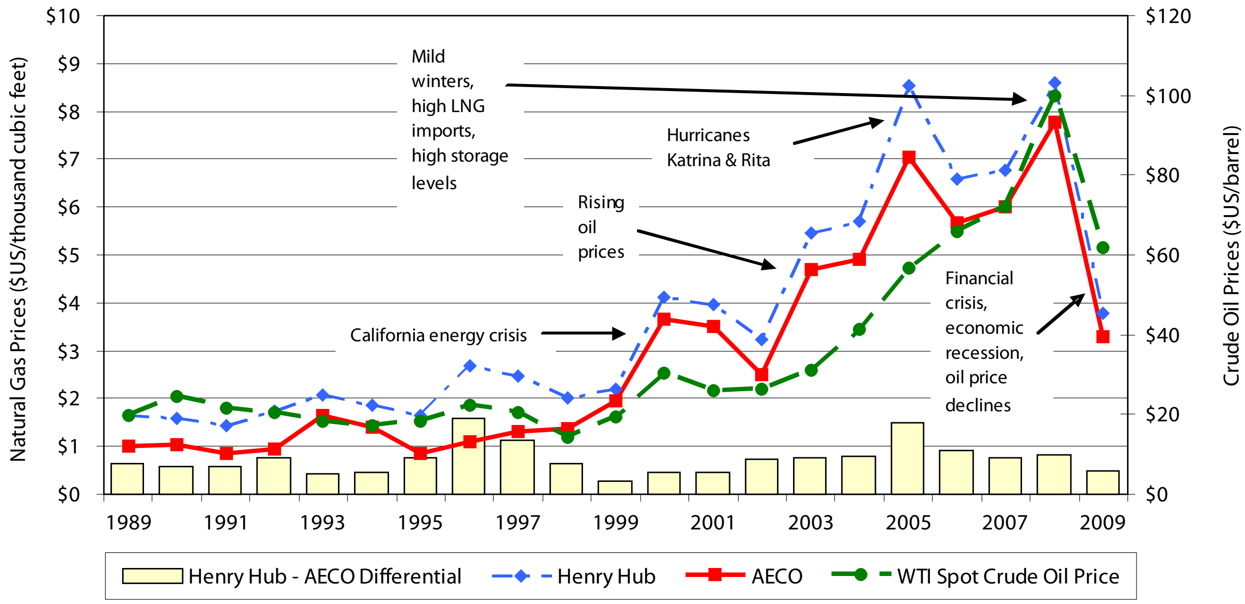
During the 2000 to 2004 period, prices at Henry Hub and AECO increased substantially, reaching $5.69/mcf and $4.89/mcf in 2004. The main reason for the natural gas price increase in this period was the increase in the price of crude oil.[11] A rise in US gas demand for electric generation and fluctuations in those requirements also help to explain both the increase in the level of gas prices and their volatility during this period (Energy Information Administration, 2010h).

From 2005 to 2008, natural gas prices were very volatile and were much higher on average than previously. Average Henry Hub and AECO prices surged to $8.55/mcf and $7.05/mcf respectively in 2005 due to interruptions in US gas production caused by hurricanes Katrina and Rita, and the price differential rose to $1.49/mcf. During 2006, prices at both market hubs fell by about 20% but remained above their pre-2005 levels. Prices increased only slightly during 2007 as increased gas demand was met by increased LNG imports, rising US gas production, and net draws from storage. In 2008, driven in part by higher crude oil prices, average annual prices at Henry Hub ($8.61/mcf) and AECO ($7.77) exceeded the highs established in 2005.

10 The prices referred to here are the prices at which producers, traders (including exporters and importers), major industrial consumers, and distributors are able to buy and sell large volumes of natural gas. The Henry Hub price is the price at the major Henry Hub in Louisiana where a number of major natural gas transmission pipes intersect. The AECO price is the price of natural gas on TransCanada's Alberta gas transmission system, i.e., the so-called NOVA inventory transfer (NIT) price.

11 The average price of West Texas Intermediate (WTI) crude oil increased to $31.00/barrel from 2000 to 2004 compared with an average price of $19.71/barrel from 1989 to 1999. WTI is widely used as the benchmark price for North America crude oils.

Figure 1: Natural Gas and Crude Oil Prices in North America, 1989-2009



Source: British Petroleum, 2010.

During 2009, natural gas prices at the 2 market hubs fell by 57% from their 2008 levels, reaching $3.79/mcf and $3.29/mcf, respectively, about the same as in 2001. The price drop resulted from a combination of factors, including weaker industrial and commercial sector demand on account of the recession,[12] sharply lower oil prices, and increased shale gas production. At the time of writing, these factors have continued to suppress gas prices. Compared with the average 2004-2008 levels, average prices at Henry Hub ($4.22/mcf) and AECO ($3.24/mcf) in August 2010 were 45% and 48% lower, respectively (Energy Information Administration, 2010g; Natural Resources Canada, 2010).

12 This excludes demand from the electric power generation sector.

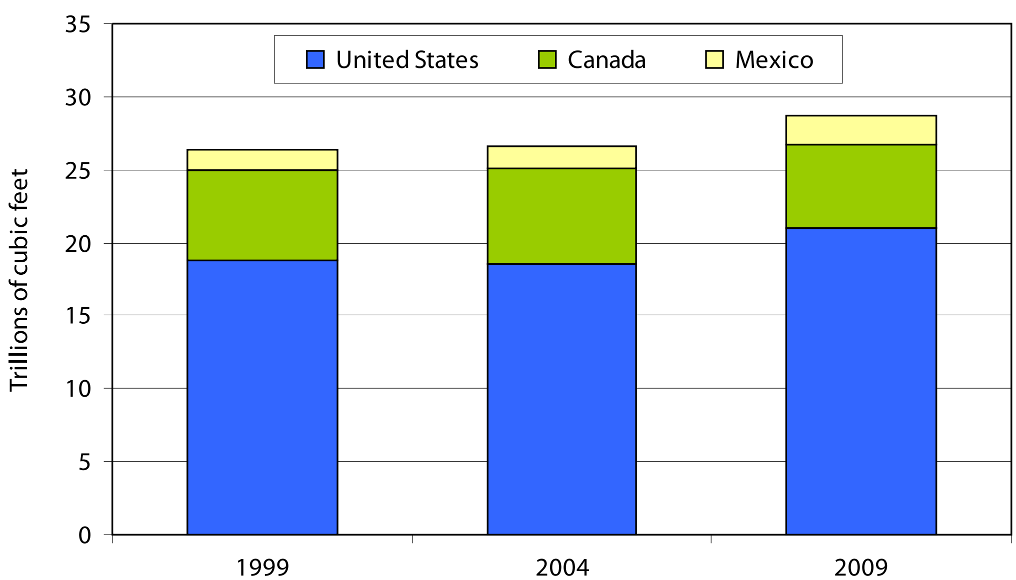
Natural gas production

This section begins with a brief discussion of natural gas production volumes in Canada, the United States, and Mexico, and how those levels have changed during the past decade. The focus then shifts to projections of gas production levels in the three countries to 2030. Although the forecasts are from reputable sources, note that in each case they are conditional, in that they are based on unique assumptions about the key drivers.

Figure 2 illustrates how total natural gas production has developed in Mexico, Canada, and the United States since 1999. US gas production increased at a 1.1% compound annual growth rate from 1999 to 2009. Much of the increase occurred from 2006 to 2009 when improved technologies made production from shale and tight gas formations more viable.

Canadian gas production declined at a compound annual rate of 0.8% from 1999 to 2009 because of declining conventional production in the maturing Western Canada Sedimentary Basin. The overall decline would have been more substantial were it not for commencement of operations at newly developed shale and tight gas produc-

Figure 2: North American Natural Gas Production by Country, 1999–2009 (in trillions of cubic feet)



Source: British Petroleum, 2010.

Table 6: North American Natural Gas Production, 2010–2030 (in trillions of cubic feet)

Region	2010	2015	2020	2030
Canada	5.2	5.4	5.8	5.9
Mexico	1.8	1.9	2.1	2.1
United States	20.0	19.3	20.0	22.4
North America	27.0	26.6	27.9	30.4

Sources: Energy Information Administration, 2010a and 2010d for the US and Mexico; National Energy Board, 2009a; and Fraser Institute author extrapolations for Canada.

tion facilities in northeastern British Columbia and gas production from coal beds in Alberta.

Mexican production increased considerably during the past decade (at a 4.1% compound annual growth rate) as the result of intensified efforts to develop the non-associated gas resources in the country's north.

The United States is North America's largest producer of natural gas, accounting for 73.0% of the continent's gas production in 2009. The Canadian and Mexican shares of continental gas production were 19.9% and 7.1%, respectively.

Table 6 summarizes the outlook for gas production in the three countries and for the continent as a whole to 2030. The production forecasts for the US and Mexico are from the Energy Information Administration's 2010 *Annual Energy Outlook* and *International Energy Outlook*, respectively. The Canadian projection is from the National Energy Board's July *2009 Reference Case Scenario* extrapolated from 2020 to 2030.[13] According to these projections, the US share of North American natural gas production would decline slightly from 2010 to 2030, while Canada's share would essentially remain unchanged.

Mexico's share of continental gas production increases during the forecast period, although only marginally so. All of the increase occurs during the next 10 years.

13 As indicated in table 6, Canadian gas production is essentially unchanged in 2030 from 2020 as increased output from unconventional sources and offshore frontier areas is mostly offset by declining production in the Western Canada Sedimentary Basin. Details of the Canadian forecast and the assumptions that were used to extrapolate the National Energy Board's 2009 reference case forecast from 2020 to 2030 are provided later in the discussion.

Canadian gas production outlook

Canadian conventional natural gas production, as projected by the National Energy Board to 2020 and extrapolated to 2030, points to a decline of 34% from 2010 to 2030. Figure 3 illustrates that conventional output is forecast to fall from about 3.0 Tcf to 2.0 Tcf as declining production from mature wells in the Western Canada Sedimentary Basin more than offsets production from new discoveries of conventional gas resources.[14] The forecast assumes that the Mackenzie Valley Pipeline is constructed with deliveries commencing at 0.8 billion cubic feet per day (Bcfd) in 2017, rising to 1.2 Bcfd the following year. Unconventional gas production is projected to increase strongly, from 2.1 Tcf in 2010 to 3.9 Tcf in 2030.

The National Energy Board's detailed projection of unconventional Canadian gas production to 2020, with extrapolations to 2030 added, is illustrated in figure 4.

Virtually all of Canada's coal bed methane production is in Alberta. Close to 85% is from the Horseshoe Canyon zone where the coal is relatively dry and there is little problem or expensive water removal. About 15% of CBM production is from coals in the upper Mannville geologic formation where the gas content, though generally higher than the Horseshoe Canyon coals, is often accompanied by high volumes of saline water, which requires extensive pumping and disposal. Alberta CBM production has grown dramatically from only 0.05 billion cubic feet per day in 2001 to 0.87 Bcfd in 2009 (Energy Resources Conservation Board, 2010).

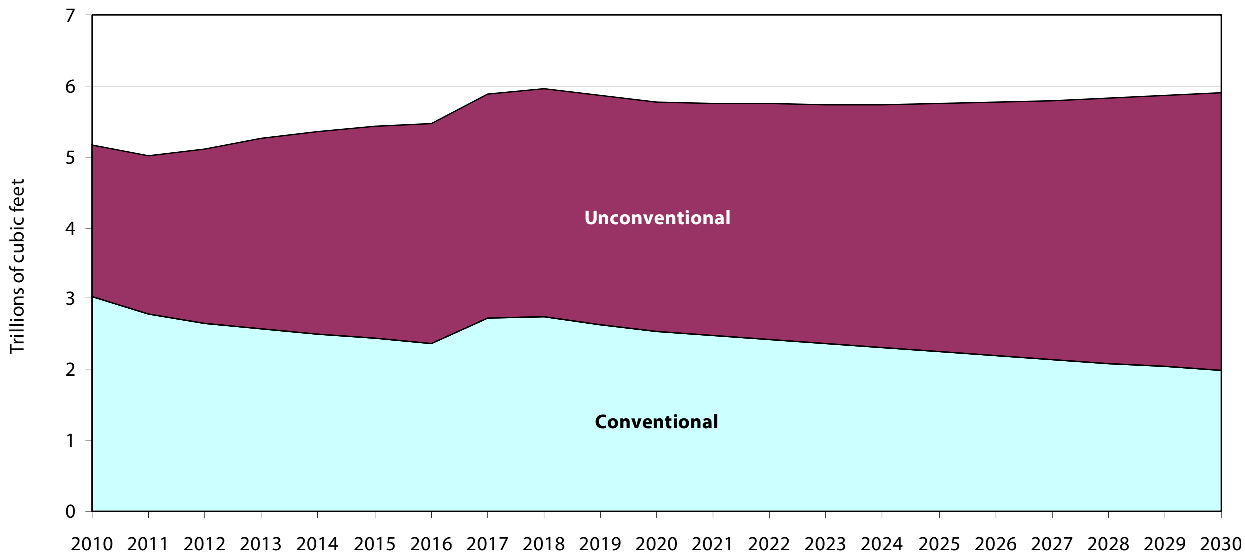
In its July *2009 Reference Case Scenario,* the National Energy Board assumed that CBM production would commence in Nova Scotia in 2009, reach 0.05 Bcfd there in 2010, and remain constant at that level through the forecast period (National Energy Board 2009a).[15] In total, the National Energy Board's reference case has Canadian CBM production growth slowing during the next few years, peaking at 1.04 Bcfd in 2015, and then dropping to 1.0 Bcfd by 2020. The outlook for slower CBM production growth and then declining production is attributed to concerns regarding access to freehold lands, higher costs, softer prices, rapid rates of decline in the initial production rates of new wells, and competing opportunities for investment such as in tight gas and shale gas developments in northeastern BC.

The actual Alberta CBM production rate in 2009 of 0.87 Bcfd compares with the National Energy Board's estimate of 0.75 Bcfd (Energy Resources Conservation Board,

14 The projection of Canadian conventional gas production beyond 2020 assumes that the approximate compound annual decline rate of 2.5% predicted to occur from 2017 to 2020 in the National Energy Board's reference case continues beyond 2020.

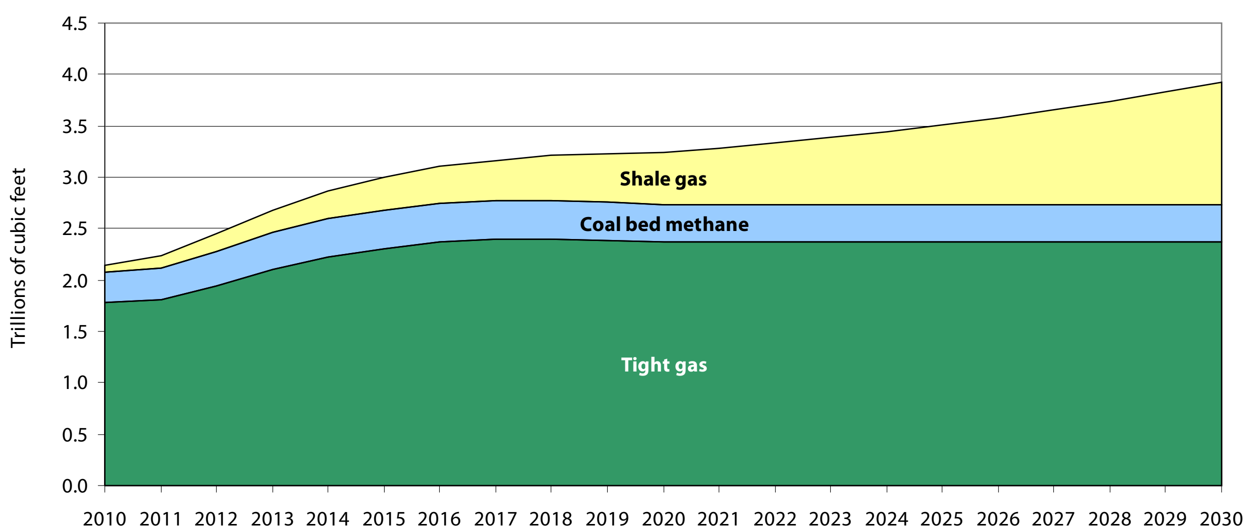
15 In fact, while Nova Scotia has CBM production potential, and production agreements have recently been entered into with several companies, no CBM production was underway in Nova Scotia at time of writing (Nova Scotia Department of Energy and Mines, 2010).

Figure 3: Canadian Conventional and Unconventional Natural Gas Production, 2010–2030 (in trillions of cubic feet)



Source: National Energy Board, 2009a, figure 6-2; and Fraser Institute author calculations.

Figure 4: Canadian Unconventional Gas Production, 2010–2030 (in trillions of cubic feet)



Source: National Energy Board, 2009a, figure 6-2; and Fraser Institute author calculations.

2010; and National Energy Board, 2009a). Further, the Energy Resources Conservation Board Alberta CBM production rate projection for 2019 (the final year of its latest projection) of 1.47 Bcfd compares with the National Energy Board's Alberta projection for that year of 0.96 Bcfd. This suggests that, depending on the price of gas and other factors, Canadian CBM production could be significantly greater in 2020 than the 1.0 Bcfd rate indicated in the National Energy Board's *2009 Reference Case*.

For the purpose of extrapolating the National Energy Board's reference case for Canadian CBM production forecast beyond 2020, it was assumed that production would remain at the 2020 rate through the forecast period. Given the information in the Energy Resources Conservation Board's 2010 report mentioned above, this approach may have been too conservative.

In its fall 2008 gas deliverability outlook, the National Energy Board indicated that it expected production of gas from tight formations to increase thanks to the widespread application of new and improved deep horizontal drilling and fracturing techniques, especially in northeastern BC (National Energy Board, 2008: 16). Consistent with this prediction, in its July *2009 Reference Case Scenario,* the National Energy Board anticipated that production from tight sandstone formations in the Western Canada Sedimentary Basin would increase by 30% from 5.0 Bcfd (or about 1.8 Tcf annually in 2010) to 6.5 Bcfd (or about 2.4 Tcf per year by 2020) (National Energy Board 2009a, figure 6.2). It is noteworthy that all of the anticipated growth is in the Montney play and elsewhere in northeastern British Columbia where the production rate is expected to quadruple from 0.93 Bcfd in 2008 to 3.73 Bcfd in 2030. Production from tight gas formations in Alberta and Saskatchewan was projected to decline during the forecast period because of declining rates in existing wells and higher royalties in Alberta.

For the extrapolation of Canadian tight gas production from 2020 to 2030, it was assumed that the almost negligible compound annual growth rate implicit in the National Energy Board's projections for the period from 2016 to 2020 would continue. Consequently, the projected annual production in 2030 is only marginally greater than in 2020.

The National Energy Board's 2009 reference case projections show gas production from shale formations increasing from only 0.1 Tcf in 2010 to 0.5 Tcf in 2020. For extrapolation purposes it was assumed that the 9% compound annual growth rate for shale gas production implicit in the Board's forecast for the 2016-2020 period would continue. As a consequence, annual gas production from shale formations is projected to reach 1.2 Tcf by 2030.

The areas in Canada that have sparked the most interest for shale gas are the Horn River Basin, the Cordova Embayment, the Upper Montney play in British Columbia, and the Utica shale formation in Quebec. Since September 2006 a number of companies have undertaken experimental drilling in the Horn River Basin and

Cordova Embayment in an effort to learn about the extent of the gas resource and the most promising production methodologies. Because the results of experimental schemes remain confidential for three years, it will be some time before the public will learn about the amount of gas that is economically recoverable. However, based on the interest in BC exploration indicated by the results of land sales during 2008 and 2009, and a Tristone Capital study released in October 2008, it is widely believed that the BC shale formations hold considerable promise (Tristone Capital, 2008).

Commercial production from shale gas in the Upper Montney area began in 2007. In its July *2009 Reference Case Scenario,* the National Energy Board projects that gas production from the BC and the Quebec Utica shale sites will grow from only 0.01 Bcfd in 2008 to 1.1 Bcfd in 2018 and reach a 1.3 Bcfd rate by 2020.[16] By way of comparison, the Tristone Capital analysis undertaken during the summer and early fall of 2008 suggested that, led by fairly rapid production development from the Horn River and Montney plays, but with production also emerging in the Utica play in the Quebec lowlands, production from Canadian shale gas formations would likely reach 0.6 Bcfd in 2008 and grow to 5.3 Bcfd (ie., an annual rate approaching 0.2 Tcf) by 2018 (Tristone Capital, 2008: 166).

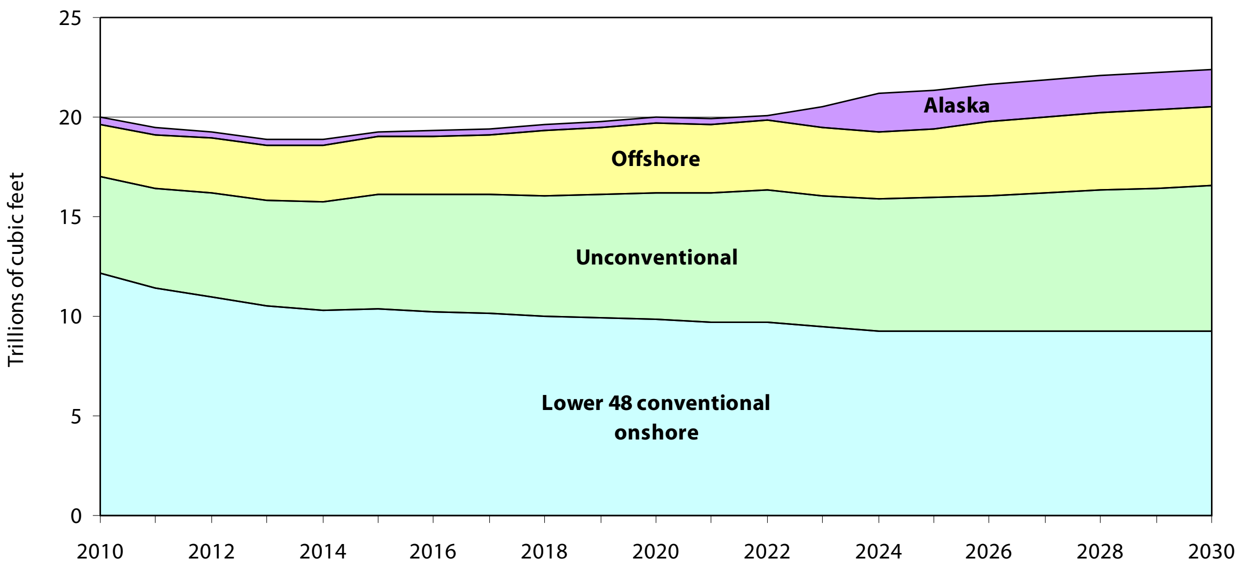
US gas production outlook

Table 6 indicates that from 2010 to 2030, North American gas production is projected to increase by 3.4 Tcf, or 12.6%. Most of the increase is expected to be in the US where annual production is anticipated to increase by 2.4 Tcf (12.0%) to 22.4 Tcf during the 20-year period. This is comparable to the International Energy Agency's 2009 *World Energy Outlook* indication for US natural gas production, which projects US production to reach 22.6 Tcf by 2030 (International Energy Agency, 2009). Both forecasts assume construction of an Alaskan gas pipeline. In the 2009 *World Energy Outlook,* declines in CBM and tight gas production, in combination with a steady decline in conventional gas production, come close to offsetting increased production from shale formations.

As figure 5 illustrates, the US Energy Information Administration is anticipating conventional gas production in the lower 48 states, including production from tight formations, to decline substantially from 2010 to 2030 (Energy Information Administration, 2010a, table 14). However, it projects that declines in conventional production will be more than offset by production increases from unconventional supply sources, especially shale gas (as shown in figure 5), and from the offshore and Alaska.

16 The assumed contribution from Quebec shale gas commences in 2010 at only 0.04 Bcfd and does not increase above that rate.

Figure 5: US Natural Gas Production, 2010–2030



Source: Energy Information Administration, 2010a, table 14.

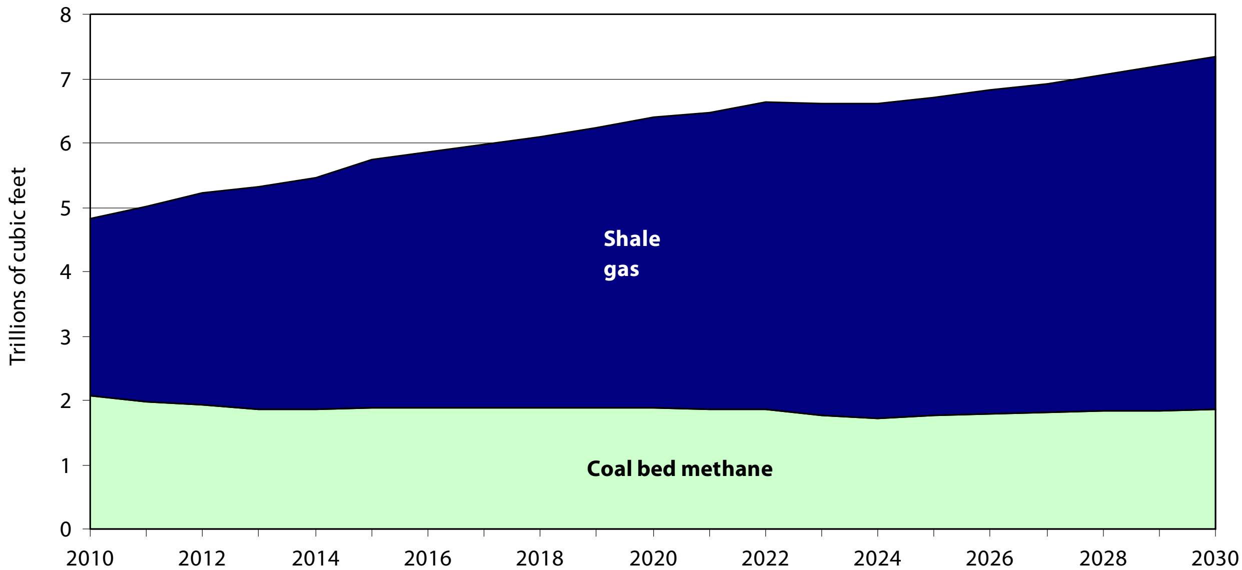
The Energy Information Administration is projecting conventional onshore gas production (including tight gas and gas associated with oil) in the lower 48 states to drop from 12.18 Tcf in 2010 to 9.25 Tcf in 2030, a compound annual decline rate of nearly 1.4%.

Projected compound annual growth of almost 2% in offshore gas production is partly based on the anticipated outcome of the Bush administration's lifting of certain congressional moratoria on offshore drilling in 2008. Offshore production is forecast to increase from 2.65 Tcf in 2010 to 3.91 Tcf in 2030. However, such growth could be dampened by repercussions from the BP Deepwater Horizon oil leak in the US Gulf of Mexico.[17]

Alaskan gas production is indicated by the Energy Information Administration to increase from 0.4 Tcf in 2010 to 1.9 Tcf in 2030. All of the increase is projected to occur during 2023 and 2024 when a natural gas pipeline from Alaska to Alberta is assumed to begin operating.

17 On May 27, 2010, the US Department of the Interior issued a six-month moratorium on offshore deep-water drilling in response to the BP oil spill. While the moratorium has since been lifted, the tightening of safety and environmental regulations in relation to offshore exploration, as well as increased liability insurance premiums, will add to the cost and may lead some investors to turn to other opportunities.

Figure 6: Unconventional Natural Gas Production in the United States, 2010–2030



Source: Energy Information Administration, 2010a, table 14.

Unconventional US natural gas production, comprising gas from shale formations and coal bed methane, is projected by the US Energy Administration to increase substantially during the forecast period, as illustrated in figure 6. Unconventional gas production is forecast to increase from 4.8 Tcf in 2010 to 7.4 Tcf in 2030. All of this growth is expected to come from shale gas as coal bed methane production is projected to decline through most of the period.[18]

Gas production from shale is anticipated to double from 2.75 Tcf in 2010 to 5.50 Tcf in 2030. This reflects the considerable technological progress that has been made in producing gas from shale formations. Production from the large Barnett shale formation in Texas where most of the activity has been focused increased from only 94 million cubic feet per day in 1998 to 3,014 million cubic feet per day in 2007. The key to this success has been the application of horizontal drilling techniques in combination with multi-zone hydraulic fracturing. This technique is allowing shale gas resources to be developed and produced in sufficiently large volumes to be economic.

18 From only 91 billion cubic feet in 1989, US CBM production has increased to an annual production rate of about 2 Tcf. Approximately three quarters of CBM activity is concentrated in Colorado, New Mexico, and Wyoming.

While the US Energy Information Administration has increased its projection of shale gas production considerably during the past two years, the current forecast may still be too conservative. For example, in one study, the widespread application of the techniques that have been successful in Texas are expected to increase the annual productive capacity from large shale gas plays to at least 6.6 Tcf by 2018 (Navigant Consulting Inc., 2008). A projection developed from a slightly smaller and different group of large US shale gas plays predicts an annual production rate of at least 6.9 Tcf by 2018 (Tristone Capital, 2008: 168).[19] (These projections compare with the 2018 shale gas production forecast of 4.2 Tcf in the Energy Information Administration's 2010 *Annual Energy Outlook*.) Another projection indicates that the production of gas from US shale formations could reach 8 Tcf in 2030 compared with the Energy Information Agency's 2010 *Annual Energy Outlook* forecast of 5.5 Tcf (Navigant Consulting Inc., 2010).

Mexican gas production outlook

Mexican annual gas production is projected to increase by only about 0.3 Tcf from 2010 to 2030 (Energy Information Administration, 2010d). As noted later in this paper, such a modest increase in production would lead to Mexico becoming more dependent on imported natural gas supplies.

North American gas production outlook overview

From a continental perspective, gas from unconventional sources appears poised to make a major contribution to gas supply. Production growth will largely depend on market conditions (prices) as well as the applicable fiscal regimes. Clearly defined and understood land access rules, effective dispute resolution procedures, and efficient regulatory approvals processes will also influence the degree of success that the competing states, provinces, and federal districts and territories have in attracting investment in natural gas exploration and development. With an appropriate policy framework, unconventional supplies and gas from the outer continental shelf and the northern frontier have the potential to offset declining conventional production and lead North America into an era of gas self-sufficiency.

19 The year 2018 is used for these comparisons because it is the final year in the projections provided by each of the referenced parties.

Uncertainties underlying the production outlook

A number of risks and uncertainties are associated with the long-term natural gas production forecasts reported here. These include, but are not limited, to the following:

Natural gas prices

Production levels are particularly sensitive to natural gas prices because the price directly affects a gas producer's return on investment. The Energy Information Administration's *Annual Energy Outlook* 2010 reference case projects that the US lower-48 wellhead price of natural gas will average US $5.69/mcf (in constant 2008 dollars) in 2015 and increase to US $7.31/mcf by 2030 (which is below the $8.07/mcf average for 2008) (Energy Information Administration, 2010a). In its *2009 Reference Case Scenario*, the National Energy Board assumes a more aggressive trajectory, with the real price of gas reaching US $6.70/mcf in 2011 and US $7.50/mcf by 2020 (National Energy Board, 2009a).[20]

Other things being equal, price trajectories that are at all different from those used in the reported forecasts can be expected to yield different gas production projections.. However, as indicated by the price fluctuations that occured during the 1989 to 2009 period, forecasting the price of natural gas presents a considerable challenge.

Uncertainty regarding environmental policy

Continued uncertainty at the state, provincial, and federal levels with regard to the volume of required reductions in emissions of carbon dioxide and other greenhouse gases, and their timing, is making it difficult for potential investors to make decisions. This is particularly true in the case of new gas processing facilities where greenhouse gas emissions per unit of output are greater than in the production of raw gas. The re-

20 The National Energy Board's assumptions compare with the Energy Information Administration's natural gas price assumptions for 2011 and 2020 of US $5.16/mcf and US $6.03/mcf, respectively. The difference in the assumed gas price trajectories indicate that the Canadian and US demand forecasts are inconsistent and are not comparable for that reason.

quired emissions abatement equipment and related installation costs will add to the capital cost. Uncertainty surrounding the extent of the incremental cost can cause investment decisions to be deferred or project plans to be shelved.

Not knowing the nature and extent of new regulations that may apply is also of concern in the case of proposed new natural gas pipelines and extensions, or the looping of existing lines, since pipeline gas compressors are a significant source of greenhouse gas emissions.

Another example of environmental policy ambiguity affecting natural gas industry investment relates to uncertainty about the nature and extent of possible regulations that would constrain production from gas shale formations due to concerns about water supplies.

Speculative nature of unconventional and frontier gas supply projections

Production projections for unconventional and frontier (including outer continental shelf) gas supplies tend to be less accurate than production forecasts for conventional sources. There are a number of reasons for this. For example, unconventional and frontier supply sources are generally more costly to produce and deliver to key market hubs than conventional supplies and, therefore, more sensitive to price fluctuations and changes in royalties. Further, in the case of unconventional gas operations such as shale formations, production volumes are less certain because of the more complex nature of the processes employed, and unknown initial production and production decline rates. With regard to frontier gas production, the fact that there has been less cumulative past exploration than in the non-frontier areas makes for greater uncertainty. Also, major new pipelines will be needed for which the construction completion dates assumed in long-term supply forecasts are subject to change as with the proposed pipelines from the Mackenzie Delta and Alaska.

Moratoria on offshore exploration and production

Moratoria on offshore exploration and development as in British Columbia and parts of the US (see US Department of Interior, 2010a and 2010b) close the door on investment in exploration and production. Incorrect assumptions that such moratoria will be removed will result in unattainable production forecasts for such areas.

Where moratoria are lifted, one cannot assume that a flurry of investment activity will follow. Investors' plans must fit with the area development plans prepared by the US Department of the Interior or other government agencies. Such plans can also be delayed or blocked by changes in the extent of public opposition to the development of offshore production for environmental reasons as a consequence of a major disaster such as the BP Deepwater Horizon oil leak. Further, the extent and pace of development will be sensitive to market conditions and royalties.

Pipeline approval regulation processes and procedures

Regulatory processes and procedures that unnecessarily delay the approval of natural gas pipeline projects can cause investors to terminate or cutback exploration in areas where new transportation infrastructure is essential to connect planned gas production to market hubs. For example, the Mackenzie Gas Project proponents applied to the National Energy Board for approval to construct a pipeline from the Mackenzie River Delta to the Alberta border and a natural gas gathering system to supply the pipeline in October 2004, but the board is not expected to issue a decision before December 2010. Given the immense change in the North American gas supply outlook since 2004 as a result of the increased feasibility of recovering gas from shale formations, the project economics are probably much less favorable now than they were six years ago. As a consequence, if the Mackenzie Gas Project is approved by the board it may not be built, or at least not for some time.

Land claim disputes

Natural gas production forecasts are also at risk when governments and aboriginal groups cannot agree on the ownership of the resource. For example, even if the existing *de facto* federal government moratorium on exploratory drilling in Queen Charlotte Sound in British Colombia were removed, there could be no progress until the disagreement among the first nations and the federal and provincial governments as to who owns the offshore natural gas resource is resolved.

Land access

With conventional oil and gas production, petroleum operators have often had problems obtaining landowners' permission to access their lands for exploration and production drilling. Most jurisdictions have put in place regulatory processes and procedures to deal with this issue. However, in some areas, the number of disputes requiring resolution by regulatory bodies is growing, adding to the time and cost required to gain access, and indicating that institutional reforms may be required.[21]

With the development of unconventional sources of gas, such as CBM and gas from shale formations, land access is also becoming an issue in regions where it has not been hitherto because, previously, there was little or no upstream petroleum industry activity. In some cases, as with CBM, increased density of exploration and production drilling requirements may also exacerbate landowner resistance. If land access issues are not resolved, natural gas investment and production will be constrained in some areas.

Constraints on Mexico's capacity to mobilize capital and expertise

Reforms that Mexico made in 2008 will allow foreign companies to explore for oil and gas in that country as subcontractors of state-owned PEMEX. However, because the companies cannot own, and therefore have commercial control over, the natural gas that they discover, they are unlikely to shift their attention from more rewarding opportunities elsewhere. For this reason, the capital and expertise required to trigger the turnaround in oil and associated natural gas production, and the increase in production of natural gas not associated with oil (eg., in the Burgos and Sabinas Basins) that the Mexican government is anticipating may not be achievable.

Risk of interruption in liquefied natural gas (LNG) imports

The US gas market imported a record 771 Bcf of LNG in 2007. However, volumes have fallen since then due to the increase in US gas production from shale formations and weaker gas demand because of the recession. In 2008 and 2009, LNG imports were sharply lower, at 352 Bcf and 452 Bcf respectively (Energy Information Administration, 2010f).

The main US LNG consumers are located in regions accessible from import terminals in New Brunswick, along the US Atlantic Coast, in the US Gulf of Mexico, and

21 The 2009 annual report of the Alberta Surface Rights Board shows a four-fold increase since 1999 in the number of applications that the board receives with respect to right-of-entry and compensation reviews (Alberta Surface Rights Board, 2010). Not all of the increase pertains to the Alberta oil and gas industry. However, review of information in earlier annual reports and information provided by Surface Rights Board staff confirm that the number of Alberta oil and gas industry disputes has increased substantially during the past decade.

on Mexico's northern Baja California coast. Disruptions in LNG shipments to Canada, the US and Mexico, whether because of severe storms, accidents, or some other reason, could lead to supply shortages that affect electric power generation and industrial and commercial activity. Although no disruptions are anticipated, and the volume of US LNG imports is not expected to increase much during the next 20 years because of competition from growing unconventional gas supplies and the more favourable price-cost differentials on LNG shipments to Europe and Southeast Asia, the possibility of a supply disruption is nonetheless an ongoing risk.[22]

Environmental constraints on shale gas recovery

There has been considerable fanfare over the newfound potential for the production of gas from shale formations as the result of technological advances and increasing experience in horizontal drilling and multi-zone hydraulic fracturing techniques. However, in some regions (New York and Pennsylvania, for instance) public pressure has been mounting to curb the extent and pace of development of shale gas resources because of concern over the impact on local water supplies and other environmental issues. For this reason, gas production from shale formations may grow more slowly than the US Energy Information Administration is currently anticipating.

In spite of the uncertainties surrounding the natural gas production forecasts, the larger size of the continent's potential gas resources from continuing delineation of shale gas formations suggests that North American gas production could increase beyond the levels indicated in the reported forecasts if market conditions warrant.

At the World Energy Congress held in Montreal in September 2010, Peter Voser, CEO of Royal Dutch Shell, indicated that his company plans to vigorously develop its shale and tight gas resources in Canada and the United States (Voser, 2010). Other production companies are also caught up in what Mr. Voser refers to as the natural gas revolution resulting from the emergence of shale gas as a significant and rapidly growing element in the natural gas supply picture.

Greater gas production growth than projected by the current forecasts will increase the likelihood that continental gas consumption requirements can be met without much, if any, rise in natural gas prices. In turn, evidence of relatively low and stable prices could foster growth in the demand for gas for power generation at the expense of coal.

22 As with other natural gas delivery risks, such as those arising from pipeline fractures or production interruptions due to storms or equipment failures, the best protection available is probably that offered by adequate storage facilities.

Natural gas consumption

Figure 7 illustrates the extent to which natural gas consumption increased in Canada, the US, and Mexico from 1999 to 2009.

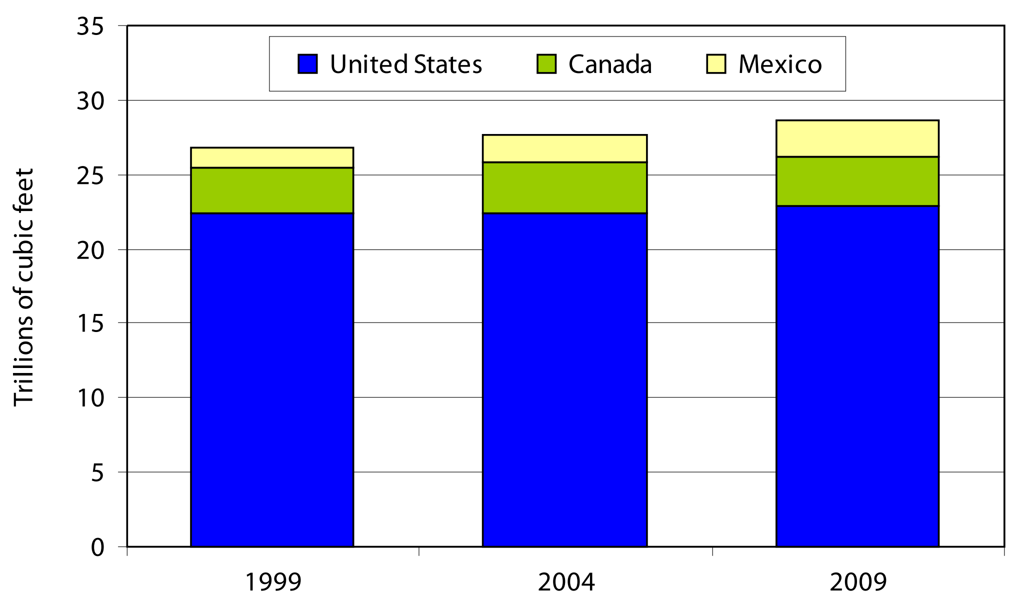
Gas consumption has been growing more rapidly in Mexico than in Canada or the US. In fact, Mexican gas use increased at a remarkable compound annual growth rate of 6.5% from 1999 to 2009. This growth was primarily from gas requirements arising from new gas-fired electric generation plants.

Canadian natural gas consumption grew at a compound annual growth rate of 0.8% from 1999 to 2009, led by growth in gas requirements for process heat at oil sand bitumen production and upgrading facilities, and by increased demand for gas for electricity generation in Alberta and other provinces.

In the United States, gas consumption increased only slightly from 1999 to 2009. The rise in natural gas prices and price expectations during much of that time caused industrial gas demand to drop. This effectively offset the increase in demand from the numerous new gas-fired electric generators that had come on stream.

As figure 7 illustrates, during the 1999 to 2009 period, Mexico's share of continental gas requirements increased by 3.7 percentage points to 8.6%, while Canada's

Figure 7: North American Natural Gas Consumption by Country, 1999–2009 (in trillions of cubic feet)



Source: British Petroleum, 2010.

Table 7: Natural Gas Consumption, by Country, 2010–2030 (in trillions of cubic feet)

Region	2010	2015	2020	2030
Canada	3.22	3.65	3.77	4.03
Mexico	2.46	2.50	3.10	4.60
United States	22.51	21.74	22.63	24.33
North America	28.19	27.89	29.50	32.96

Sources: Energy Information Administration, 2010a, table 13, and 2010d, table A6; National Energy Board, 2009a, figure 6.5; and author's extrapolations

share rose only slightly, by 0.2 percentage points, to 11.7%. At the same time, the US share dropped to 79.7% from 83.6%, a decrease of 3.8 percentage points.

In North America as a whole, natural gas consumption reached 28.6 Tcf in 2009 compared with 26.8 Tcf in 2000. US gas requirements totaled 22.8 Tcf in 2009 compared with Canadian gas consumption of 3.3 Tcf and Mexican gas consumption of 2.5 Tcf.

Table 7 summarizes North American natural gas consumption projections to 2030. North American gas consumption is projected to grow at a compound annual rate of 0.8% from 2010 to 2030. Demand is anticipated to be the most robust in Mexico, with a compound annual growth rate 3.2%, largely driven by increased use of natural gas for power generation.

For Canada, extrapolation of the National Energy Board's gas consumption projection from 2020 to 2030 assumes that the compound annual growth rate of 0.7% implicit in the board's projection for the 2015 to 2020 period continues. Increased gas requirements will likely be driven by demand from oil sands production and power generation. The Energy Information Administration's US forecast points to slow growth in gas consumption (a compound annual growth rate of only 0.4%) from 2010 to 2030.

The projections of natural gas consumption growth to 2030 in the International Energy Agency's *World Energy Outlook* 2009 reference case for Canada and Mexico are similar to those indicated in table 7, both exhibiting strong increases for the reasons mentioned earlier (International Energy Agency, 2009, table 10.1: 360). In the International Energy Agency's projection, US gas consumption drops from 2007 to 2015. It then recovers somewhat, but is still below its 2007 level in 2030.

Natural gas consumption uncertainties

The projections of natural gas consumption are subject to a number of uncertainties. The following are among the more important:

Natural gas price

The demand for gas is price sensitive, particularly in the case of major institutional and large industrial consumers who are able to switch between fuel oil and natural gas to some extent. For every possible assumed gas price configuration there is a different regional, national, and continental gas demand configuration. Not knowing how natural gas prices will track in the future makes it difficult to predict gas consumption with much accuracy.

Economic growth

Another important determinant of natural gas demand is the rate of economic growth. The sensitivity of gas demand to the rate of economic growth can be seen by comparing the natural gas consumption estimates in the Energy Information Administration's 2010 *Annual Energy Outlook* high and low US economic growth case projections. Assuming a high average annual GDP growth rate of 3.0% instead of a low average annual GDP growth rate of 1.8%, yields a difference of 4 Tcf or 18% in the volume of natural gas consumption between the two cases in 2030 (Energy Information Administration, 2010a). The stronger the rate of economic growth, the stronger natural gas demand. Not knowing how strong (or weak) economic growth will be increases the difficulty of forecasting gas consumption.

The International Energy Agency's 2009 World Energy Outlook reference case assumes an average annual growth rate of US real GDP from 2007 to 2030 of 2.0%. This compares with a 2.4% GDP growth rate assumption in the US Energy Information Administration's 2010 *Annual Energy Outlook*. Differences in the economic growth rate assumption make it difficult to compare projections prepared by different agencies. The sensitivity of gas demand to economic growth also underscores the uncertain nature of natural gas consumption growth estimates.

Technological change

Other things equal, technological changes that improve the efficiency of natural gas appliances, such as gas furnaces and water heaters, cause natural gas requirements to drop. Technological developments that lead to viable substitutes for natural gas will also lower gas consumption and constrain or even offset the growth in consumption that one would expect from economic and population growth. Other technological changes, such as those leading to the commercialization of fuel cells, will increase natural gas consumption. Without knowing how technological improvements will evolve, it is difficult to project gas requirements with precision.[23]

Natural gas requirements for electricity generation

Another element of uncertainty in the North American natural gas consumption outlook is how much natural gas will be required for electricity generation.

Table 8 summarizes the extent to which the Energy Information Agency and the National Energy Board expect natural gas to be relied upon for electricity generation in each of the three countries and for all of North America from 2007 to 2030.[24]

Table 8: Electricity Generated from Natural Gas (in thousands of gigawatt hours)

	US	Canada	Mexico
2007	897.0	53.6	90.0
2020	767.0	82.7	173.0
2030	1,015.0	n.a.	300.0

Sources: Energy Information Administration, 2010d, table H13; National Energy Board, 2009a, Appendix table 5.4.

23 This discussion is not intended to infer that forecasts of natural gas consumption are generally so inaccurate that they can be of little use. Natural gas consumption forecasts are conditional upon specific sets of assumptions. While such forecasts can't be expected to be very accurate, as indicators of how gas requirements will unfold in the future they can and do assist the energy policy makers.

24 Approximately 3.32 mcf (million cubic feet) of natural gas is required to generate one megawatt hour of electricity. The precise amount mainly depends on the efficiency of the generator.

In 2007, 21.6% of US electricity generation came from natural gas combustion compared with 37% in Mexico and only 9% in Canada (Energy Information Administration, 2010d, tables H11 and H13; National Energy Board, 2009, appendix table 54).

The US Energy Information Administration is projecting that the natural-gas-fired share of electricity generation in the US will fall slightly, to 20.3%, by 2030. The nuclear power share of total US electricity generation is projected to decline by almost 2 percentage points, while the coal share is projected to drop from 48% in 2007 to 44% in 2030. The declines in the nuclear, coal, and gas shares are attributable to a significant gain in the share of electricity generation that is projected to come from renewable energy sources, especially wind. While US electricity generation from natural gas increases after 2014, it does not return to 2008-2009 levels until after 2025.

In Mexico, the natural-gas-fired share of electricity generation is projected to increase sharply, to about 61% (Energy Information Administration, 2010d). This assumes that Mexico will meet a 202% increase in electricity demand (from 2007) almost entirely by adding natural-gas-fired electric generation capacity.

The National Energy Board is projecting that the share of natural-gas-fired electricity generation in Canada will reach 12% by 2020 (National Energy Board, 2009a). The board anticipates increased reliance on both natural gas and nuclear power due to a declining preference for coal.

Note that the forecasts are all essentially "business as usual" cases. Were curbs to be imposed on carbon dioxide emissions, power generation from coal would likely become much more expensive because of the carbon penalty. This would push decision makers, whether governments, public utilities, or private investors, towards power generation technologies with lower, more competitive long-run marginal costs. These would include nuclear power and onshore wind, but natural-gas-fired electricity would also benefit because it would not be hit nearly so hard as coal-fired generation (International Energy Agency, 2009: 382). Uncertainty about carbon emission abatement policy in power generation applications clearly compounds the difficulty of forecasting natural gas power consumption.[25]

Environmental policy changes

Forecasting natural gas consumption is subject to further uncertainty because of environmental policy changes that are being touted to reduce greenhouse gas emissions, a purported contributor to climate change. The imposition of carbon taxes and low carbon fuel standards, for example, will affect the volume and type of fuels derived from

25 In 2008, gas used for power generation represented 31% of the natural gas volumes delivered to US gas customers (US Energy Information Administration, 2010i).

crude oil and natural gas that are consumed. Not only are the full extent and timing of proposed market interventions along these lines unknown, but little historical experience and data are available to guide forecasters charged with assessing the impacts of such changes on natural gas consumption.

Uncertainties in perspective

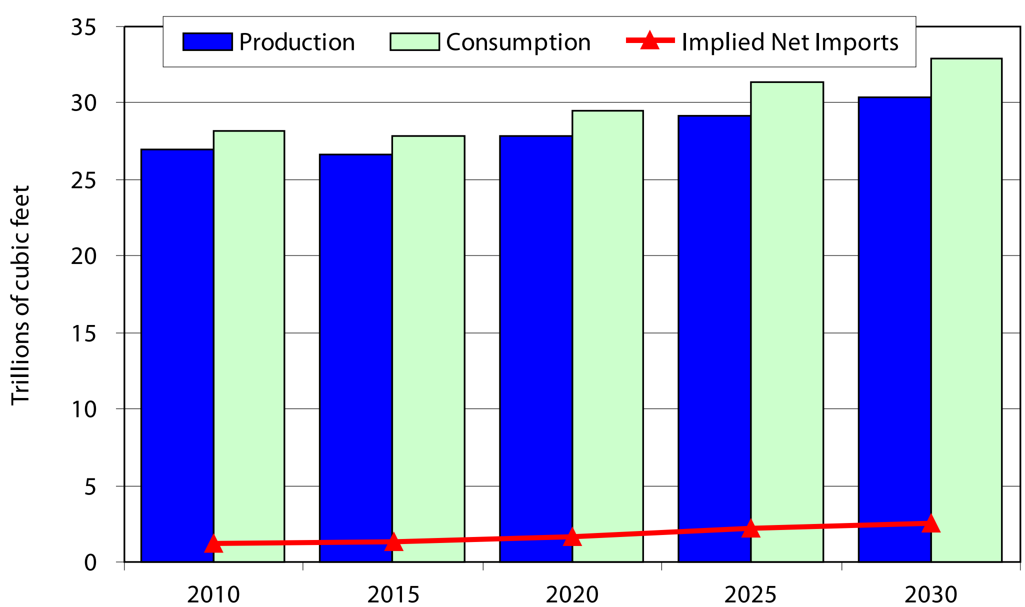
Given the uncertainties with respect to the factors that determine gas demand, considerable care must be taken when comparing different forecasts because of the different model structures and assumptions underlying the various projections. A particular long-term projection of natural gas consumption is very unlikely to turn out to be correct, especially for times further in the future, because of the number of variables involved. However, the Energy Information Administration and National Energy Board forecasts examined in this paper generally provide reasonable indications of how North American natural gas consumption is likely to evolve.

Considering the projections of natural gas production and consumption discussed above, and the uncertainties associated with the forecasts, there is a possibility that North America could become more dependent on LNG imports during the next 2 decades than is implied by those projections if investment in the expansion of domestic gas production is frustrated by non-market barriers. However, as mentioned in the discussion of the outlook for gas production, primarily because recent advances in technology have lowered the cost of shale gas production, the continent appears to have the potential to support an increase in gas production beyond the levels indicated in the reported forecasts. The possibility of continued production growth more or less in step with growth in the continent's gas requirements, and therefore relatively low gas prices compared with the experience earlier in this decade, could open the door to significant gains in gas demand growth for power generation. This is likely for two reasons: evidence that an era of stable gas prices is at hand; and lower greenhouse gas emissions with natural gas than with coal. The main challenge for policy makers will be to ensure that obstacles that stand in the way of gas production development that could compete with imported LNG are removed.

National and continental natural gas production and consumption relationships

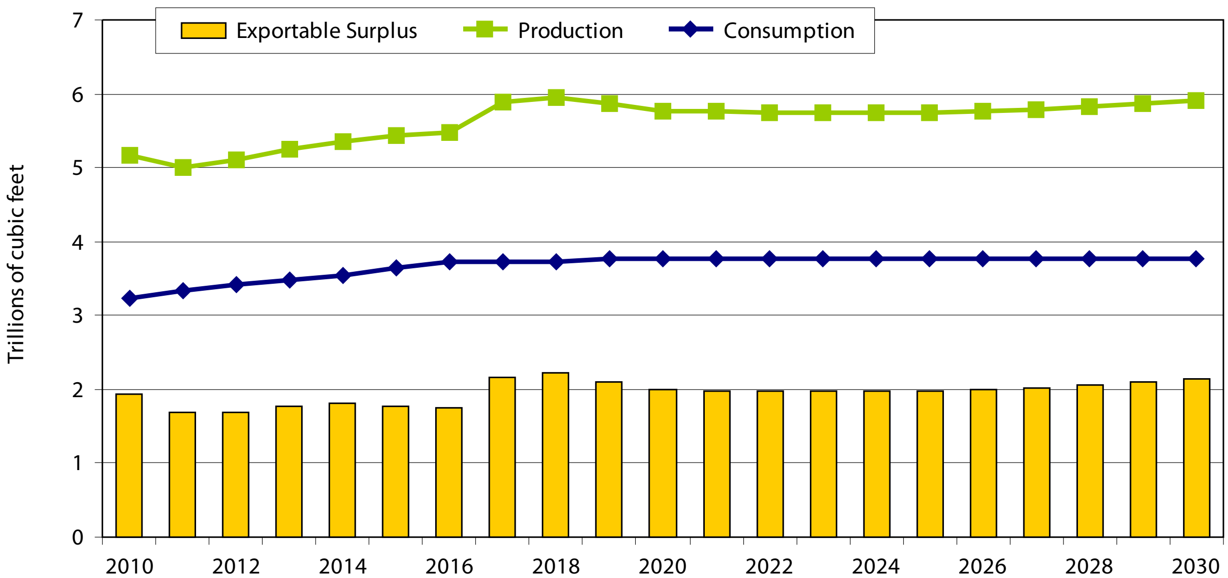
North American natural gas consumption is currently greater than domestic production. This situation is expected to continue according to the production and consumption forecasts presented earlier. However, as figure 8 illustrates, the shortfall in North American gas production relative to consumption is not likely to increase very much during the next 20 years, according to the projections by the respective government agencies. As the following discussion indicates, the anticipated increase in the shortfall is due to developments in Canada and Mexico rather than in the United States where the shortfall in gas production relative to consumption is projected to shrink during the next 20 years as the result of increased shale gas production more than offsetting declines in conventional gas production in the lower 48 states.

Figure 8: North American Natural Gas Production versus Consumption, 2010–2030 (in trillions of cubic feet)



Sources: Energy Information Administration, 2010a and 2010d; National Energy Board, 2009a, and Fraser Institute author calculations.

Figure 9: Canadian Natural Gas Production vs. Consumption, 2010–2030 (in trillions of cubic feet)



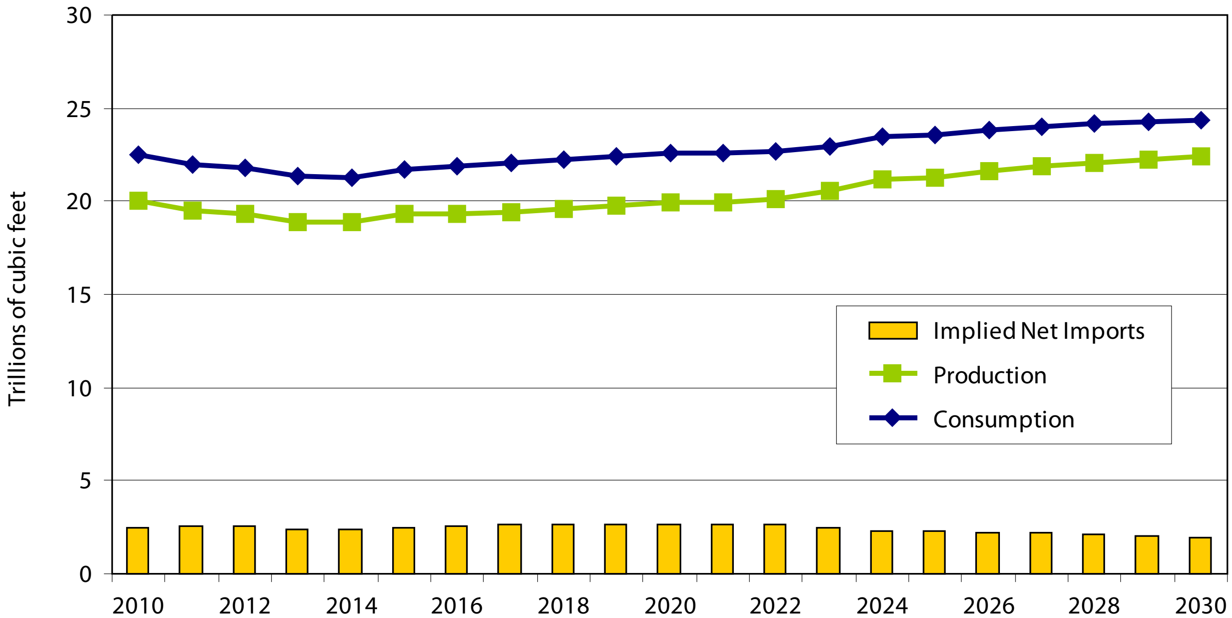
Source: National Energy Board, 2009a, figures 6.2 and 6.5.

Canada is the only one of the three countries where domestic gas production is expected to exceed consumption during the forecast period. As figure 9 shows, the National Energy Board expects that Canadian gas production will continue to exceed consumption in 2020, the final year in its most recent forecast (National Energy Board, 2009a). By then, annual Canadian production is projected to be about 5.8 Tcf—or about 0.6 Tcf less than in 2002 when production reached its highest point since the turn of the century.

Unconventional Canadian gas production will likely continue to increase from 2020 to 2030. However, due to the assumptions that were made regarding the various categories of production for the purpose of extrapolating the National Energy Board's natural gas production forecast to 2030, total Canadian gas production in that year is projected to only reach 5.9 Tcf. The small (0.1 Tcf) increase is the result of the continuing slide in conventional gas production from the Western Canada Sedimentary Basin because of production decline rates in maturing fields and the inability to bring on sufficient production from new wells.

The National Energy Board's reference case projection to 2020 shows Canadian gas consumption increasing at an annual rate of almost 1.6% from 2010 to 2020 (National Energy Board, 2009a). For the purpose of this study, we have assumed that the compound annual growth rate of Canadian gas consumption in the board's fore-

Figure 10: US Natural Gas Production versus Consumption, 2010-2030 (in trillions of cubic feet)



Source: Energy information Administration, 2010a, table 13.

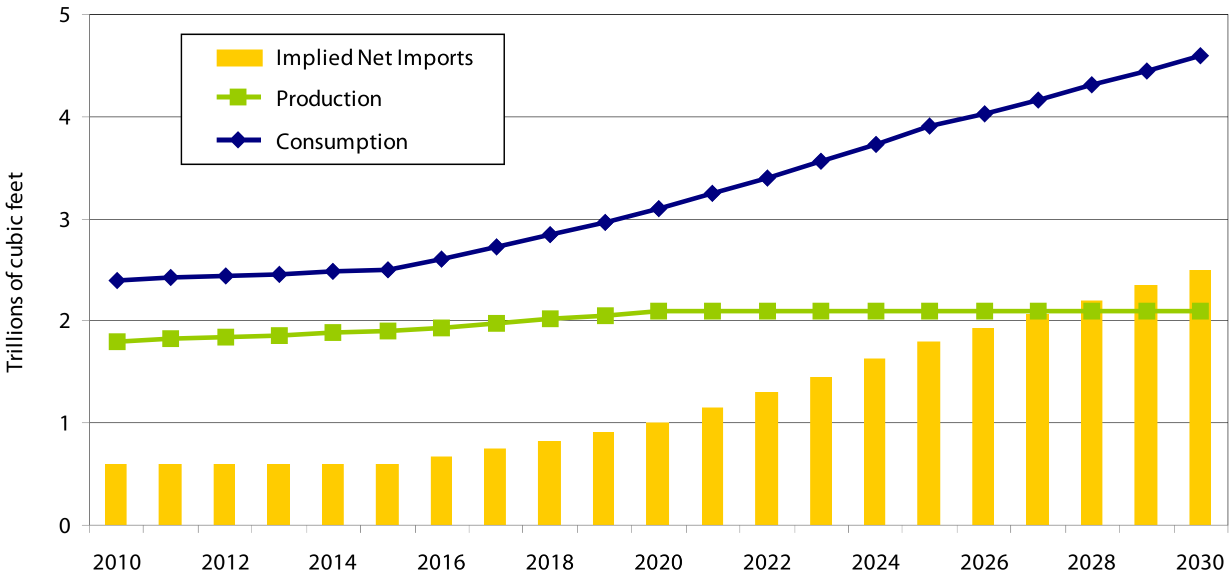
cast for 2015 to 2020, 0.65%, will continue to 2030. If this were the case, in 2030 projected Canadian gas production would exceed domestic consumption by nearly 1.9 Tcf. That is, Canada would still have a considerably sized exportable surplus and be in a position to continue as a significant net exporter of natural gas to the United States throughout the forecast period.

Figure 10 illustrates the projected relationship between US domestic natural gas production and consumption during the period to 2030.

The US Energy Information Administration's projections show domestic gas production beginning to catch up with US gas consumption by the end of the forecast period. Gas supply growth facilitated by construction of the Alaska pipeline and the lifting of moratoria on offshore exploration and production helps to offset declining production from mature conventional wells in the US lower 48 states. Unconventional natural gas supplies (such as gas from shale formations and coalbed methane) will also contribute to a reduction in the domestic supply shortfall.

The gap between US gas consumption requirements and domestic gas production in 2030 of slightly less than 2 Tcf is much smaller than that indicated in the Energy Information Administration's 2007 *Annual Energy Outlook*. It predicted that US net LNG imports of 4.5 Tcf would be required by 2030 (Energy Information Administra-

Figure 11: Mexican Natural Gas Production versus Consumption, 2010-2030 (in trillions of cubic feet)



Source: Energy Information Administration, 2010d, tables A6 and I1.

tion, 2007). Although some industrial gas demand was lost when gas prices spiked during the early years of this decade and, more recently, because of the 2008/2009 recession, the main reason for the improved outlook is that US unconventional gas production capacity has benefited from important technological advances during the past few years. In fact, with a free market policy framework and further technological advances, domestic gas production will likely be able to satisfy most if not all of US gas requirements during the next two decades and well beyond.

Figure 11 illustrates the US Energy Information Administration's view that Mexico's current shortfall of production relative to consumption is likely to increase considerably from now to 2030.

According to the BP *Statistical Review of World Energy*, Mexican natural gas consumption exceeded that country's gas production by 0.4 Tcf in 2009 (BP, 2010). The Energy Information Administration is predicting that the shortfall of domestic gas production relative to consumption in Mexico could escalate to as much as 2.5 Tcf by 2030 (Energy Information Administration, 2010d, tables A6 & I1).

North American natural gas trade

As table 9 indicates, during the past 20 years North America as a whole has shifted from being a small exporter of natural gas to a significant gas importer.

Canada is the only net gas exporter among the three countries. Canadian net gas export volumes to the US (currently the sole market for Canadian gas) almost doubled from 1989 to 1994, and then increased by 32% during the following 5-year period. More recently, however, Canada's gas exports have been falling. The drop is partly a consequence of declining gas production rates in the Western Canada Sedimentary Basin (WCSB) and partly due to increasing gas demand by the oil sands industry.

The United States has been a net importer of natural gas consistently throughout the past two decades. Net US gas imports increased from 1,275 Bcf in 1989, to 3,422 Bcf in 1999, and 3,404 Bcf in 2004. More recently, flagging gas demand due to the economic recession and subsequent hesitant recovery, coupled with increased production thanks to improved unconventional gas production technologies, has reduced US gas import requirements to some extent.

Table 9: Natural Gas Net Exports (Imports) by Country, Source, and Destination (in billions of cubic feet)

Country	Destination or source	1989	1994	1999	2004	2009
Canada	US	1,301	2,513	3,329	3,212	2,571
	LNG	0.0	0.0	0.0	0.0	(35)
	Total	1,301	2,513	3,329	3,212	2,536
US	Canada	(1,301)	(2,513)	(3,329)	(3,212)	(2,571)
	Mexico	17	39	7	397	310
	LNG	9	12	(100)	(590)	(419)
	Total	(1,275)	(2,462)	(3,422)	(3,404)	(2,679)
Mexico	US	(17)	(39)	(7)	(397)	(310)
	LNG	0.0	0.0	(0.3)	(0.4)	(125)
	Total	(17)	(39)	(7)	(398)	(435)
Total		9	12	(100)	(590)	(578)

Sources: British Petroleum, 2010; Energy Information Administration, 2010f, 2010g, 2010e; National Energy Board, 2010.

Although its gas imports from Canada have dropped off a bit in recent years, the US has been able to meet its gas requirements, including growth in net gas exports to Mexico, in part through liquefied natural gas (LNG) imports. The US became a net LNG importer in 1997. In 1999, annual net imports of LNG were 100 Bcf. By 2004 they had reached 590 Bcf. Within the past 5 years, US net LNG imports have ranged from a low of 312 Bcf in 2008 to a high of 722 Bcf in 2007.

Mexico has also been a consistent net importer of natural gas throughout the past 20 years, but the country's dependence on imported gas has risen sharply during the past decade, from 17 Bcf in 1989 to 436 Bcf in 1999, as a result of the LNG import facilities put in place in Altamira and Rosarito. Mexican LNG imports reached an all-time high of 125 Bcf in 2009. A third Mexican LNG facility, currently under construction at Manzanillo, is expected to be operational by 2011 (Energy Information Administration, 2010c; Flores Quiroga, 2007).

Three LNG import facilities are currently under construction in the United States (at Sabine (Texas), Elba Island (Georgia—expansion of an existing facility), and Pascagoula (Mississippi)). None are currently under construction in Canada. In the whole of North America, 17 other LNG import facilities have been approved, but if and when they will ever be constructed is uncertain (Federal Energy Regulatory Commission, 2010a, 2010b). Canada's only LNG import facility, at Saint John, New Brunswick, commenced operations in June 2009.[26]

While US natural gas import requirements are projected to be significantly less by 2030 than at present, Mexico will increasingly find it necessary to import more gas to satisfy its growing needs unless PEMEX is able to boost production, according to the Energy Information Administration. Moreover, as mentioned, Canada's export capacity is expected to diminish because of declining conventional gas production in the Western Canada Sedimentary Basin and increasing gas requirements for oil sands applications.

Table 10 summarizes the continental natural gas trade picture and outlook. According to this scenario, North America will require about 2.6 Tcf of imported natural gas by 2030.[27] This is greater than the estimated net import requirements for 2010 by 1.4 Tcf. The increase is entirely a consequence of the outlook for Mexican gas production and consumption requirements. Because of flagging gas production there, and growing gas requirements to fuel new power plants, Mexico could require annual net gas imports of 2.5 Tcf in 2030 compared with only 0.40 Tcf in 2009. In spite of this,

26 There is one LNG export facility in North America, the Kenai LNG Export Terminal in Alaska (Federal Energy Regulatory Commission, 2010a; California Energy Commission, 2010). Another is planned for Kitimat, British Columbia (Kitimat LNG, 2010).

27 This compares with US net gas imports of 3.8 Tcf in 2007 and earlier forecasts of much greater dependence on imports, especially LNG, by 2030.

Table 10: Net Exports (Imports) of Natural Gas by Region, 2010–2030 (in trillions of cubic feet)

Region	2010	2015	2020	2030
Canada	1.95	1.78	2.00	1.90
Mexico	(0.60)	(0.60)	(1.00)	(2.50)
United States	(2.50)	(2.45)	(2.65)	(1.95)
North America	(1.15)	(1.27)	(1.65)	(2.55)

Note: Numbers here were derived from the Production vs. Demand analysis.
Sources: Energy Information Administration, 2010a, 2010d, table H13; National Energy Board, 2009a, Appendix table 5.4., and author's estimate for Canada (for 2030)

given the extent of North America's recoverable natural gas resources as examined earlier in this paper, continental self-sufficiency in natural gas appears to be within reach if barriers to investment in natural gas production development and transportation facilities in all three countries are lowered.

Barriers to natural gas development projects

US domestic natural gas production increased strongly in 2008 and the high production level was maintained in 2009 as the result of the growth in gas production from shale formations. In order to further increase the capacity to produce gas from indigenous sources, policy makers need to address the regulatory and non-market barriers that are constraining investment in North American gas production and pipeline facilities. These include the following:

Uncompetitive royalty regimes

Ideally, Canada, the United States, Mexico, and other countries, ought to move to the type of flat tax regime for both individuals and businesses described in a recent Fraser Institute study (Clemens, 2008). This approach taxes income from the sale of goods and services, minus the cost of all inputs, including wages and salaries. It thus takes the higher costs of relatively expensive projects into account and eliminates the need for royalties *per se*. In addition, subsidies on energy production of all kinds should be removed to ensure that only those energy resources that can compete are developed.

In lieu of overall tax reform of this magnitude, the tax structures facing the natural gas industry in North America, including royalties, need to be competitive with those elsewhere in the world. If they are competitive, jurisdictions in Canada, the United States, and Mexico will not be at a disadvantage in the global competition for natural gas exploration and investment.

For the most part, natural gas royalty regimes in Canada and the United States are competitive with those in other countries. However, some provinces and states tax oil and gas production to an extent that makes petroleum industry investment less compelling there than in other jurisdictions in North America and overseas.

Alberta provides a recent case study. After the provincial government announced that it intended to adopt a more onerous royalty regime, Alberta lost some petroleum exploration and development investment to the adjacent provinces of British Columbia and Saskatchewan, and to other provinces, US states such as Colorado and Montana, and other jurisdictions. This loss is outlined by respondents to the Fraser Institute's 2009 *Global Petroleum Survey* (Angevine and Cervantes, 2009). Essentially, the changes to the Alberta royalty regime under the so-called "New Royalty

Framework" that took effect January 1, 2009, caused some companies to move some or all of the Alberta portion of their upstream budgets to other jurisdictions. A University of Calgary study (Mintz, Jack and Duanjie Chen, 2010) also provided evidence that the shift to higher royalties led to the Alberta petroleum industry becoming uncompetitive with other provinces (especially British Columbia and Saskatchewan) and US states such as Texas.

On March 11, 2010, the Alberta government announced that as of the beginning of 2011 it would revert to a royalty scheme similar to that in effect prior to 2009. The decision to lower royalties indicated recognition of the fact that Alberta must compete with other jurisdictions around the world for petroleum investment. According to the 2010 *Global Petroleum Survey*, the announcement improved Alberta's relative attractiveness for petroleum exploration and development in the eyes of investors (Angevine and Cervantes, 2010).

The benefits of ensuring that natural gas royalties, production sharing requirements, and production taxes are competitive are obvious. Investors in search of the best return will gravitate to the jurisdictions they regard as most favourable. A jurisdiction that trims its royalties may initially experience a drop in royalty revenues. However, it could end up recouping such losses because of increased personal and corporate tax revenues arising from the incremental employment income and corporate revenues that are generated by the additional investment that is attracted. These kinds of fiscal offsets are discussed in some detail in the Alberta government's paper *Energizing Investment: A Framework to Improve Alberta's Natural Gas and Conventional Oil Expectations* (Alberta Government, 2010: 16).

Failure to recognize higher costs of unconventional and offshore gas supplies

Another barrier that causes would-be investors to look elsewhere is royalty and production tax regimes that fail to take into account the higher costs of producing natural gas from unconventional and offshore resources relative to conventional, onshore sources. For example, there are greater costs involved with projects in the far north because of the climatic conditions and distances involved; royalty regimes need to be adapted accordingly. Jurisdictions that fail to recognize this will find that their tax structure inhibits investment. As a consequence, both the pace and magnitude of exploration and development in such jurisdictions will suffer.

Shale gas provides another example. While shale gas well production yields may be quite high initially, they generally decline rapidly. Because production sites are often in remote locations, development costs can also be higher than with conventional gas resources. Moreover, these wells may bear substantial environmental costs because of the carbon dioxide that is mixed with the produced gas and/or the impacts of the fluids and other materials required for hydraulic fracturing on water supplies. In order to entice developers to invest, especially when prices are low, provinces or states may need to adjust their applicable royalty regimes. Further, if those regimes are relatively price insensitive, it will be in a government's best interest to revise the royalty formula to make royalties more sensitive to changes in the price of gas. Taxpayers benefit from price-sensitive royalties because they help to dampen upward and downward swings in drilling activity and employment.

Another example of the need for an innovative approach to royalties relates to the industry spending hundreds of millions of dollars on research to develop feasible technologies for producing gas from new sources, such as methyl hydrates. The potential reward from this research could be very substantial, but in the meantime, companies can make considerable outlays on the research for some years. A flat tax on net revenues (as suggested earlier) that takes legitimate research and development costs into account would allow methyl hydrate development opportunities to compete on their own merit with other, alternative natural gas investment opportunities. Not only would the development of hydrates bring economic benefits, but a greater diversity of supply and improved energy security.

Uncertainty about environmental regulatory changes

Uncertainty regarding the timing and extent of curbs on greenhouse gas emissions is creating problems for would-be investors in new power generation facilities throughout North America. Removal of the uncertainty would allow investors to determine exactly how competitive gas-fired electric generation will be versus other fossil fuels and renewable power sources. Carbon capture and storage requirements should give natural gas a considerable advantage over coal and unleash a round of investment in combined cycle gas-fired electric generation capacity. However, such investment and resulting employment, income, and general economic benefits will not emerge until investors in new power plants, for example, know more precisely what the new cost structures will look like.

Since pipeline compressors use considerable amounts of natural gas, pipeline tolls and tariffs will be affected by the cost of emissions abatement facilities. For this reason, both investors in possible new gas pipeline facilities and potential shippers on such pipelines are also anxious to learn the extent of new emissions policies.

Similarly, uncertainties need to be removed in New York, Quebec, and other jurisdictions regarding possible new regulations on shale gas production. If such regulations are going to be imposed, it is important that they be defined as soon as possible so that potential investors can determine the extra costs that would be involved.

Moratoria on offshore exploration and development

Moratoria on offshore exploration in, for example, British Columbia's Queen Charlotte Basin and the US Pacific offshore, are another obstacle to investment that is inhibiting the growth of North American natural gas production. Investors previously interested in such areas may no longer be interested if and when the door is eventually opened.[28]

A report by a scientific task force appointed by British Columbia Premier Gordon Campbell in 2002 indicates that there appears to be no reason to hold back exploration on the west coast for environmental reasons. The panel concluded that the moratoria on hydrocarbon exploration and development on British Columbia's offshore could be ended responsibly, assuming that appropriate safeguards and assessments of any proposals brought forward were in put place (British Columbia Ministry of Energy Mines and Petroleum Resources, 2002). Further, the accords between the federal government and Nova Scotia and Newfoundland and Labrador appear to effectively address environmental concerns about offshore exploration and production in the Atlantic region, which begs the question why similar agreements cannot be worked out for the Pacific offshore.[29]

Factors delaying construction of gas pipelines and other infrastructure

Regulatory processes and procedures

When the National Energy Board reaches a decision in December 2010 or early in 2011 about the Mackenzie Gas Project, more than 6 years will have elapsed since October 2004 when Imperial Oil Resources Ventures Ltd. and the other project proponents filed their application for a construction permit. Although this is an exceptional case, it serves to illustrate how costly the regulatory process can be. It is unlikely that the Mackenzie Valley Gas Pipeline and the related natural gas gathering system (col-

28 In regions where moratoria have been lifted (as in the case of the US Gulf of Mexico where the six-month moratorium on deepwater exploration put in place in May 2010 has been removed), more aggressive government regulations and red tape may make investment unattractive relative to competing offshore jurisdictions.

29 The failure of automatic flow shut-off controls to activate when the rig at the BP Deepwater Horizon site in the US Gulf of Mexico exploded in April 2010, causing hundreds of thousands of barrels of crude oil to leak into the Gulf, will make it more difficult to sway those who argue that risks to the environment from offshore drilling cannot be adequately controlled.

lectively referred to as the "Mackenzie Gas Project") could now be built and put into service before the fall of 2018. This assumes that 3 to 4 years would be required to finalize construction planning and to meet the many conditions that the regulator is expected to impose on the project developers as a consequence of the recommendations put forward by the Joint Review Panel and the directions received from the federal government and the Northwest Territories with regard those recommendations (Joint Review Panel for the Mackenzie Gas Project, 2009). The timeline also assumes that in spite of much higher costs than those estimated in 2004, the project proponents will decide to proceed. Those who invested millions of dollars to explore for natural gas in Canada's far north, believing that the Mackenzie Gas Project would be built within a reasonable time frame, are clearly faced with unforeseen financial costs and an uncertain future.

As with the Mackenzie Gas Project, unnecessary delays in construction can markedly increase the capital cost of any pipeline because of wage and materials cost inflation during the extra months or years required to gain the necessary approvals.[30] In turn, this will result in generally higher transportation costs since pipeline tariffs are based on the cost of service, including depreciation and interest. Higher transportation costs impinge upon the marketability of marginal sources of supply, as with gas from the far north, which is already saddled with a transportation cost penalty because of the sheer distances involved.

Environmental approvals

The requirement that proponents of major pipeline projects file environmental impact assessments is reasonable. But when a tribunal takes years instead of a reasonable number of months to complete and table its review, as was the case with the Joint Review Panel that had as its mandate to undertake an environmental assessment of the Mackenzie Gas Project, inflation during the waiting period can push project costs up significantly.

Native land claims

Uncertainty over land claims, or demands for project equity participation by aboriginal groups without any upfront investment being required from them, can have the same unfortunate consequences for pipeline and other energy project developments as delays in the regulatory process. Settlement negotiation delays add to capital costs

30 Judging from various comments reported by the media, it appears that the capital cost of the Mackenzie Gas Pipeline has more than tripled since the application was filed in October 2004. Costs may have dropped a bit recently because of the economic downturn, but the actual cost of construction will undoubtedly be much higher than the original estimate.

because of inflation and because they push up the transportation tolls or tariffs. The cost of the settlement itself further inflates the cost.

Land access compensation

Disputes between landowners (other than first nations groups) and pipeline proponents over the compensation that the owners must be paid for access to land may also result in undue delays.

Constraints on foreign investment

Laws and regulations that forbid foreign investors from sharing in the risks and rewards from the discovery, development, and production of natural gas resources will slow production growth unless sufficient domestic capital and expertise are available. This is the case in Mexico, which nationalized the petroleum industry, causing foreign-owned companies to leave the country in 1938.

In 2008, the Mexican government introduced a number of reforms designed to increase petroleum production (Mueller et al., 2008). The changes allow PEMEX to contract domestic and foreign drilling companies to assist in oil and gas exploration and production. PEMEX can relate the company's contractual obligations to performance, including productivity. Unfortunately, the incentive arrangements that PEMEX is offering to subcontractors fall well short of creating a truly free market in Mexico's upstream petroleum market, including opportunities for foreign investment in petroleum exploration and development.

Policy recommendations

The North American natural gas supply and demand outlook, together with the extent of the continent's recoverable gas resources, indicates that there is considerable potential to grow the continent's natural gas production capacity. However, for our citizens to reap the employment, income, and economic growth benefits from such development, Canada, the United States, and Mexico need to revise their relevant policy frameworks to lower the regulatory and other non-market barriers that impede the necessary investment.

Specific natural gas policy recommendations include the following:

1. *Ensure that natural gas royalty regimes throughout North America are globally competitive*
   In some cases, the respective federal, state, and provincial governments may find that their royalty regimes are no longer competitive, not only within North America but compared with jurisdictions in Europe, Australia, and elsewhere overseas. A universal, flat, net revenue tax regime would enable the elimination of royalties. In lieu of such widespread reform, some jurisdictions will need to alter their royalty rates if they wish to be competitive.

2. *Reflect in royalties the higher costs of producing gas from unconventional sources*
   Governments must be mindful of the differences in the cost structures between conventional natural gas production on the one hand, and production from unconventional and frontier sources of supply, such as coalbed methane, tight sands, shale formations, the deepwater outer-continental shelf, and the northern frontier, on the other.

   The ideal solution to the problem of varying costs depending on the source of natural gas supply is an across-the-board, flat net revenue tax. However, in the absence of overall tax reform, policy makers need to review and adjust the royalties applicable to unconventional, offshore, and frontier natural gas supplies to ensure that they are competitive.

3. *Reduce uncertainty surrounding environmental policy changes*
   It is essential to remove the cloud of uncertainty that is hanging over the gas industry and major industrial gas consumers, including power generators, because of the potential cost of compliance with the anticipated more stringent carbon emissions regulations. For this reason, provincial, state, and federal governments need to determine and implement as soon as possible any new environmental regulations related to greenhouse gas emissions reductions that affect natural gas production, processing facilities, and pipelines.

4. *Remove barriers to offshore development*
   Moratoria on petroleum exploration and production in offshore areas, such as in the Queen Charlotte Basin and the US Pacific offshore, should be lifted once the authorities are satisfied, having examined the cause of the BP Deepwater Horizon crude oil leak in the US Gulf of Mexico, that the environmental risks can be mitigated.

   The lifting of moratoria on offshore exploration will open new areas for potential discoveries and allow additional indigenous natural gas supplies to be tapped if the exploration is successful. At a minimum, the local communities and the jurisdictions directly involved will benefit from the employment and income generated by the exploration activity. Assuming that commercially viable natural gas resources are discovered, the subsequent investment in gas production, processing, and transportation facilities will generate additional employment and income in the affected regions, and will also contribute more broadly to economic growth. Increased supplies of domestic gas will benefit gas consumers by improving energy supply security.

5. *Streamline regulatory processes pertaining to pipeline construction permits*
   Additional pipeline capacity will be needed to transport natural gas to market hubs from the shale formations that are being developed throughout North America and from new LNG terminals. Related regulatory processes and procedures for obtaining construction permits need to be reviewed to ensure that unnecessary obstacles are not allowed to stand in the way of project construction. This may require more than simply tightening the self-imposed service standards that regulators have for the schedules they use for reaching decisions. In some cases, legislation governing regulators' scope, procedures, and processes may require extensive revamping to speed up decision making. Certainly, energy policy must ensure that production capacity development is not blocked or slowed because of failure to put new transportation infrastructure in place as quickly as required.

   Ensuring that regulatory processes and procedural roadblocks (as witnessed in the Mackenzie Gas Project debacle) are removed will allow projects to be approved more readily and therefore at less cost to both government regulatory bodies and the developers. More timely construction will keep project costs from being hit by wage and material cost inflation during the "extra" time that the regulators would have otherwise required. The lower capital costs should, in turn, result in lower transportation costs because of lower tolls and tariffs for transportation service on the pipeline in question. Ultimately, gas consumers should benefit from lower delivery charges on their monthly gas bills than if the regulatory process were protracted.

6. *Develop more efficient yet fair procedures for resolving native land claims*
   Demands by native groups can pose serious roadblocks to the approval and construction of new pipelines on lands to which they claim to have property rights. Approaches for settling native land claims issues expeditiously and in a fair and appropriate

manner need to be found in order to help to prevent such claims from delaying pipeline construction and saddling eventual users with inappropriately high transportation costs.[31]

The more quickly settlements can be reached and native workers can be engaged in project construction, the greater the economic and social benefits to native communities. The regional and provincial economies will also benefit, indirectly, from project construction expenditures. Moreover, through the "induced" effects that come when construction workers spend their wages, employment and income benefits will be spread to other communities and provinces.

7. *Defuse and prevent disputes over the conditions by which petroleum operators have access to land*

Policy makers must find means, where they are not already in place, to prevent the development delays that occur when disputes arise over the compensation that is paid to landowners for access to their land—whether by petroleum operators for exploration or operations, or by developers seeking to build gas transmission pipelines. Dispute resolution mechanisms must, of course, ensure that landowners are consistently treated fairly.

Disagreements over land access threaten to stymie the development of gas production from shale formations in jurisdictions that have not experienced much, if any, natural gas exploration or production activity in the past. These jurisdictions do not have appropriate institutional arrangements in place to resolve disputes between petroleum operators and land owners. It is important that such states, provinces, and countries establish appropriate protocols as quickly as possibly, based on best practices and the experiences of other areas that have already had to deal with the issue.

Some jurisdictions that do have established upstream oil and gas industries are nonetheless experiencing land access issues. They should review the arrangements and practices that are in place and working well in other jurisdictions. They can then adapt for themselves proven approaches that will reduce the frequency and duration of disputes, while ensuring that landowners receive fair compensation for the loss of use of their land while also allowing for access by petroleum operators.

Where disputes over the settlements being offered arise frequently, or are prolonged because of mistrust of petroleum operators and project developers, the results of recently negotiated settlements in the region should be made publicly available, as they are in real estate transactions. Doing so would enable landowners to see for themselves the details of recent settlements in their own and adjacent regions. Improve-

31 As in the Mackenzie Gas Project case, some pipeline proponents have offered native groups an equity position in the proposed pipeline to win their support.

ments in the quantity and quality of information that is available would help speed up the negotiating process and lead to fewer cases being referred to public tribunals.

Fewer and less protracted disputes will allow the development of natural gas production, storage, and transportation facilities to proceed with fewer impediments. This will benefit people in the communities affected through increased employment and higher labor and family income.

8. *Remove constraints on foreign investment in Mexican natural gas exploration and development*

Development and production of Mexico's natural gas reserves is severely hampered by the inability of foreign petroleum companies to participate, other than via subcontracts awarded by PEMEX. A much needed influx of capital and expertise would occur if foreign companies were allowed to explore for natural gas in Mexico, to develop and operate production facilities there, and to market gas in the country, subject to market conditions and a globally competitive royalty structure and taxation framework (or, preferably a flat tax mechanism).

These changes would allow Mexico to increase gas production and enable its citizens to reap the employment, income, and general economic benefits that would come from more rapid development of the country's natural gas resources. Mexican gas consumers would also benefit from improved natural gas supply security. Further, they might pay lower prices if they could avoid the transportation cost associated with importing gas from the United States or LNG from overseas.

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