GLOBAL SUSTAINABILITY RESEARCH INC.

BC LNG

A Reality Check

David Hughes

1/17/2014

Table of Contents

Tables

Figures

Abstract

The BC Government has stated that Liquefied Natural Gas (LNG) exports will create a $100 billion dollar “Prosperity Fund” and eliminate the Provincial debt by 2028. Despite current Canadian gas production of just 12.7 billion cubic feet per day (bcf/d), the National Energy Board (NEB) has approved LNG exports from BC of 14.6 bcf/d, with a further 3.4 bcf/d under review.

An analysis of gas production fundamentals in BC reveals that meeting the NEB export approvals would require drilling nearly 50,000 new wells in the next 27 years (double the approximately 25,000 wells drilled in BC since the 1950s). Given the steep production declines associated with shale- and tight-gas, drilling rates of more than 3,000 new wells per year would be required to ramp up production to required export levels, followed by nearly 2000 wells per year to maintain production. Notwithstanding the other well publicized environmental issues with hydraulic fracturing (fracking), which would be the principal completion technology used to produce this gas, water consumption alone during the ramp up phase would exceed that of the City of Calgary, which has more than a million people.

The NEB’s forecasts of gas production in BC through 2035 do not come close to the levels needed for its LNG export approvals. Its reference case forecast for BC is the production of 57 trillion cubic feet (tcf) by 2035, yet 120 tcf are required to meet its approvals (more than three times BC gas reserves). Furthermore, the NEB projects gas production to fall in all provinces except BC through 2035. As Canada’s energy regulator, with a responsibility for ensuring adequate future gas supplies for Canadians, the NEB does not appear to be meeting its mandate. It is uncertain how much of the approved export capacity will be built, but the public would be well advised not to count on an LNG bonanza.

BC LNG: A Reality Check[1]

David Hughes
Global Sustainability Research Inc.

Introduction

Over the past couple of years we have heard a lot of rhetoric from the BC government and industry about liquefied natural gas (LNG) exports.[2] The National Energy Board (NEB) has approved seven LNG export applications and two others are pending review. We are led to believe that LNG is a potential bonanza on the scale of the oil sands capable of creating a $100 billion “Prosperity Fund”, and wiping out the province’s debt by 2028.[3] An analysis of gas production in BC and the characteristics of the shale- and tight-gas reservoirs targeted, as well as the environmental issues surrounding scaling production to the levels envisioned, suggests these lofty plans bear closer scrutiny.

NEB Approvals

Table 1 lists the NEB’s approved and pending LNG export projects for BC’s west coast.[4] Approved projects total 14.6 billion cubic feet per day (bcf/d) with an additional 3.4 bcf/d of projects under review. To put this in perspective, Canada’s total production in the latest month for which figures are available was 12.7 bcf/d, according to the NEB. Three other projects reported by the BC government have not yet been submitted to NEB for export approval.

Project	Period	BCF/Day	Date Approved	Location	Owners
KM LNG Operating General Partnership	20 yr	1.28	Oct-11	Kitimat	Apache Canada Ltd. (50%); Chevron Canada Ltd. (50%)
BC LNG Export Co-operative LLC	20 yr	0.23	Feb-12	Kitimat	Complex set of companies which include the Haisla First Nation under "Douglas Channel Energy Partners"
LNG Canada Development Inc.	25 yr	3.23	Feb-13	Kitimat	Shell Canada, KOGAS (Korea), Mitsubishi Corporation (Japan) and PetroChina Company Ltd
Pacific NorthWest LNG Ltd.	25 yr	2.74	Dec-13	Lelu Island Prince Rupert	Petronus (Malaysia); Japex (10%); PetroleumBRUNEI (minority)
WCC LNG Ltd.	25 yr	4.00	Dec-13	Kitimat or Prince Rupert	ExxonMobil Canada Ltd. (50%) and Imperial Oil Resources Ltd. (50%)
Prince Rupert LNG Exports Limited	25 yr	2.91	Dec-13	Ridley Island Prince Rupert	BG Group (UK)(100%)
Woodfibre LNG Export Pte. Ltd.	25 yr	0.29	Dec-13	Squamish	Woodfibre LNG Export Pte. Ltd. (Singapore)(100%)
Triton LNG Limited Partnership	25 yr	0.32	Under Review	Kitimat or Prince Rupert	AltaGas Ltd. (50%); Idemitsu Canada Corp (Japan)(50%)
Aurora Liquefied Natural Gas Ltd.	25 yr	3.12	Under Review	Prince Rupert, Grassy Point	CNOOC Ltd. (Nexen - China); INPEX Corp. (Japan - minority); JGC Corp. (Japan engineering company - minority)

Table 1 – LNG export applications approved or under review by the NEB. Approved applications total 14.6 bcf/d with an additional 3.4 bcf/d under review.

The NEB's role as Canada's energy regulator is to determine, among other things, if exports are surplus to Canadian needs. In the last LNG export application it approved, the NEB states:

> *Our role, under s. 118 of the NEB Act, is to assess whether the natural gas proposed to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to trends in the discovery of gas in Canada (Surplus Criterion).*

And:

> *We have determined that the quantity of gas proposed to be exported by Prince Rupert LNG is surplus to Canadian need. The Board is satisfied that the gas resource base in Canada, as well as North America, is large and can accommodate reasonably foreseeable Canadian demand, the LNG exports proposed in this Application, and a plausible potential increase in demand.*

Is this true? Let's have a look at Canadian gas production in the light of the export applications NEB has approved.

Figure 1 illustrates Canadian gas production by province from 2000 through 2013. Canadian production peaked in 2002 and is now down 30 per cent from its peak. The only province with substantial growth is BC, which constitutes 28 per cent of Canadian production (although it is now on a plateau). Coupled with current BC production, which is mostly committed to existing customers, meeting the NEB export approvals to date would require increasing BC's gas production to nearly 50 per cent more than all of Canada currently produces - within less than a decade.

Let's look at where this gas is proposed to come from and what these approvals would mean.

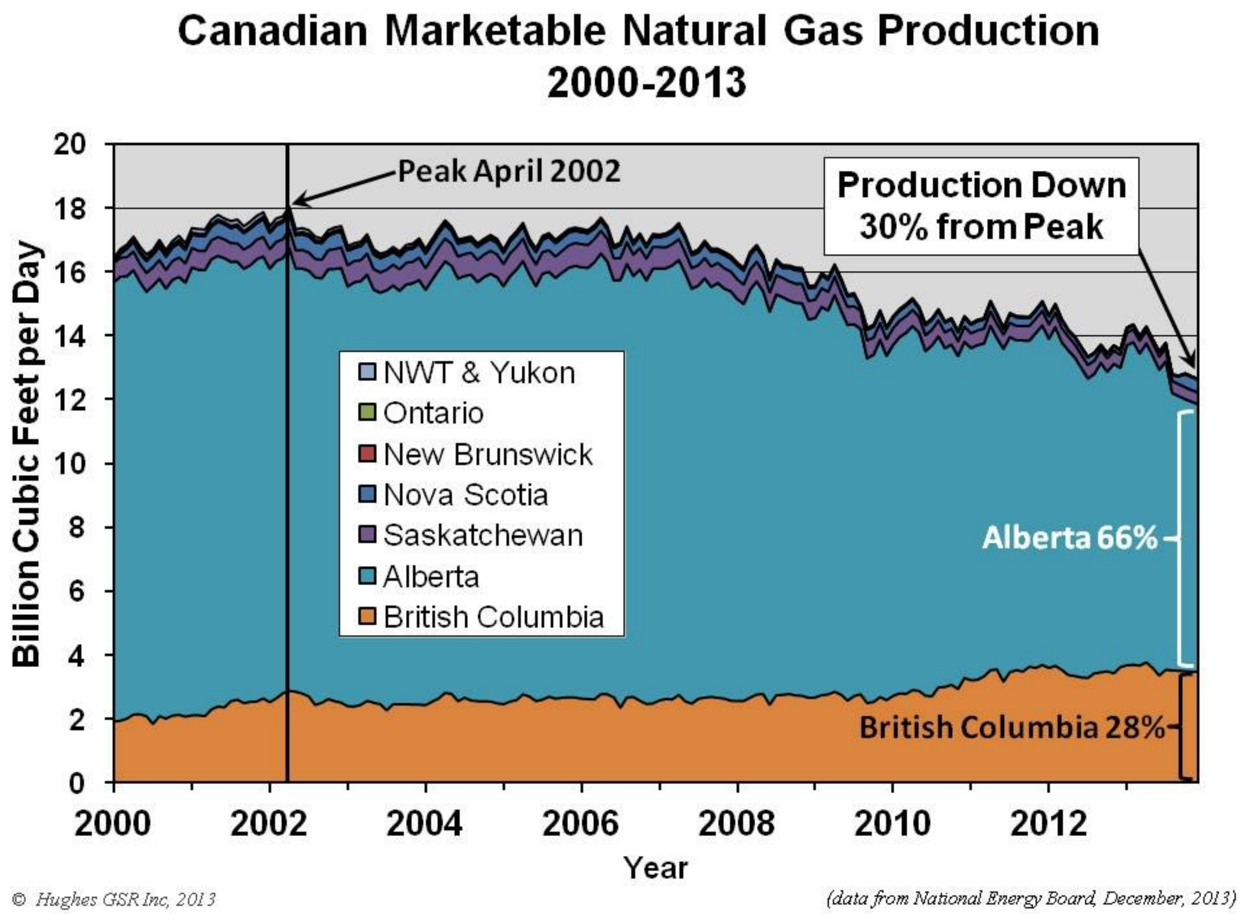

Figure 1 – Canadian gas production by province from 2000 through October 2013, based on NEB data.

BC Gas Production and Shale Realities

BC gas production has been underway since the 1940s. As of September, more than 25,000 wells had been drilled, of which 9,080 are currently producing. Although production has tripled from 1990 to the present, the number of wells required has increased six-fold (Figure 2).

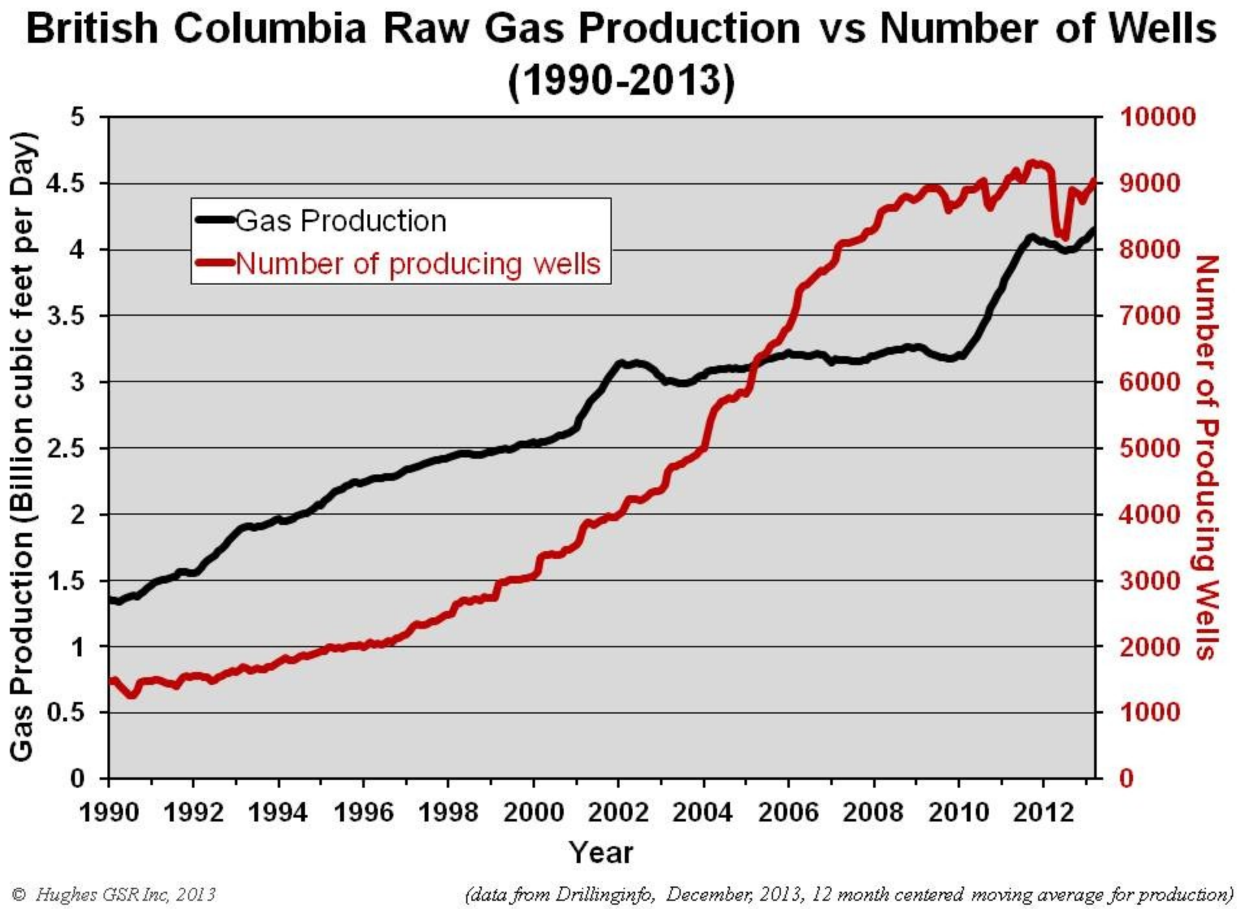

Figure 2 – British Columbia raw gas production versus the number of producing wells from 1990 through 2013.

The much trumpeted shale "revolution" in the U.S. has extended to Canada and much of the hope of greatly expanding BC gas production for export is based on the application of large scale horizontal drilling and multi-stage high volume hydraulic fracturing (fracking) of shale- and tight-gas reservoirs. Two such plays have come into prominence in BC in the past few years – the Montney and Horn River. Other evolving plays include the Cordova Embayment and Liard, although exploration there has been much more limited. Without the Montney and Horn River, BC gas production would be in steep decline (Figure 3).

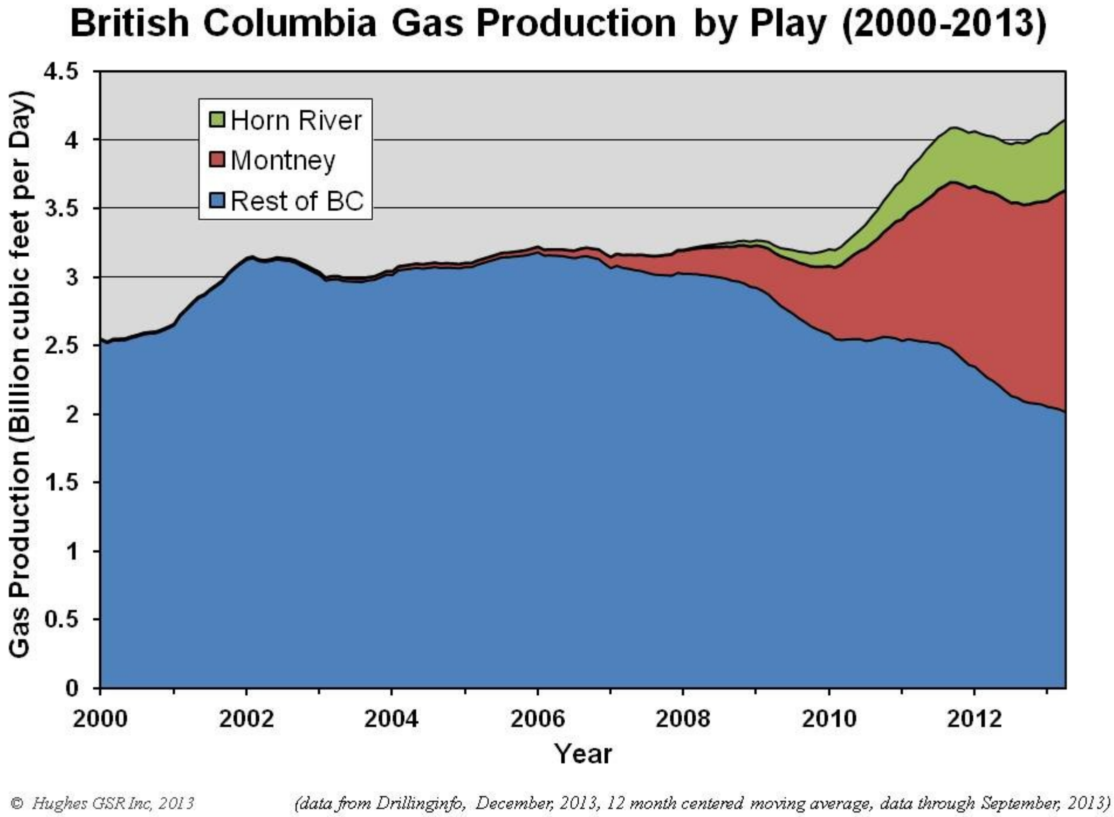

Figure 3 – BC gas production by play illustrating the importance of the Montney (tight gas) and Horn River (shale).

An analysis of shale gas in the U.S. reveals high well- and field-decline rates, which require an escalating drilling treadmill to maintain production.[5,6] The shale- and tight-gas plays of BC are similar. Figure 4 illustrates the average well production decline profiles for the Horn River, Montney and the rest of BC using data from Drillinginfo[7], a database of production data from all BC wells.

Horn River wells are on average more productive than the Montney and the BC average, but have well production declines averaging 80 per cent in the first three years, compared to 61 per cent for the Montney and 69 per cent for the BC average. Field decline in the Horn River, based on production from all wells drilled prior to 2012, averages 37 per cent, meaning that without new drilling production would decline by

37 per cent in one year. This compares to an average overall decline of about 26 per cent for all BC gas fields. Field declines of 26-37 per cent per year require considerable numbers of new wells to offset – the number of which can be readily calculated given the average productivity of new wells and the magnitude of the supply gap that must be filled.

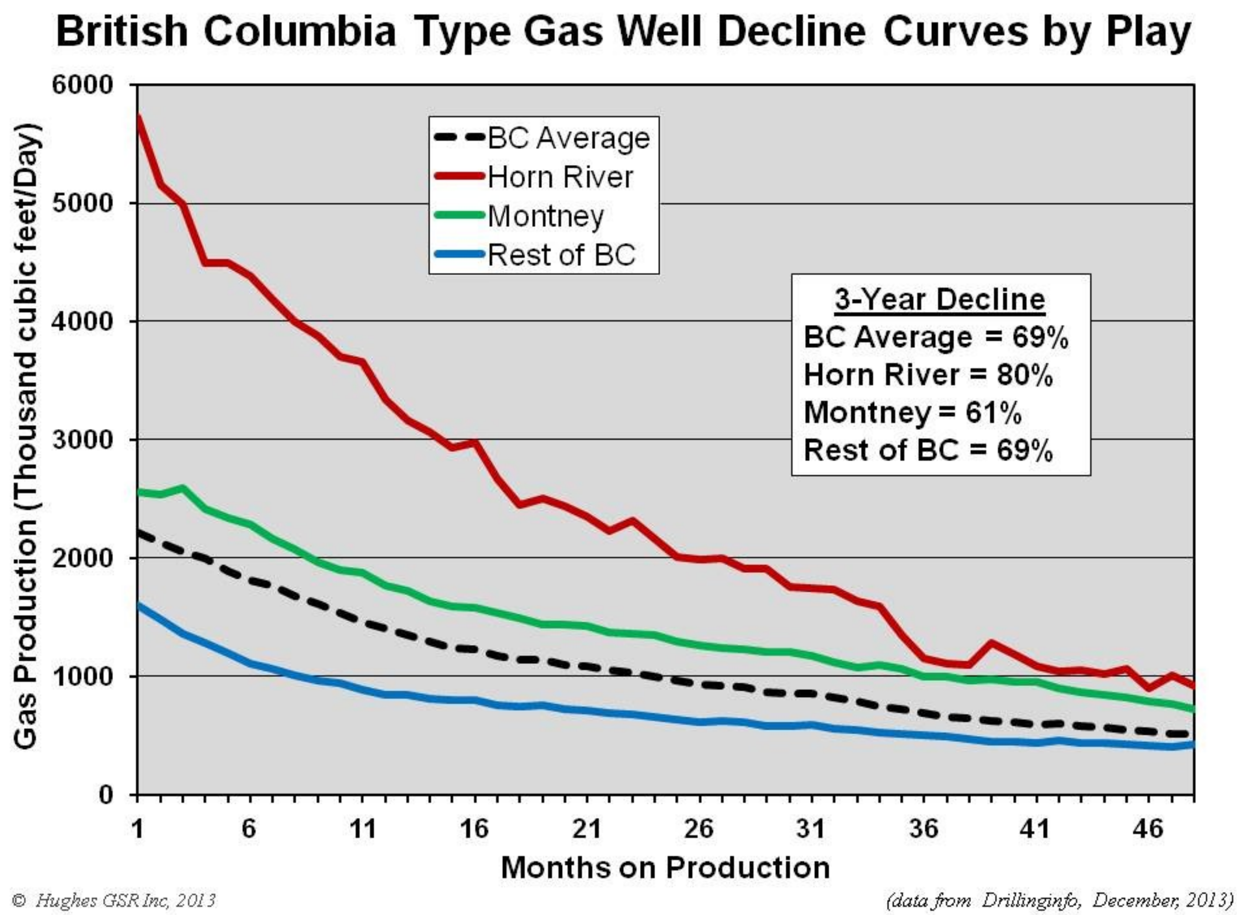

Figure 4 – Average well production decline curves for the Horn River, Montney and remainder of BC.

Production and Wells Required

The gas production required to meet various export levels is illustrated in Figure 5. The assumption in Figure 5 is that no company is going to spend several million dollars per well to drill a lot of surplus capacity until close to the time that the LNG export facilities would be in service. Hence drilling and production is assumed to ramp up in 2017 ahead of the LNG terminals projected start up in 2020.

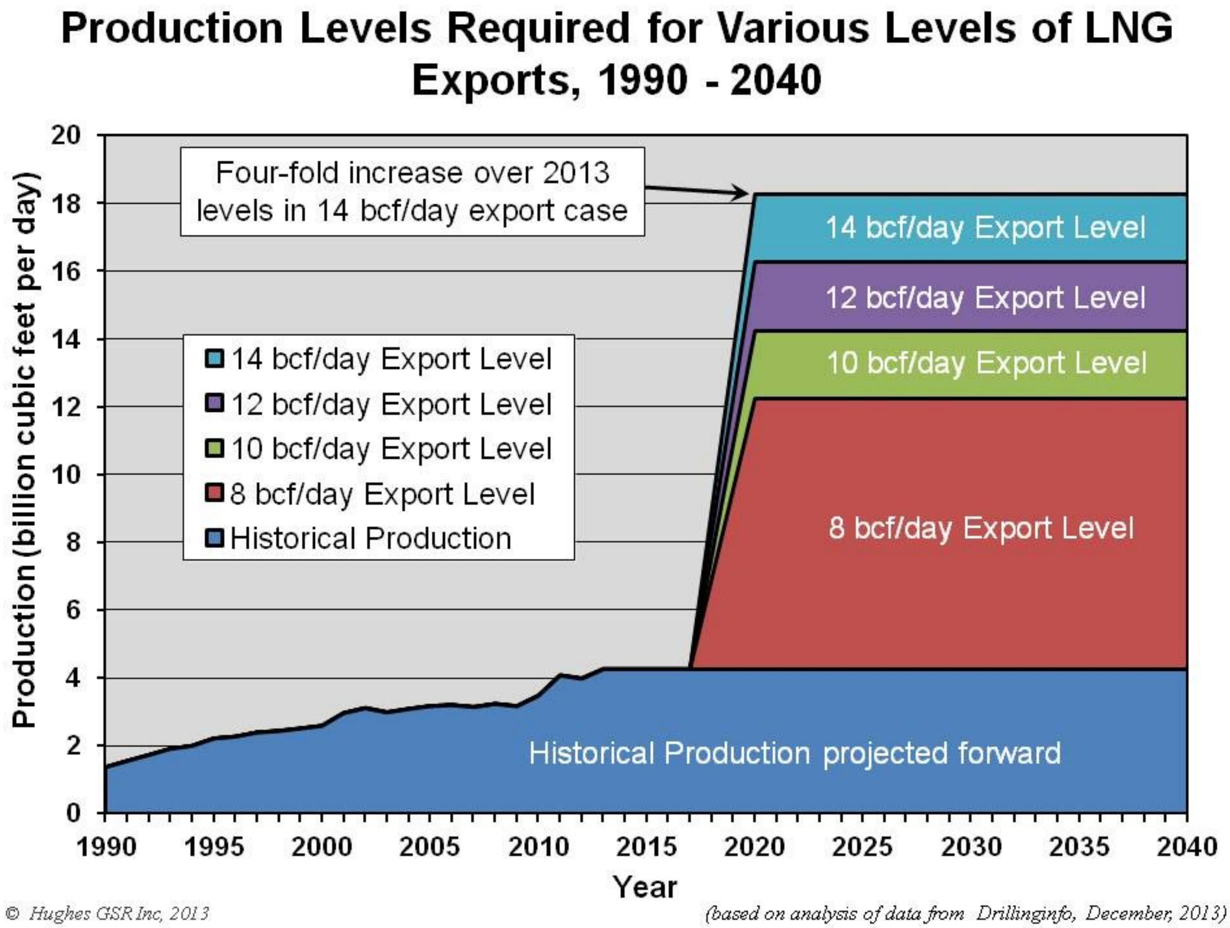

Figure 5 – Gas production required for various levels of LNG exports compared to existing raw gas production. The NEB has approved 14.6 bcf/d of exports with another 3.4 bcf/d under review.

So how many wells would this take? Assuming the existing productivity of new wells and field decline rates are maintained[8], Figure 6 illustrates the cumulative number of new wells that would be required to meet various export levels through 2040. Achieving the 14 bcf/d production level of gas for export would require drilling nearly 50,000 mostly fracked wells over the next 27 years, which is nearly double the more than 25,000 oil and gas wells drilled since the 1950s in BC. The 8 bcf/d export case would require 34,000 new wells by 2040. Production levels and the number of wells would in actuality have to be even higher as the gas typically has 10 per cent or more CO_2 and other impurities that must be removed to make "marketable" gas (typical shrinkage is 12-15 per cent). Furthermore this does not include the likely use of gas for power to liquefy the LNG, which would require the production of up to an additional 15 per cent. Hence this projection of the number of wells required is very conservative and likely underestimated by 15-30 per cent.

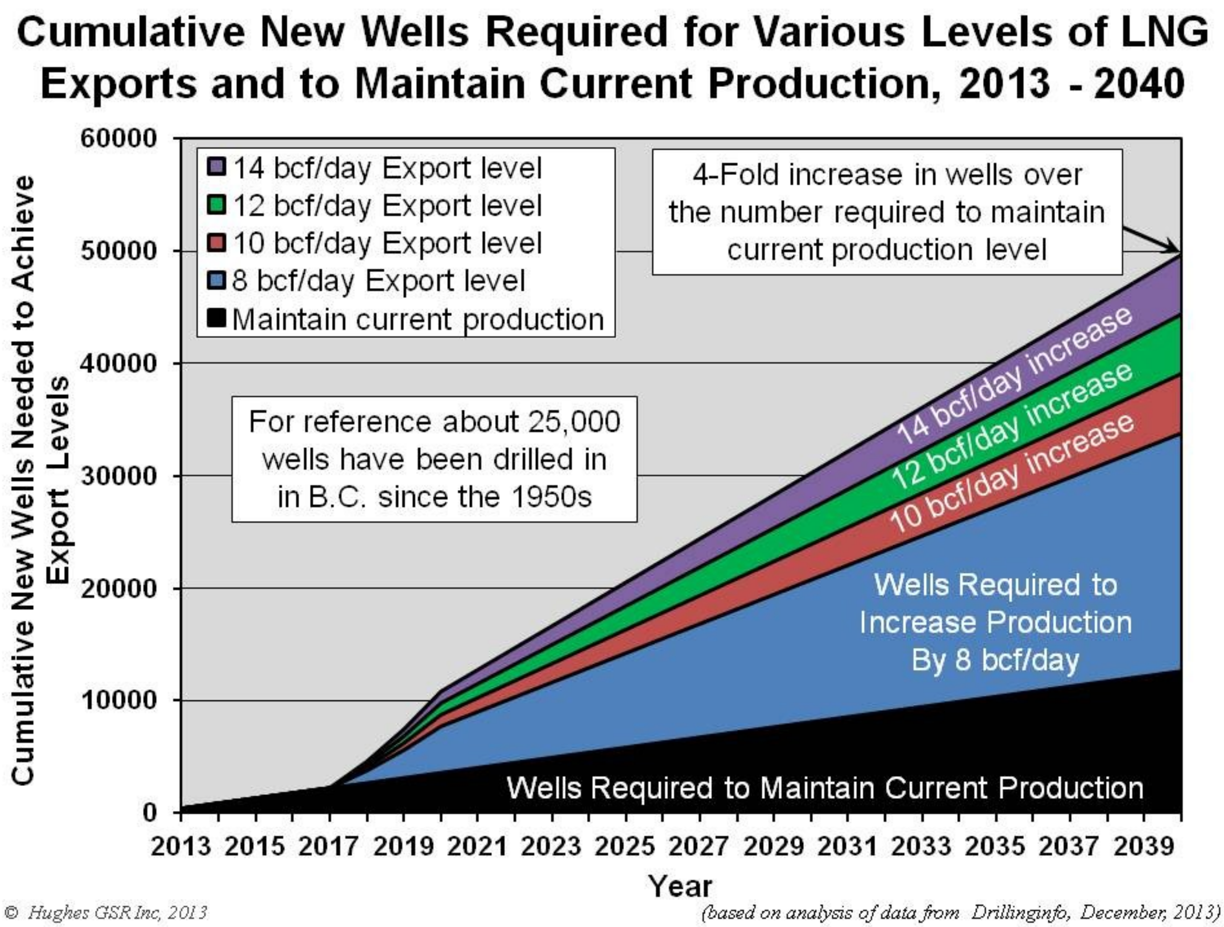

Figure 6 – Cumulative number of new wells required to meet various levels of export as well as maintain current production.

Is the NEB Looking After Our Interests?

The NEB published a "Canada's Energy Future" report in November 2013, which provided low, high, and reference cases for energy production and demand in BC and Canada through 2035.[9] Gas production is forecast to decline radically in every province but BC in its reference case (Figure 7).

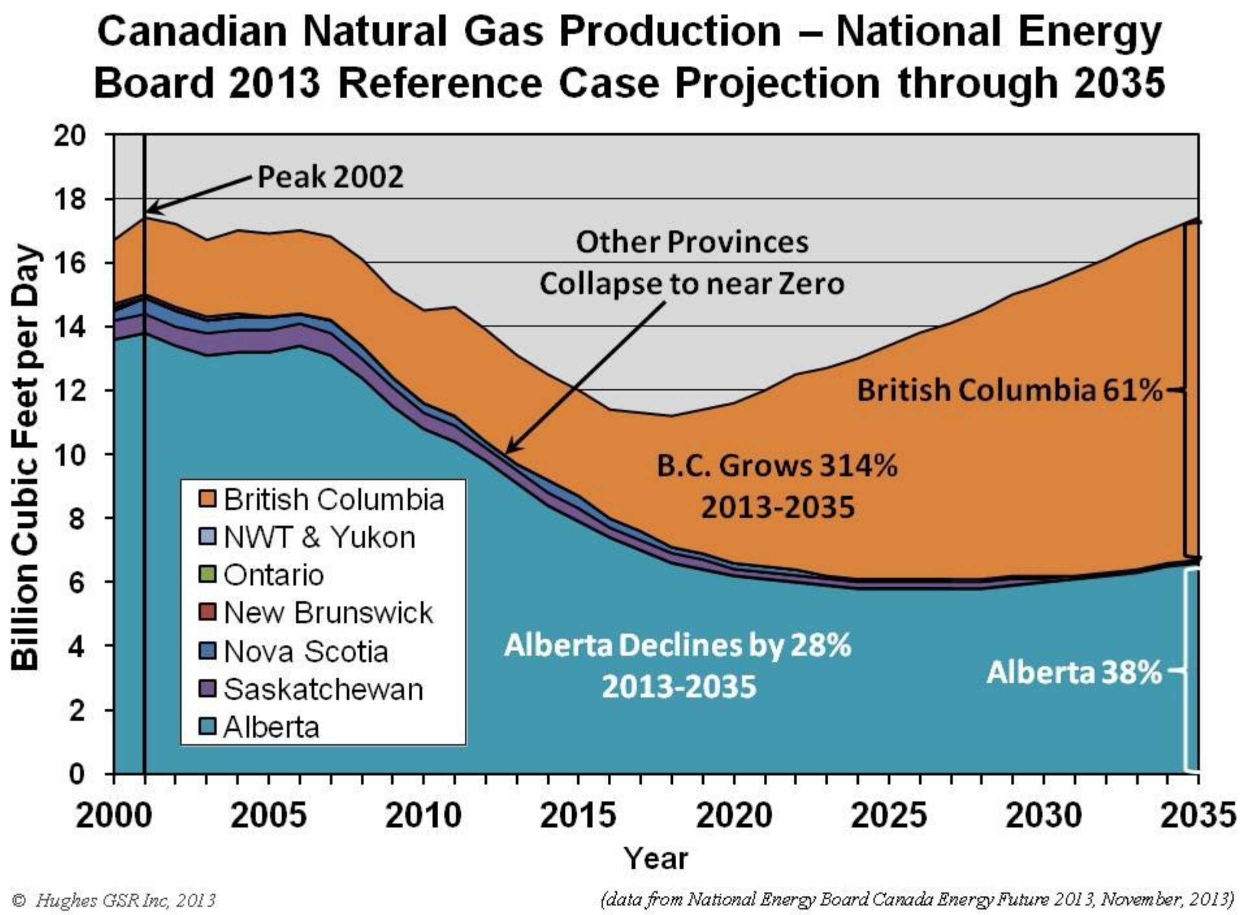

Figure 7 – NEB's reference case projection of gas production by province in Canada.

In its low production scenario, the NEB admits that Canada will become a net gas importer by 2017 and remain so thereafter. In its reference case, the NEB suggests Canada will have no more than 4.5 bcf/d of export capacity by 2035 – YET IT HAS APPROVED LNG EXPORTS OF 14.6 BCF/D STARTING IN 2020. On the face of it, approving all of these export applications would appear to be a serious dereliction of the NEB's mandate, which, as noted earlier, is to ensure that the long term energy security interests of Canadians are looked after.

Figure 8 compares the NEB's projections for BC gas production to the requirements of the approved permits. In no case are the NEB's forecasts even close to meeting these requirements. The NEB's reference case forecast would see 57 trillion cubic feet (tcf) of gas recovered by 2035, whereas the 14 bcf/d export case would require 120 tcf – more than twice as much (to put this in perspective only 25 tcf of marketable gas has been recovered in BC since the 1950s, and B.C's remaining recoverable marketable gas reserves were just 33.5 tcf at yearend 2012)[10,11].

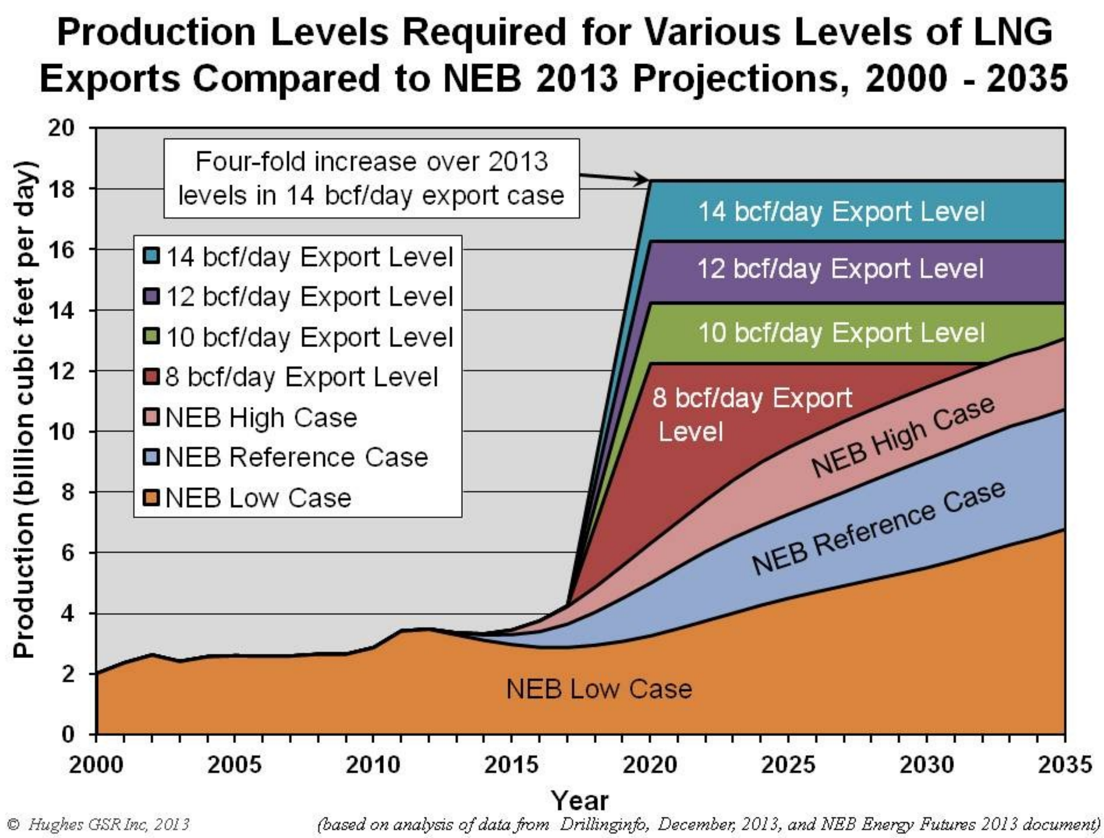

Figure 8 – NEB's projection of BC gas production compared to various LNG export level requirements.

The NEB forecasts falling production everywhere else in Canada, and current BC production is largely committed to existing uses, so one must ask where all the gas will come from for these LNG dreams – and at what cost to the long term energy security of Canadians?

Environmental Considerations

In 2012 the BC Oil and Gas Commission published a report that detailed water consumption and induced seismic activity associated with fracking in northeast BC.[12] Fracking would be the principal technology used to ramp up gas production for LNG exports. In addition to the earth tremors induced by fracking, the report documented water consumption in wells in the Horn River Basin that averaged over 16 million US gallons per well. This is much higher than the typical fracked well in the US at about 5 million gallons. Water consumption is correlated with the number of frack stages which is increasing as operators strive for higher production. The well with the largest number of frack stages cited in the report (27 stages) consumed 36 million gallons along with 5,484 tonnes of sand and other chemicals (Montney wells are reported to average considerably less at 3 million gallons each[13]).

If the BC government's LNG dreams become a reality and 50,000 new wells are drilled by 2040, what would the water consumption look like? Figure 9 illustrates the rate of drilling that would be required to achieve various export levels. In the 14 bcf/d export case drilling would have to grow to more than 3000 wells/year and then decline to nearly 2000 wells/year to maintain production. To put this in perspective, 3000 wells/year, each consuming 10 million gallons of water, is more than the total water consumption of Calgary, a city of over a million people. The difference between Calgary and fracking is that in Calgary the water is treated and returned to the environment, whereas with fracking much of the water injected remains permanently in the reservoir, and of what returns to the surface little is recycled – most is injected into disposal wells permanently removing it from the hydrological cycle.

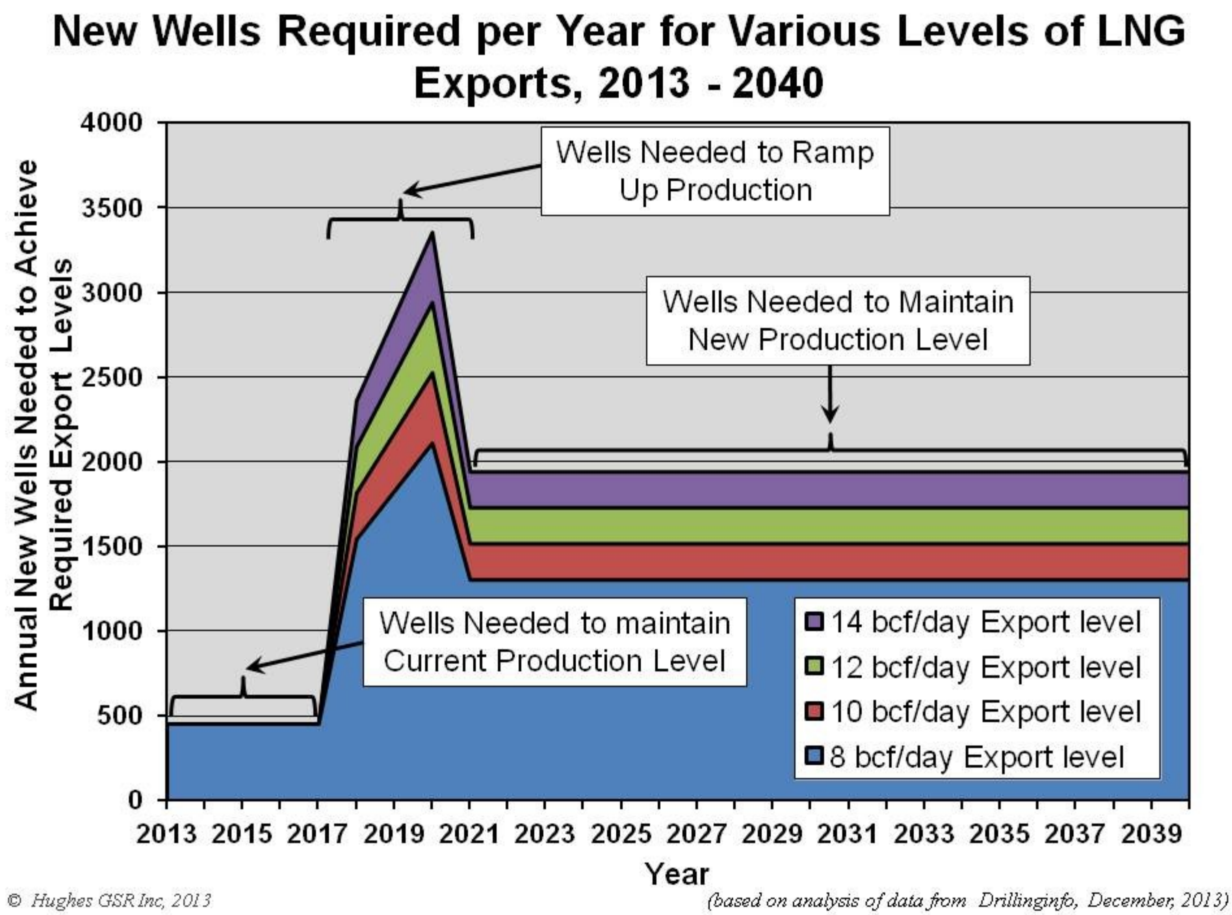

Figure 9 – The rate of annual drilling required to meet various LNG production targets illustrated in Figure 5.

Where would this water come from and what are the implications? Other documented concerns with fracking are potential groundwater contamination through casing failures, improper frack water disposal, industrial footprint, and greenhouse gas emissions from vented methane and carbon dioxide.

Environmental organizations in many parts of the world oppose fracking and moratoriums are in place in Quebec, New York State, Maryland and France.

Implications

The LNG export plans of the BC government are unlikely to be realized at the scale envisioned and must be seriously questioned.

Given the gas production forecasts of the NEB, which show production falling in every province but BC, the large scale export of gas will compromise Canada's long term energy security. The NEB assures us that even if Canada becomes a net gas importer by 2017 (as in its "low case" forecast), shale gas in the U.S. will be available at low prices. This is by no means a certainty given the fundamentals of U.S. shale gas production and cost, as well as its own LNG export plans.

The NEB appears to have violated its mandate to ensure Canadian energy security by approving seven LNG export applications, which add up to more than the current gas production of all of Canada, and far exceed even its most optimistic projections of BC gas production. To put this in perspective, the US, which produces five times as much gas as Canada, has approved only four export projects with a total capacity of less than half that of the NEB approvals.

The public would be well advised to demand more from their government than an improbable LNG fix to address crucial long term energy security, environmental, and fiscal problems.

Arm-waving assertions by BC politicians of more than 950 tcf[14] of recoverable resources are misleading, as they convey none of the geological and economic uncertainties in these estimates, nor the scale of the environmental and technical challenges in attempting to recover them. Natural gas is a finite, non-renewable resource; however it will continue to be an important energy input to BC and Canada for the foreseeable future. Liquidating BC's gas resources as quickly as possible is not a sustainable energy plan. Long term energy sustainability must of necessity involve a reduction in our reliance on non-renewable resources and a vision of how to get there.

David Hughes is a geologist and veteran of three decades with the Geological Survey of Canada. He is president of Global Sustainability Research and a Fellow of the Post Carbon Institute.

---

[1] First published at Watershed Sentinel, January 17,2014, http://watershedsentinel.ca/content/david-hughes-bc-lng-reality-check

[2] BC Government, accessed December, 2013, "LNG in BC: Projects and Communities", http://engage.gov.bc.ca/lnginbc/first-nations-and-communities/

[3] Fowlie, Jonathan, February 13, 2013, Vancouver Sun, "Christy Clark projects $100 billion LNG windfall for B.C. in throne speech", http://www.vancouversun.com/news/Christy+Clark+projects+billion+windfall+throne+speech/7953712/story.html#ixzz2qgq822Bihttp://www.vancouversun.com/news/Christy+Clark+projects+billion+windfall+throne+speech/7953712/story.html

[4] National Energy Board, Accessed December 2013, "LNG Export Application Schedule", http://www.neb-one.gc.ca/clf-nsi/rthnb/pplctnsbfrthnb/lngxprtlcncpplctns/lngxprtlcncpplctns-eng.html#s1

[5] Hughes, J.D., 2013, "Drill, Baby, Drill: Can Unconventional Fuels Usher in a New Era of Energy Abundance?", Post Carbon Institute, http://www.postcarbon.org/reports/DBD-report-FINAL.pdf

[6] Hughes, J.D., 2013, "Tight Oil: A Solution for U.S. Oil Imports?", Geological Society of America Conference, Denver, USA, October 28, 2013, https://gsa.confex.com/gsa/2013AM/webprogram/Handout/Paper226205/HUGHES%20GSA%20Oct%2028%202013%20-%20Short.pdf

[7] Drillinginfo, accessed December, 2013, "Western Hemisphere Coverage", http://info.drillinginfo.com/coverage/western-hemisphere/

[8] Field decline rates of 26% per year are assumed (the current BC average), which is conservative considering that the Montney and Horn River plays, which would make up a lot of the new production, are higher. Average first year production rates of 2444 mcf/d of raw gas are assumed, which is the current BC average.

[9] National Energy Board, 2013, "Canada's Energy Future 2013: Supply and Demand Projections to 2035", http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2013/nrgftr2013-eng.pdf

[10] BC Oil and Gas Commission, 2013, "2012 detailed Gas Reserves by Field and Pool (Excel)", http://www.bcogc.ca/2012-detailed-gas-reserves-field-and-pool-excel ; Reserves are estimated to be economically recoverable with existing technology. In place resources are far higher but are not constrained by economics, recovery factors, shrinkage factors etc.

[11] BC Oil and Gas Commission, 2013, "Hydrocarbon and By-Product Reserves in British Columbia", http://www.bcogc.ca/node/11111/download . This reference only lists raw gas reserves which are 40.2 tcf as of yearend 2012. As raw gas contains CO_2 and other impurities that must be removed before sale, the actual marketable reserves were 33.5 tcf per footnote 9. Some of these in place resources will be converted to recoverable reserves over time with more exploration and development.

[12] http://www.bcogc.ca/node/8046/download?documentID=1270

[13] BC Oil and Gas Commission, 2013, "Hydrocarbon and By-Product Reserves in British Columbia", http://www.bcogc.ca/node/11111/download .

[14] BC LNG Quiz, 2013, http://engage.gov.bc.ca/lnginbc/quiz/#/start/