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June 22, 2018

B.C. Sustainable Energy Association
c/o William J. Andrews, Barrister & Solicitor
1958 Parkside Lane
North Vancouver, B.C.
V7G 1X5

Attention: Mr. William J. Andrews

Dear Mr. Andrews:

Re: FortisBC Energy Inc. (FEI)

Project No. 1598946

2017 Long Term Gas Resource Plan (LTGRP) (the Application)

Response to the B.C. Sustainable Energy Association and Sierra Club of British Columbia (BCSEA) Information Request (IR) No. 2

On December 14, 2017, FEI filed the Application referenced above. In accordance with British Columbia Utilities Commission Order G-33-18 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCSEA IR No. 2.

If further information is required, please contact Ken Ross at (604) 576-7343.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

46.0 Topic: FEI efforts to reduce carbon emissions from the natural gas stream

Reference: Exhibit B-3, FEI Response to BCSEA 1.1; Exhibit B-1, Action Plan, Activity 8, pdf p.244

In response to BCSEA IR 1.1, FEI lists seven projects it is "exploring" that support innovative gas technologies that will help FEI meet its customers' preferences for gas while also addressing provincial plans for reducing GHG emissions. FEI refers to Action Plan Activity 8 and says it may seek approvals to increase its ability to financially support investigations of innovations that will help its customers reduce emissions and keep energy costs low.

The 2017 LTGRP Action Plan "describes the activities that FEI intends to pursue over the next four years based on the information and recommendations provided in this 2017 LTGRP." Activity 8 is:

> "8. Pursue approvals as necessary of a funding envelope dedicated to enabling FEI to further monitor and, where applicable, support innovative natural gas technologies which may help FEI meet market preferences while also supporting solutions for BC's emissions policy objectives."

In its response to BCSEA-SCBC IR 1.42.2, FEI says that Activity 8 includes activities to support the development of cellulosic biogas technologies.

46.1 Please explain why FEI is merely "exploring" the seven listed projects regarding innovative gas technologies rather than vigorously participating in them. Is there a shortage of funding, or uncertainty about the benefit/cost?

Response:

This response also addresses BCSEA IR 2.46.2.

FEI is at present actively pursuing all projects listed in the response to BCSEA IR 1.1.1 and some of the projects are in the early stages of development, and therefore subject to various uncertainties. FEI may pursue approval for funding to further advance these projects, either individually or as part of a larger initiative, when the requirements of these projects exceed the Company's ability to provide sufficient funding from the existing funding envelope.

46.2 To what degree is FEI committed to carrying out Action Plan Activity 8? Where the response to BCSEA-SCBC IR 1.1 says FEI "may" seek approvals for funding, does that indicate less than full commitment?

Response:

As with FEI's other innovative service initiatives (e.g., DSM, RNG and TES), FEI is fully committed to pursuing the innovative natural gas technology projects described in the response to BCSEA IR 1.1.1 through to their conclusion in the hope and expectation that some or all of the projects will prove to be viable. FEI maintains that innovation in this regard is vital to the interests of its customers and the long-term future of the gas utility. FEI is therefore also committed to pursuing approval of a funding envelope, as needed, to enable these projects to proceed. FEI will seek approval(s) of a funding envelope when the requirements of these projects necessitate additional funding sources.

46.3 Please describe the topics that will be included in the Activity 8 envelope.

Response:

FEI cannot describe the topics with certainty at this time as the innovative natural gas technologies to be included in the Activity 8 envelope will be determined as they become available and pursued once they appear viable. The projects identified in the response to BCSEA IR 1.1.1 provide a good representation of both the type and perhaps the specific projects that may be included in a funding envelope request.

46.4 Please describe the regulatory framework under which Activity 8 would be carried out.

Response:

FEI cannot comment at this time on the regulatory framework as the particulars of the activities that will support innovative natural gas technologies will be determined as potential and viable projects become available. FEI currently has regulatory frameworks for its Conservation and

Energy Management (i.e., DSM) programs, Renewable Natural Gas and Natural Gas for Transportation initiatives supported by the Demand-Side Measures Regulation under the UCA, or the Greenhouse Gas Reduction (Clean Energy) Regulation under the CEA, as well as past Commission decisions respecting these initiatives. Some pursuits under Activity 8 may fit within these existing regulatory frameworks or, at a minimum, the existing regulatory frameworks would provide models to guide the development of another regulatory framework, if necessary.

46.4.1 Under what section of the UCA would the approvals be sought?

Response:

FEI sees two main patterns for UCA approvals that might be required in relation to Activity 8 projects or expenditures. The first approach would be to seek approval of an expenditure schedule under section 44.2 of the UCA for the Activity 8 spending envelope, accompanied by an application for recovery of the expenditures in rates under sections 59 to 61 of the UCA. The second approach would apply to a situation where the Activity 8 expenditures qualify as prescribed undertakings under section 18 of the *Clean Energy Act*. In that case, the Commission has previously accepted prescribed undertaking status as confirming the need for the expenditures, so no CPCN or expenditure schedule approval would be needed. UCA approval under sections 59 to 61 of the UCA for recovery of the expenditures in rates would be the extent of the approvals sought in the second case.

46.4.2 Please discuss how these approval applications would relate to FEI's Performance Based Ratemaking framework.

Response:

Given the nature of the proposed types of projects and initiatives that may be covered by an Activity 8 funding application, FEI does not believe it would be appropriate to include the associated expenditures in any formula-based element of the current or future PBR plan. Similar to DSM spending and spending under the GGRR, any approved spending for Activity 8 initiatives should, in FEI's view, be outside the PBR formulas. Including Activity 8 expenditures within a broader incentive framework such as the current O&M and capital formulas would be likely to have the perverse result of encouraging the utility not to pursue the initiatives.

46.4.3 Would the spending under the Activity 8 envelope be capital spending?

Response:

Spending under an Activity 8 envelope may include capital expenditures and other spending that is not capital. For non-capital expenditures, FEI expects to pursue similar rate treatment as that afforded to DSM expenditures and NGT incentives under the GGRR (e.g., deferral and amortization in rates over a number of years).

46.4.4 Does FEI intend to rely on the GGR(CE) Regulation in support of Activity 8?

Response:

To the extent that Activity 8 initiatives qualify as prescribed undertakings, either those currently in place or those that may be established in the future, FEI would anticipate relying on the GGRR to advance the initiatives.

46.5 Please confirm, or otherwise explain, that activities to be carried out with the funding for which approvals will be pursued are different that the activities within the C&EM Innovative Technologies program area.

Response:

Confirmed. FEI generally sees the initiatives to be pursued under an Activity 8 spending envelope as different than the activities within the C&EM Innovative Technologies program area. However, there is overlap in some cases, meaning it is possible that certain future initiatives could be characterized as either.

47.0 Topic: Annual Energy Demand Forecasting

Reference: Exhibit B-1, Appendix B-5, Appendix B-5_Annual Demand Forecast Data_LS.xlsx

The live spreadsheet shows results only for Natural Gas, CNG, LNG and RNG. After FEI made the spreadsheet and the LTGRP Application publicly available in December 2017, a member of FEI's Resource Planning Advisory Group asked FEI by email of December 17, 2018 for a version of the spreadsheet that also shows the results for <u>electricity</u> consumption. He said:

> "Am I correct in assuming that the end-use model also tracked electricity consumption? Would it be possible to get that data as well, so we can understand better the impact on electricity demand of the diverse scenarios?"

FEI's Integrated Resource Planning Manager responded by email of December 20, 2017 that:

> "We did not include this information in our submission to the BCUC. We would prefer to answer your question in the public hearing process to ensure that our response is included in the public record so that all stakeholders get equal access to both the question and the response."

47.1 Please provide a live spreadsheet version of Appendix B-5 (Annual Demand Forecast Data_LS) that includes all fuel types, including end-use electricity demand, for each of the six demand scenarios.

<u>Response:</u>

FEI consulted with Posterity Group Consulting Inc. (Posterity) to provide the following response.

FEI interprets this request to ask for electricity and low carbon thermal annual demand as Appendix B-5 of the Application contains annual demand for natural gas, CNG, LNG, and RNG already. Refer to Attachment 47.1 for a live spreadsheet version of data similar to that in Appendix B-5 which contains annual demand results for "Electricity" and low carbon thermal (represented by the "District Energy" and "Renewable energy" fuel codes in the appendix).

As noted in Section 8.2.3 of the Application, both low carbon thermal and electricity annual demand simply represent outcomes of how the 2017 LTGRP scenario analysis method accounts for potential fuel switching across the alternate future scenarios. Unlike the natural gas demand forecast, results for these two fuel types are not calibrated to any base year actuals or base year end-use breakdowns. As noted in Section 8.2.3 of the Application, a complete analysis of electricity demand is outside of the scope of the LTGRP. FEI has thus not performed the quality control steps on electricity demand that FEI performed for the fuel types that it did publish in the Application. For these reasons, the results added to the live spreadsheet in Attachment 47.1 are not comprehensive forecasts and do not represent FEI's opinion of future low carbon thermal and electricity annual demand.

In summary, the natural gas demand forecasting completed by FEI for the LTGRP should not be considered an all-fuels forecast. Rather, the outcome of using these fuels in the modelling shows FEI's forecast of natural gas demand after the impact of representative alternative fuels.

48.0 Topic: Annual Energy Demand Forecasting

Reference: Exhibit B-1, Chapter 3, Annual Energy Demand Forecasting

"The Reference Case, which is based on known, legally enshrined and mandatory requirements, assumes that the 2014 iteration of the BC Building Code (BCBC) will remain unchanged across the planning period. This is an important starting point against which to compare other outcomes on this critical uncertainty.

Nevertheless, BC has enacted the BC Energy Step Code and the provincial CLP [Climate Leadership Plan] declares a goal of net zero ready new construction for 2032. To account for the plausibility of future changes in the BCBC, the 2017 LTGRP progressively applies the voluntary and non-time bound steps from the BC Energy Step Code across relatively even time periods throughout the planning horizon in order to achieve the CLP's 2032 target. As such, 2017 LTGRP scenarios that are subject to the Accelerated outcome on the Non-Price Carbon Policy critical uncertainty, assume that the entire province moves along this step code ladder over time as the BCBC is updated. Figure B1-10 below illustrates this dynamic for a subset of dwellings: ..." [pdf p.274]

The Action Plan is based on the Reference Case. FEI states: "Pursuant to Order G-189-14, dated December 3, 2014, FEI confirms that it has built this Action Plan based on its Reference Case end-use annual demand forecast and its Traditional Peak Method forecast." [Exhibit B-1, pdf p.242]

48.1 Please confirm that the Reference Case annual energy demand forecast uses the 2014 BC Building Code throughout the planning period.

Response:

Confirmed.

48.2 Please confirm that the BC Building Code is regularly updated, and over the last several code revisions it has incorporated more-stringent energy efficiency requirements.

Response:

FEI can confirm that the BC Building Code (BCBC) is updated over time though these updates happen at varying regularity. Energy efficiency requirements often do increase with new code cycles but this is not always the case; some code cycles have not resulted in increased efficiency requirements. For example, in the initial release of the 2012 version of the BCBC, energy efficiency requirements remained unchanged from revision 2 of the 2006 BCBC made in 2008.

48.3 Does FEI agree that it is reasonable to expect that the 2014 BC Building Code will be amended to incorporate more-stringent energy efficiency requirements during the planning period, although the extent and timing of such changes may be uncertain?

Response:

For greater certainty, when stating "2014 BC Building Code" FEI means the 2012 British Columbia Building Code containing revisions and amendments up to December 19, 2014. FEI agrees that it is reasonable to expect the BC Building Code will be amended in the future based on the expectation that the building code follows a five year code cycle update. It is likely that future revisions to the current building code or a future update of the BC building code itself will incorporate changes on using updated standards to promote improvement of energy efficiency requirements. This may or may not occur throughout the planning horizon. FEI agrees that the extent and timing of such changes are uncertain.

48.4 Would FEI agree that the most reasonable assumption for the Reference Case would be to assume that the province adopts successive levels of the Step Code with each revision, reaching Step 5 or "net-zero energy ready" by 2032 (three code revisions, more or less)? If not, why not?

Response:

FEI disagrees with the assertion that the most reasonable assumption for the Reference Case would be to assume that the province adopts successive levels of the BC Energy Step Code with each revision.

The asserted trajectory is one of multiple plausible trajectories. Revision 11 to the 2012 BC building code only specifies voluntary energy targets for each respective step, with no direction on adopting specific step code levels. As noted on page 11 of Appendix E of the Application, the BC Energy Step code is a voluntary standard whose steps are not tied to specific implementation dates.

Historically, the BC Building Code releases occur with varying regularity, adding uncertainty to reaching Step 5 under any reasonably defined time scale.

Implementation of code changes is dependent in part on the market (builders, HVAC contractors, manufactures, architects etc.) ability to implement a code change. Generally, changes to code are implemented such that the market can seamlessly make the adaptation. As the Step Code is not a prescriptive code it is not known at this time if the market is able to implement the code effectively and efficiently. This may therefore affect further implementation of higher levels of the code.

Further, the implementation and timing for meeting such step code targets is also driven by BC municipalities, which all have disparate proposed timelines to adopting Step Code targets. With BC municipalities just beginning to consider how they will make use of the BC Energy Step Code, it is unclear at this stage how successful such voluntary implementation efforts will be.

48.5 FEI says the Reference Case "is based on known, legally enshrined and mandatory requirements." Does this mean that the Reference Case is based on existing legal requirements even where FEI expects existing legal requirements to change in a known direction during the planning period?

<u>Response:</u>

This response also addresses BCSEA IRs 2.48.5.1, 2.48.6, and 2.48.7.

The Reference Case provides a baseline against which forecast demand under five alternate future scenarios is examined. The 2017 LTGRP end-use annual demand forecast method generates these scenarios by relying on a set of critical uncertainties. As such, the Reference Case is based on known, legally enshrined and mandatory requirements as it seeks to minimize uncertainty about the magnitude, direction, and timing of changes in forecast inputs. This means that the Reference Case holds constant certain inputs even if FEI expects that these inputs may change in the future because FEI views the timing, magnitude or direction of this change to be uncertain. Likewise, the Reference Case cannot simply be defined as the status quo. A hypothetical example illustrates this: if the current legally effective minimum performance requirement for an energy appliance is 85 percent but currently implemented legislation mandates this to increase to 95 percent in ten years, the Reference Case will account for this known increase even though the status quo is 85 percent. As noted in FEI's response to BCSEA IR 2.48.3, FEI views as uncertain the timing and extent of potential future stringency increases in BC Building Code energy performance requirements.

As noted in Section 9 of the Application, the Action Plan describes those activities that FEI intends to pursue over the next four years. Pursuant to Order G-189-14, dated December 3, 2014, FEI confirms that the Action Plan is built on the basis of the Reference Case end-use annual demand forecast and FEI's Traditional Peak Method Forecast. This means that the Action Plan may exclude multiple plausible alternate future scenarios. To cater for such uncertainty, the 2017 LTGRP includes directional discussions about how its resources (DSM, System Infrastructure, and Gas Supply) may be impacted under the Upper and Lower Bound scenarios.

48.5.1 Should the Reference Case be understood to represent the *status quo* extended over the planning period?

Response:

Please refer to the response to BCSEA IR 2.48.5.

48.6 With reference to Figure B1-1: Classification of 1 Planning Environment Variables [Exhibit B-1, pdf p.265], is the Reference Case based on categorizing as "Uncertain" any and all future additions of more-stringent energy efficiency requirements to the BC Building Code?

Response:

Please refer to the response to BCSEA IR 2.48.5.

48.7 If the four-year Action Plan is based solely on the Reference Case, and the Reference Case intentionally excludes reasonably foreseeable developments over the planning period, is the four-year Action Plan based on exclusion of reasonably foreseeable developments over the planning period?

Response:

Please refer to the response to BCSEA IR 2.48.5.

49.0 Topic: Annual Energy Demand Forecasting

Reference: Exhibit B-1, Appendix B-1

Under the heading 1.2.1.4.3 Other Policy Actions that May Result in Fuel Switching, FEI states:

> "In the 2017 LTGRP, fuel switching occurs as function of price response (to natural gas cost or carbon price) but not as function of efficiency increases in new construction. For example, a home that is built to the ENERGY STAR® standard rather than current BCBC levels in the model, does not automatically switch from one fuel to another. This treatment of efficiency increases is consistent with how the BC CPR treats such increases.
>
> To account for the impact of such effects and the effects of undetermined policy actions that may compel customers to switch from natural gas to another fuel type (e.g. Orders in Council 100 and 101, discussed in Section 2.3.3.5 of the 2017 LTGRP), the 2017 LTGRP scenario analysis includes a backstop mechanism that mandates minimum levels of fuel switching across the planning period for scenarios that are subject to the Accelerated outcome on the Non-Price Carbon Policy Action critical uncertainty. The backstop levels are based on updates of research conducted for the 2014 LTRP and, for the residential sector specifically, extrapolated fuel share change data from the BC CPR. The backstop levels break out as follows:
>
> - Across the planning period, 15 percent of commercial buildings connect to district energy systems and are thus removed from FEI's natural gas system;
> - If not motivated by price response already, at least the following amount of switching from natural gas to other fuels occurs for the following buildings across the planning period:
>   - Depending on their location and building type, 26 to 36 percent of residential dwellings and apartment buildings switch their space heating and 16 to 25 percent switch their domestic hot water away from natural gas;
>   - In addition to district energy connections, 2 percent of commercial buildings switch their hot water loads away from natural gas; and
>   - 1 percent of industrial facilities switch their hot water loads away from natural gas." [pdf pp.276-277]

49.1 What is the basis of the fuel switching assumptions [in the bulleted paragraphs quoted above] used in the Accelerated Non-Carbon Price scenarios?

Response:

This response also addresses BCSEA IRs 2.49.2 and 2.49.3.

The 2014 LTRP contains two assumptions that are similar to the 2017 LTGRP Non-Price Policy Action critical uncertainty: "Policy focused on carbon reduction" and "Renewable thermal & energy efficiency, including the use of 'Smart' technology". In the 2014 LTRP, "Policy focused on carbon reduction" impacts equipment efficiency and replacement rates but does not impact fuel shares. As such, the 2014 LTRP "Renewable thermal & energy efficiency, including the use of 'Smart' technology" is most comparable with the 2017 LTGRP Non-Price Carbon Policy Action critical uncertainty. Please see below for a table which compares the 2014 LTRP and the 2017 LTGRP on the bulleted paragraphs quoted in the question and outlines the basis of the quoted fuel switching assumptions in the 2017 LTGRP. FEI consulted with the Resource Planning Advisory Group on these assumptions for the 2017 LTGRP.

As explained in Table B1-2 of the Application, long-run fuel shares do respond to price changes due to the Natural Gas Price and the Carbon Price critical uncertainties but not the Non-Price Policy Action critical uncertainty. In FEI's view, significant uptake of electric heat pumps is a symptom but not a driver of fuel share changes. As explained in Section 1.2.1.4.3 of Appendix B-1 of the Application, the Non-Price Carbon Policy Action critical uncertainty helps account for the impact of undetermined policy actions that may compel customers to switch from natural gas to another fuel type. Regulations and incentives fall under this category of undetermined policy actions. Page 13 of Appendix B-1 of the Application also explains that, in the 2017 LTGRP scenario analysis, fuel switching does not occur "as function of efficiency increases in new construction. For example, a home that is built to the ENERGY STAR® standard rather than current BCBC levels in the model, does not automatically switch from one fuel to another. This treatment of efficiency increases is consistent with how the BC CPR treats such increases". In FEI's view, a switch back to electric resistance heating is not an automatic consequence of much lower heating demand in new buildings. As noted in Section 2.4.3 of the Application, innovative small-scale residential natural gas end-use appliances, are designed to meet the reduced heating requirements of more energy efficient newly constructed buildings.

The table below compares the 2017 LTGRP to the 2014 LTRP for the items identified in this question.

2017 LTGRP Bullet Items Quoted in Question	2014 LTRP Assumptions	Basis for use in the 2017 LTGRP
26 to 36 percent of residential dwellings switch their space heating and domestic hot water away from natural gas [by 2036].	1.5 percent of new and 0.75 percent of existing dwelling switch their space heating, domestic hot water and pools away from natural gas by 2021 and then stabilize.	Extrapolated from End Use Intensity changes considered by the BC CPR for construction of the BC CPR Reference Case.
2 percent of commercial buildings switch their hot water loads away from natural gas [by 2036].	1.5 percent of new and 0.75 percent of existing commercial buildings switch their hot water loads away from natural gas by 2021 and then stabilize.	FEI expert opinion to account for the 2017 LTGRP planning horizon in absence of conclusive updates to quantitative research.
1 percent of industrial facilities switch their hot water loads away from natural gas [by 2036].	0.75 percent of new and 0.5 percent of existing industrial facilities switch their hot water loads away from natural gas by 2021 and then stabilize.	FEI expert opinion to account for the 2017 LTGRP planning horizon in absence of conclusive updates to quantitative research.
Across the planning period, 15 percent of commercial buildings connect to district energy systems and are thus removed from FEI's natural gas system.	By 2030, 9 percent of commercial buildings in the Lower Mainland and 15 percent on Vancouver Island connect to district energy systems with the other regions in between.	FEI expert opinion to account for the 2017 LTGRP planning horizon and to simplify assumption in absence of conclusive updates to quantitative research.

49.2 To what extent are these assumptions based on factors such as: a significant uptake in electric heat pumps, regulations, price, incentives, or a switch back to electric resistance heating driven by much lower heating demand in new buildings?

Response:

Please refer to the response to BCSEA IR 2.49.1.

49.3 How have these assumptions changed since the 2014 LTGRP?

Response:

Please refer to the response to BCSEA IR 2.49.1.

50.0 Topic: Renewable Natural Gas

Reference: Exhibit B-1, section 2.4.2; Table 3-1; section 3.4.6; Figure 3-14: RNG Annual Demand Scenarios – All Sectors; section 5.3.1; section 8.2.4 RNG and other Innovative Natural Gas Technologies; Appendix E: Potential GHG Emissions Reductions Pathways; Exhibit B-3, FEI Response to BCSEA-SCBC IR 1.42.1

BCSEA-SCBC refer to: "Resource Supply Potential for Renewable Natural Gas in B.C., PUBLIC VERSION," MARCH 2017, by Hallbar Consulting Inc. and the Research Institute of Sweden (RISE), available at

https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/resource_supply_potential_for_renewable_natural_gas_in_bc_public_version.pdf ("Hallbar Report").

The Hallbar Report concludes in part:

> "In the short-term, achievable RNG production potential [in B.C.] is estimated to be up to 4.4 PJ/year." [pdf p.5]

The Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg. 102/2012, prescribes a renewable natural gas undertaking in section 2 (3.7) to (3.9) as follows:

> "2. (3.7) A public utility's undertaking that is in the class defined in subsection (3.8) is a prescribed undertaking for the purposes of section 18 of the [Clean Energy] Act.
>
> (3.8) The public utility acquires renewable natural gas
>
> (a) for which the public utility pays no more than $30 per GJ, and
>
> (b) that, subject to subsection (3.9), in a calendar year, does not exceed 5% of the total volume of natural gas provided by the public utility to its non-bypass customers in 2015.
>
> (3.9) The volume referred to in subsection (3.8) (b) does not include renewable natural gas acquired by the public utility that the public utility provides to a customer in accordance with a rate under which the full cost of the following is recovered from the customer:
>
> (a) the acquisition of the renewable natural gas;
>
> (b) the service related to the provision of the renewable natural gas." [underline added]

> "In its March 22, 2017, amendment to the [Greenhouse Gas Reduction (Clean Energy)] Regulation, the BC government also increased to $30/GJ the maximum rate at which FEI may acquire RNG. The amendment also enables FEI to acquire sufficient RNG to meet <u>up to 5 percent of FEI's 2015 non-bypass annual demand (this equals approximately 8.9 million GJ).</u>" [Exhibit B-1, pdf p.71]

50.1 Is FEI familiar with the Hallbar Report? Please file a copy of the report.

<u>Response:</u>

Yes. Please refer to Attachment 50.1 for a copy of the report specified by the URL in the question.

50.2 Please discuss the extent to which FEI's scenarios involving accelerated acquisition of RNG take into account (a) the Hallbar Report and (b) the GGR(CE) Regulation.

<u>Response:</u>

FEI referred to both the Hallbar report and the GGR(CE) regulation when developing its forecast.

There are three factors that FEI has considered which would dampen the total long range acquisition forecast.

1. The Hallbar report did not include the technical constraints on the distribution system that can occur in various locations throughout FEI's service territory, but rather simply examined proximity to the system. An example of a technical constraint might be that the RNG resource could be located in an area of the system where FEI may not be able to accept the full amount of produced biomethane due to the existing natural gas load on FEI's infrastructure in the immediate area.
2. The 2017 LTGRP RNG potential forecast recognizes that FEI does not have an unlimited institutional/operational capacity for adding incremental supply (e.g., internal resources to negotiate contracts, seek regulatory approvals, construct supply connections, ensure safety and quality, etc.).
3. FEI remains uncertain of the long term market (supplier or project developer) response to the higher available price enabled by the GGR(CE). To date, FEI has seen higher

interest from project developers but they remain cautious as they watch existing projects and evaluate their options.

50.3 Please confirm that three of FEI's five alternate future demand scenarios (Local Growth & Constricted Supply, Global Growth & Carbon Step Change, and Upper Bound), assume RNG demand in excess of 2.5 million GJ/year by 2025.

Response:

Not confirmed. Local Growth & Constricted Supply and Global Growth & Carbon Step Change RNG annual demand exceeds 2.5 million GJ/year in 2025. Upper Bound RNG annual demand exceeds 2.5 million GJ/year in 2026. The Live Spreadsheet Appendix B-5 of the Application contains annual demand forecast results for RNG for each year.

50.3.1 What steps is FEI taking to acquire these amounts of RNG?

Response:

Please refer to the response to BCUC IR 2.65.2.

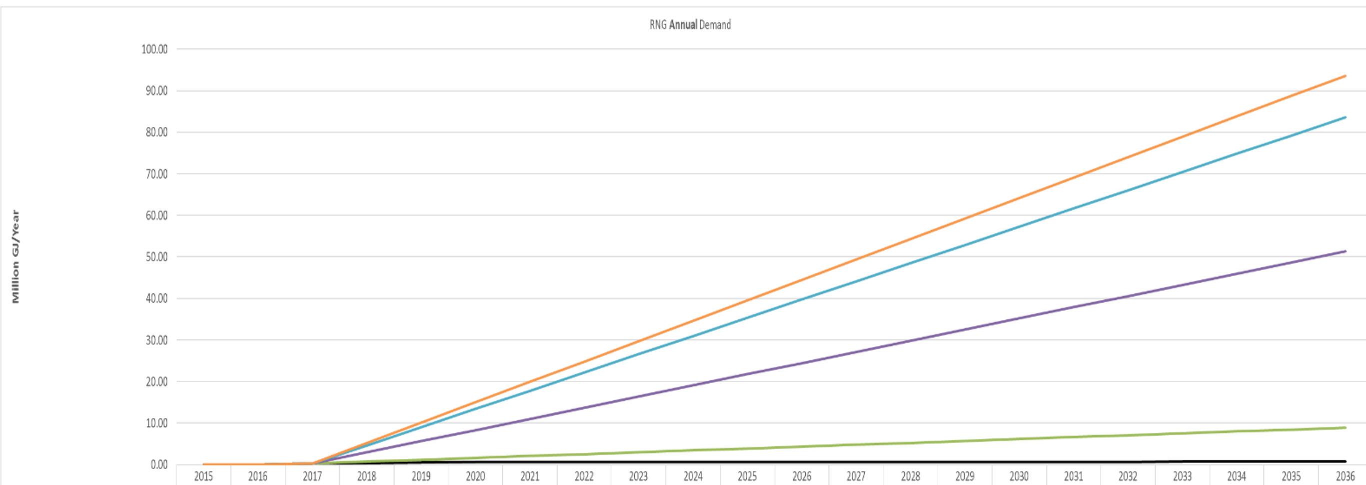
50.4 FEI's Reference Case forecasts RNG GHG emissions reductions of 0.04 MtCO2e over 2015 base [Exhibit B-1, Table 8-1, pdf p.231]. Please provide a graph and table showing how much RNG is this, in GJ/year, over each year of the planning period, along with the amount of RNG in the Reference Case, the amount of RNG contemplated in the four-year Action Plan, and the amount of RNG in each of the four speculative RNG pathways described in Appendix E and quantified in Table E-1.

Response:

The chart and integrated data table below display the RNG annual demand that underpins the Reference Case RNG GHG emissions reductions value in Table 8-1 of the Application and the speculative RNG results (under Reference Case conditions) in Table E-1 of the Application.

FEI notes that, within the 2017 LTGRP approach, the Reference Case values in the chart below denote a forecast, whereas the other values (associated with Appendix E of the Application) denote speculative results within the context of broadening assumptions beyond the analysis presented in the body of the 2017 LTGRP. As noted in Section 9 of the Application, the Action Plan describes the activities that FEI intends to pursue over the next four years. Pursuant to Order G-189-14, dated December 3, 2014, FEI confirms that it has built the Action Plan based on the Reference Case end-use annual demand forecast and the Traditional Peak Method forecast.

As discussed in the response to CEC IR 2.50.2, FEI has taken an approach that takes into account other factors beyond simply the total forecast amount of RNG available in BC.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reference Case Forecast	0.00	0.00	0.24	0.34	0.50	0.57	0.63	0.63	0.64	0.64	0.65	0.66	0.66	0.67	0.67	0.68	0.68	0.68	0.69	0.69	0.70	0.70
RNG at GGRR Cap (2036)	0.00	0.00	0.24	0.69	1.15	1.60	2.06	2.51	2.97	3.42	3.88	4.33	4.79	5.24	5.70	6.15	6.61	7.06	7.52	7.97	8.43	8.88
Cellulosic RNG at 51 million GJ (2036)	0.00	0.00	0.24	2.93	5.61	8.30	10.99	13.68	16.37	19.06	21.74	24.43	27.12	29.81	32.50	35.19	37.87	40.56	43.25	45.94	48.63	51.32
Cellulosic RNG at 84 million GJ (2036)	0.00	0.00	0.24	4.62	9.01	13.40	17.78	22.17	26.56	30.94	35.33	39.72	44.10	48.49	52.88	57.26	61.65	66.04	70.42	74.81	79.20	83.58
Cellulosic RNG at 94 million GJ (2036)	0.00	0.00	0.24	5.15	10.07	14.98	19.90	24.81	29.73	34.64	39.56	44.47	49.39	54.30	59.22	64.14	69.05	73.97	78.88	83.80	88.71	93.63

Reference Case Forecast — RNG at GGRR Cap (2036) — Cellulosic RNG at 51 million GJ (2036) — Cellulosic RNG at 84 million GJ (2036) — Cellulosic RNG at 94 million GJ (2036)

50.5 Is FEI confident that under the 2017 LTGRP Reference Case FEI will acquire and deliver enough RNG by 2036 to achieve GHG emissions reductions of 0.04 MtCO2e over 2015 base?

Response:

Yes. However, FEI notes that to reach that goal, there is an implied willingness on the part of RNG suppliers to develop new projects to supply RNG to FEI, and for customers to purchase RNG from FEI.

From a supply perspective, FEI cannot solely rely on its existing supply resources to deliver this amount of RNG; additional supply projects must be developed. In the event that suppliers do not continue to develop new projects, FEI may not be able to reach its full Reference Case forecast volume of RNG and therefore it may not reach annual emissions reductions equal to 0.04MtCO_2e by 2036.

From a consumer demand perspective, FEI assumes that the current drivers of RNG demand such as Provincial and Federal climate change policies and a general desire among private sector organizations and customers to address their GHG emissions remain largely in effect.

50.6 In Appendix E, FEI states: “This appendix assumes four speculative maximum RNG levels to be achieved by 2036. The first level assumes that FEI will reach its maximum allowance under the GGRR (5 percent of FEI’s 2015 non-bypass annual demand, or approximately 8.88 million GJ at up to $30 per GJ energy supply cost) by 2036.” [Exhibit B-1, pdf p.3468] Table E-1 shows forecast 2036 RNG at GGRR Cap at <u>0.5</u> MtCO2e over 2015 base. Please explain the difference between this figure and the figure of <u>0.4</u> MtCO2e over 2015 base in Table 8-1. Is the figure in Table 8-1 based on assuming that FEI acquires less than the 5% RNG Cap?

Response:

FEI interprets the question’s reference to Table 8-1 of the Application to enquire about the Reference Case Forecast Emissions Reductions in 2036 due to RNG. The Reference Case value (0.04 MtCO_2e) in Table 8-1 of the Application is derived from the 2036 Reference Case RNG annual demand value in Figure 3-13 (approximately 0.7 million GJ). In contrast, the 2036 value for “RNG at GGRR Cap” in Table E-1 (0.5 MtCO_2e) speculatively assumes that FEI will deliver approximately 8.88 million GJ of RNG by 2036.

50.7 In Appendix E, FEI states that "This appendix assumes four speculative maximum RNG levels to be achieved by 2036. The first level assumes that FEI will reach its maximum allowance under the GGRR (5 percent of FEI's 2015 non-bypass annual demand, or approximately 8.88 million GJ at up to $30 per GJ energy supply cost) by 2036." What changes in regulations would be required in order for FEI to achieve the first level (GGRR Cap) RNG pathway? Please address RNG supply using (a) current RNG supply technologies, and (b) cellulosic biogas.

<u>Response:</u>

With respect to (a) current RNG supply technologies, FEI has received feedback from existing agricultural RNG projects indicating that there are environmental regulations and permitting requirements in this area that may hamper development of projects. Some changes to these regulations and permitting requirements would help to accelerate development of agricultural RNG projects. An example would be changes which support the adoption of nutrient recovery/management technologies by farmers improving the economics for agricultural RNG supply projects.

With respect to (b) cellulosic biogas, FEI considers this technology to be developmental. There are no commercial-scale facilities running at this time. This technology will benefit from demonstration projects and additional funding to move it closer to commercialization.

51.0 Topic: Effect of net zero buildings on demand for natural gas

Reference: Exhibit B-1, section 2.3.3.1; section 3.4.4; Government Mandate Letter, Exhibit B-3, Attachment 33.1, pdf p.212

"The 2017 LTGRP's critical uncertainties break down as follows:

- Economic variables:
  - Economic growth, represented by account growth values in the forecast model;
  - Natural gas commodity price, based on a multitude of third-party forecasts (this accounts for price changes motivated by various factors, such as demand-supply balance or upstream regulatory changes);
- Policy variables:
  - Carbon price, which accounts for provincial and federal carbon pricing actions and is agnostic to the specific pricing mechanism (the forecast model simply assumes a stream of price values without identifying, for example, whether these are the result of a carbon tax or a cap and trade system);
  - <u>Non-price policy levers, which account for changes in the building code, energy performance standards</u>, and any requirements for switching from one fuel type to another (e.g. district energy systems); and
- The extraneous variables of RNG demand, NGT demand, and demand from large industrial point loads (FEI's scenario analysis assumes that the RNG and NGT markets are still emerging and thus primarily depend on policy and stakeholder action rather than other macroeconomic factors)." [Exhibit B-1, pdf pp. 94 – 95, underline added; footnote removed]

"The modeling process involved turning each of these assumptions into concrete changes to the input values for buildings in the three sectors. For example, in response to higher or lower gas prices, adjustments were made to the number of new buildings using natural gas for specific end-uses, or to the number of existing buildings whose owners might opt to change fuels when equipment needs replacement. The policy environment affects assumptions about the number of customers who would opt to install energy efficient equipment naturally, without influence from utility programs." (pdf p. 97)

The BC Climate Leadership Team recommended in Recommendation 20 that B.C. establish by 2016 a buildings strategy that by 2030 reduces greenhouse gas emissions from the buildings sector by 50 per cent.

The Climate Leadership Plan states that the B.C. Government is "implementing a number of policies to encourage the development of net zero buildings." [p.37, underline added]

The BC Energy Step Code, adopted in April 2017 as an amendment to the BC Building Code, is a performance-based code that can be adopted voluntarily by builders or imposed locally by municipalities. It "contains multiple steps for residential and commercial buildings that range from enhanced compliance with the prevailing provincial building code to net zero ready building performance." [Exhibit B-1, pdf p.73]

Various BC municipalities have adopted, or are considering adopting, a goal to supply 100 percent of their energy needs via clean and renewable sources by 2050.

In July 2016, the City of Vancouver released the Zero Emissions Building Plan that aims for all new buildings to achieve zero operational GHG emissions by 2030. FEI says:

> "The COV and FEI announced an agreement in November 2017, whereby the COV would amend the Zero Emissions Building Plan to include alternate compliance pathways that align with the BC Energy Step Code. This pathway does not require new buildings to achieve the GHGI [GHG intensity] target if they, instead, comply with a step of the BC Energy Step Code that achieves similar reductions in GHGs." [Exhibit B-1, pdf p.74]

FEI states further that:

> "Significantly reducing GHG emissions from new developments and new housing builds, and implementing an electrified transportation system, poses the risk of downward pressure on natural gas demand and could result in increased electricity demand in the COV." [Exhibit B-1, pdf p.74, underline added]

The July 18, 2017 mandate letter to the B.C. Minister of Environment and Climate Change Strategy includes separate sectoral reduction targets and plans within a new legislated 2030 GHG emissions reduction target. It states:

- "Implement a comprehensive climate-action strategy that provides a pathway for B.C. to prosper economically while meeting carbon pollution reduction targets, including setting a new legislated 2030 reduction target and establishing separate sectoral reduction targets and plans." [Exhibit B-3, pdf p.212, underline added]

BCSEA-SCBC are interested in the consequences for FEI's delivery charges of substantially reduced GHG emissions from the building section.

51.1 Please give more detail about FEI's 2017 agreement with CoV on the Zero Emissions Building Plan:

Response:

FEI and the CoV signed a Memorandum of Understanding (MOU) in the Fall of 2017 which identified eight action areas for both parties to work together. The CoV and FEI agreed to coordinate on actions relevant to the Zero Emission Building Plan (ZEBP) to ensure that builders in the CoV were able to access FEI's DSM incentives by adopting an alternate compliance pathway consistent with the BC Energy Step Code for CoV building energy policies that incorporate the ZEBP. So far, these policies include the Green Building Policy for Rezoning (GBPR) and the Vancouver Building By-Law (VBBL) Update for 7+ story residential and office, retail and hotel buildings. Builders who, in turn, choose the BC Energy Step Code pathway are eligible for FEI DSM incentives for the BC Energy Step Code for relevant residential and commercial buildings.

Changes to the VBBL and the GBPR were made at the May 2, 2018 CoV council meeting and FEI has rolled out its Step Code incentives to market as of April 2018.

Please refer to Attachment 51.1 for a copy of the MOU, and the CoV report to council.

51.1.1 Is this a formal agreement with reciprocal terms and conditions?

Response:

The document is a Memorandum of Understanding. Please refer to the response to BCSEA IR 2.51.1, Attachment 51.1 which contains a copy of the agreement.

51.1.2 Please give an example of an alternate compliance pathway that would "align with" or "comply with" the BC Energy Step Code without achieving a GHGI target.

Response:

FEI interprets the question to describe an example of an alternative step code pathway that does not have a GHGI target when compared to the current VBBL and rezoning building policy requirements. Please see the table below for an example where an alternate compliance pathway that aligns with a level of the BC Energy Step Code which does not have a GHGI target.

In addition, for new residential single-family housing less than 3500 sqft, the VBBL Zero Emissions Building Plan (ZEBP) Pathway provides a prescriptive compliance option with no GHGI limits for builders. This negates the need for an alternate compliance pathway for these buildings.

	Vancouver Building By-law		**Green Building Policy for Rezoning**	
	ZEBP Pathway	Step Code Pathway	ZEBP Pathway	Step Code Pathway
7+ Storey Residential	Part 3, Step 2 + **GHGI limit of 14**	Part 3, Step 3 (no GHG limit)	Part 3, Step 3 + **GHGI limit of 14**	Part 3, Step 4 (no GHG limit)

51.1.3 Please copy a copy of the agreement.

Response:

Please refer to the response to BCSEA IR 2.51.1.

51.2 Please provide more detail on how "non-price policy levers, which account for changes in the building code, energy performance standards …" are incorporated into the alternative future scenarios.

Response:

Section 1.2.1.4.1 of Appendix B-1 of the Application provides a detailed explanation of the Non-Price Carbon Policy Action critical uncertainty inputs. Section 1.1 of the same Appendix describes in detail how the 2017 LTGRP scenario analysis conceptualizes its critical uncertainties and Section 1.2.2 of the same Appendix provides a detailed description of how the critical uncertainties impact the 2017 LTGRP forecast model. FEI discussed this topic in detail with the Resource Planning Advisory Group during the April 11, 2017, workshop which BCSEA attended. The presentation slide deck and meeting summary for this workshop are available at the following location on FEI's website:

https://www.fortisbc.com/About/ProjectsPlanning/GasUtility/NatGasResourcePlanning/Pages/Stakeholder-engagement.aspx

51.3 Are increased building energy performance standards, such as net zero buildings, or a 50% reduction in GHG emissions from buildings by 2030, incorporated into any of the alternate future scenarios? If yes, which ones?

Response:

This response also addresses BCSEA IR 2.51.3.1.

As explained in Section 1.2.1.4.1 of Appendix B-1 of the Application, 2017 LTGRP scenarios that are subject to the Accelerated outcome on the Non-Price Carbon Policy critical uncertainty do include increased building energy performance standards, such as the performance requirements defined by the BC Energy Step Code (including Passive House and Net Zero Ready buildings). As outlined in Table 3-1 of the Application, these scenarios are Scenario B, Scenario C, and Scenario E. As further noted on page 2 of Appendix B-1 of the Application, the 2017 LTGRP scenario analysis intentionally determined critical uncertainty inputs before generating scenario plotlines and populating quantitative data in order to avoid inadvertently favoring certain visions of the future over others by presupposing scenario results (rather than focusing on the inputs). This means that the 2017 LTGRP end-use method annual demand scenarios are not targeted to achieve any specific GHG emissions reductions; rather, changes in GHG emissions due to changes in annual natural gas demand over the course of the planning horizon are a result of the scenario analysis.

Significantly reducing GHG emissions from existing and new developments in the building sector via factors such as provincial or municipal energy and emissions policy, could potentially result in downward pressure on natural gas demand. FEI interprets a 50 percent reduction in GHG emissions by 2030 (as referenced by the question) to be significant but FEI notes that no such target exists in current regulation or legislation. What is more, Appendix E of the Application outlines significant potential opportunities for GHG abatement via natural gas infrastructure and points out that emerging technologies, such as end-use carbon sequestration, may enable GHG abatement without changing the annual demand for natural gas.

FEI did not complete an alternate forecast scenario specific only to the BC building sector reducing GHG emissions by 50 percent by 2030 for the 2017 LTGRP. However, <u>under the</u>

<u>hypothetical assumption that a reduction in GHG emissions from the building sector were to be mirrored by an equal reduction in natural gas demand</u>, the directional effect on FEI's delivery rates as a result of reducing 50 percent of GHG emissions from the building sectors by 2030 can be estimated using the 20-year vision of FEI's delivery rate impact under the Lower Bound Scenario already available in Section 8.6 of the Application.

The BC building sector is mostly included in FEI's residential and commercial rate schedules, and based on the natural gas demand breakdowns provided in FEI's response to BCUC IR 1.27.1, the total residential and commercial natural gas demand in 2015 is 130.5 PJ (74.3 PJ from the residential sector and 56.2 PJ from the commercial sector, before C&EM savings and excluding NGT). Under the assumption that the 50 percent reduction in GHG emissions from the 2015 level is due to reducing natural gas demand from FEI's residential and commercial sectors by 50 percent as the question suggested, FEI's total natural gas demand in 2015 (191.7 PJ) would have to be reduced by approximately 65.3 PJ (130.5 PJ / 2) to become 126.4 PJ (191.7 PJ – 65.3 PJ). Under the Lower Bound scenario of the Application, the natural gas demand in 2033, before C&EM savings, is estimated to be 127.9 PJ, which closely approximates the 126.4 PJ required if the GHG emission from BC's building sector is reduced by 50 percent. Also, 2033 occurs only three years after the 2030 target year suggested in the question (please see Figure 4-1 [in table form] below with highlights added for 2015 and 2033 for the Lower Bound scenario).

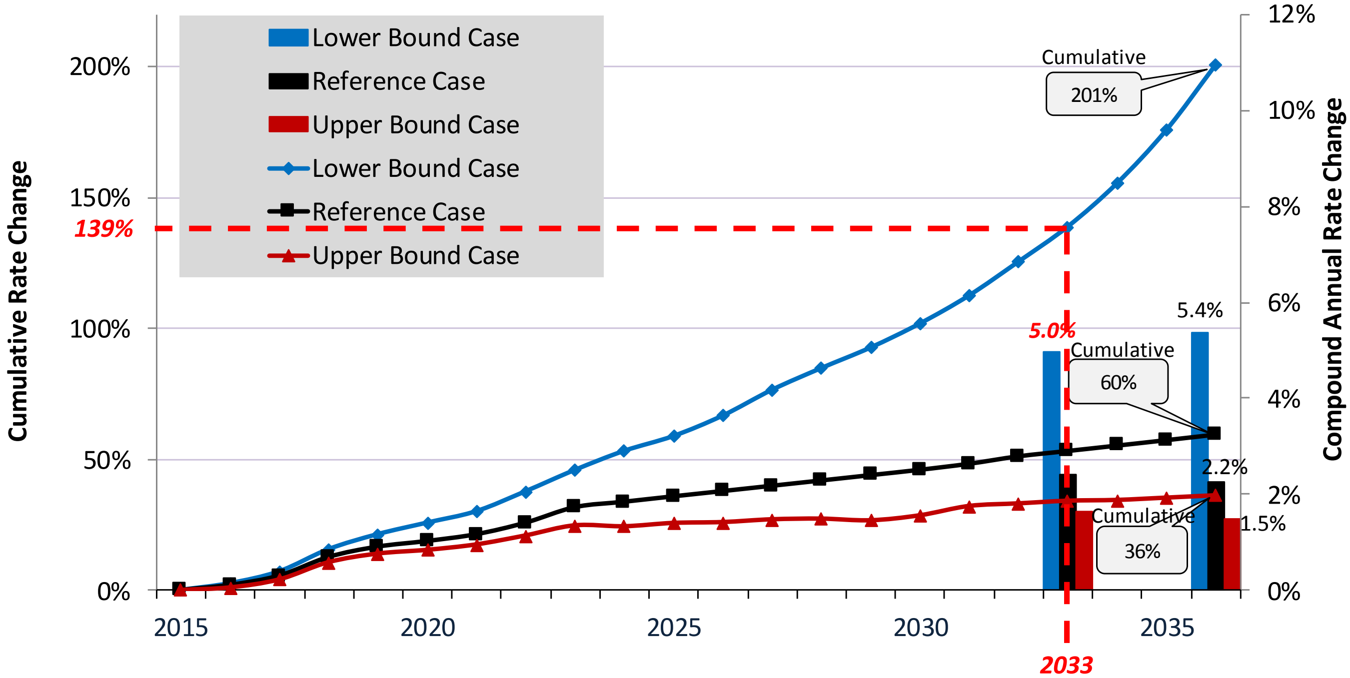
Using the Lower Bound scenario in year 2033 as a proxy, the projected cumulative and compound annual delivery rate impacts shown in Figure 8-7 of the Application are 139 percent and 5 percent, respectively (see Figure 8-7 reproduced below with highlights added to year 2033 showing the cumulative and compound annual rate impacts under the Lower Bound scenario). FEI believes using the rate impacts in year 2033 of the Lower Bound scenario is a reasonable estimation of the rate impact if a 50 percent reduction in natural gas demand (via a 50 percent reduction in GHG emissions) from the building sector were to occur by the year 2030. The directional indication of the rate impact will be identical, regardless of whether the 50 percent reduction in natural gas demand from the buildings sector were to occur in 2030 instead of year 2033.

Furthermore, given the similarity of the long-term natural gas demand profile between the Lower Bound scenario and the 50 percent reduction in natural gas demand from the building sector as suggested by this question, FEI considers that the infrastructure investment profile developed under the Lower Bound scenario can be applied to this question as well. Additionally, it is important to note, as discussed in FEI's response to BCSEA IR 1.3.1 and 1.23.1, that the impact on delivery rates due to changes in the volume throughput to the FEI system generally outweigh the impact due to accelerating/delaying infrastructure investments needed to meet the increased/decreased volume demand.

Figure 4-1 [in table form]: Natural Gas Demand Before and After Estimated C&EM Savings (Excluding NGT) – All Sectors (GJ)

1

Year	Reference Case		Upper Bound		Lower Bound	
	Scenario Annual Demand	Scenario Annual Demand after C&EM	Scenario Annual Demand	Scenario Annual Demand after C&EM	Scenario Annual Demand	Scenario Annual Demand after C&EM
2015	191,738,754	191,738,754	191,738,754	191,738,754	191,738,754	191,738,754
2016	192,012,307	192,012,307	193,846,528	193,846,528	190,790,190	190,790,190
2017	192,240,096	190,972,506	194,937,321	193,693,609	189,440,809	188,177,491
2018	192,642,932	190,381,325	196,107,170	193,865,184	187,872,246	185,653,232
2019	192,899,700	189,756,975	197,381,162	194,277,583	185,665,523	182,665,192
2020	193,249,740	189,231,616	198,907,946	194,918,677	182,834,472	179,056,197
2021	193,684,523	188,683,463	200,731,952	195,916,765	180,649,174	176,043,999
2022	194,132,108	188,180,033	202,762,816	197,137,720	176,332,630	171,019,760
2023	194,569,468	187,627,264	204,456,431	198,031,931	173,551,747	167,620,667
2024	194,986,558	187,113,721	208,396,291	201,182,673	168,317,967	161,989,505
2025	195,438,057	186,709,699	210,175,286	202,099,348	165,282,019	158,528,562
2026	195,991,649	186,436,275	214,282,556	205,386,984	160,637,333	153,548,783
2027	196,529,588	186,159,585	216,202,447	206,495,979	155,205,948	147,841,981
2028	197,104,356	185,933,929	219,530,560	208,523,659	151,927,610	144,298,555
2029	197,678,086	185,722,290	224,420,566	212,620,716	148,215,489	140,375,732
2030	198,275,517	185,516,567	226,551,514	213,907,688	143,920,345	135,931,574
2031	198,916,020	185,442,364	228,788,433	215,387,216	138,988,173	131,029,971
2032	199,560,318	185,536,754	231,019,146	217,042,572	133,268,039	125,504,032
2033	200,219,329	185,691,187	233,551,659	218,787,862	127,937,693	120,406,439
2034	200,901,688	185,885,236	236,786,010	221,466,815	121,876,858	114,665,485
2035	201,585,020	186,092,500	239,031,438	223,175,225	115,410,562	108,557,101
2036	202,261,704	186,312,636	241,245,597	224,859,327	107,595,062	101,228,368



51.3.1 If no, please provide a table showing a quantitative estimate of the reduction in Reference Case demand at 2030 that would represent downward pressure on natural gas demand due to significantly reducing GHG emissions from existing and new developments in the buildings sector and the corresponding impact on delivery rates (all else equal). Use an upper and lower range of demand reductions if suitable.

Response:

Please refer to the response to BCSEA IR 2.51.3.

51.4 Is the estimated percentage reduction in natural gas use roughly the same as a given target percentage reduction in the GHG emissions of BC's building stock? Are fossil fuels other than natural gas, i.e., heating oil, a significant factor in BC?

Response:

Please refer to the response to BCSEA IR 2.51.3 for the first part of the question.

With respect to fossil fuels other than natural gas, FEI does not have any information on the effects of reduction targets on those fuel sources.

51.5 Please provide an rough estimate of the effect on FEI's delivery rates of a 50% reduction in GHG emissions from BC's buildings sector by 2030, assuming a straight-line or slightly accelerating rate of reductions.

Response:

Please refer to the response to BCSEA IR 2.51.3.

51.5.1 Please discuss what effect such a reduction in demand would have on FEI's infrastructure investments.

Response:

Please refer to the response to BCSEA IR 2.51.3.

52.0 Topic: Delivery Rates

Reference: Exhibit B-1, section 2.3.3.1; Government Mandate Letter, Exhibit B-3, Attachment 33.1, pdf p.212

The BC Climate Leadership Team recommended in Recommendation 20 that B.C. establish by 2016 a buildings strategy that by 2030 reduces greenhouse gas emissions from the buildings sector by 50 per cent.

The Climate Leadership Plan states that the B.C. Government is "implementing a number of policies to encourage the development of <u>net zero buildings</u>." [p.37, underline added]

The BC Energy Step Code, adopted in April 2017 as an amendment to the BC Building Code, is a performance-based code that can be adopted voluntarily by builders or imposed locally by municipalities. It "contains multiple steps for residential and commercial buildings that range from enhanced compliance with the prevailing provincial building code to net zero ready building performance." [Exhibit B-1, pdf p.73]

Various BC municipalities have adopted, or are considering adopting, a goal to supply 100 percent of their energy needs via clean and renewable sources by 2050.

In July 2016, the City of Vancouver released the Zero Emissions Building Plan that aims for all new buildings to achieve zero operational GHG emissions by 2030. FEI says:

> "The COV and FEI announced an agreement in November 2017, whereby the COV would amend the Zero Emissions Building Plan to include alternate compliance pathways that align with the BC Energy Step Code. This pathway does not require new buildings to achieve the GHGI [GHG intensity] target if they, instead, comply with a step of the BC Energy Step Code that achieves similar reductions in GHGs." [Exhibit B-1, pdf p.74]

FEI states further that:

> "<u>Significantly reducing GHG emissions from new developments and new housing builds, and implementing an electrified transportation system, poses the risk of downward pressure on natural gas demand</u> and could result in increased electricity demand in the COV." [Exhibit B-1, pdf p.74, underline added]

The July 18, 2017 mandate letter to the B.C. Minister of Environment and Climate Change Strategy includes separate sectoral reduction targets and plans within a new legislated 2030 GHG emissions reduction target. It states:

- "Implement a comprehensive climate-action strategy that provides a pathway for B.C. to prosper economically while meeting carbon pollution reduction targets, including setting a new legislated 2030 reduction target and establishing separate sectoral reduction targets and plans." [Exhibit B-3, pdf p.212, underline added]

BCSEA-SCBC are interested in the consequences for FEI's delivery charges of substantially reduced GHG emissions from the building section.

52.1 Please provide a table showing a quantitative estimate of the reduction in Reference Case demand at 2030 that would represent downward pressure on natural gas demand due to significantly reducing GHG emissions from existing and new developments in the buildings sector and the corresponding impact on delivery rates (all else equal). Use an upper and lower range of demand reductions if suitable.

Response:

Please refer to the response to BCSEA IR 2.51.3.

53.0 Topic: DSM Depth of Savings

Reference: Exhibit B-2, FEI Response to BCUC 1.27.3

In BCUC IR 1. 27.3, the Commission asked:

> "27.3 Please compare FEI's expected energy savings to the annual savings targets and 2030 reduction in energy demand summarized for EERS states. Please discuss the differences."

FEI responded:

> "As indicated by the values provided in the response to BCUC IR 1.27.2, <u>the 2017 LTGRP C&EM analysis annual and cumulative energy savings as a percentage of sales results are lower than the respective values discussed in the EERS</u> on pages 35 and 36 of Exhibit B-1. The policy framework by which FEI achieves savings through its C&EM programs is different than in jurisdictions that use an EERS. FEI is enabled to pursue any cost-effective savings from C&EM program spending, meaning generally that FEI's volume of saved energy is predicated on the cost of C&EM programs relative to the cost of energy. This differs from <u>the general approach of an EERS which typically mandates savings as a percentage of sales</u>. Utilities operating under an EERS are obliged to pursue the most cost-effective pathway to achieve those savings. The differences between these two systems is that FEI optimizes the total savings it can achieve in its C&EM activities under the cost-effectiveness constraint while utilities under an EERS are mandated a total volume of savings and are optimizing on the costs to achieve those savings. As such, FEI's volume of energy savings targets depends on assumptions like the price of energy and the costs of C&EM interventions. Under an EERS, the volume of savings is more certain while the costs to achieve those savings programs are variable." [pdf p.118]

53.1 How do FEI's expected DSM energy savings targets over the plan period and at 2030, as a percentage of annual sales, compare with those of natural gas distribution utilities in jurisdictions that do not use an EERS?

<u>Response:</u>

An industry review conducted by E Source (an energy industry analytics consultancy) was only able to pull information on this topic for the utilities listed in the table below and only for the years 2018 through 2020 (sales data is limited to 2016). Energy savings forecasts beyond these years were not available.

Note that the forecast energy savings represented here are not necessarily targets but simply the energy savings forecast to be achieved.

As indicated in the table below, FEI has approximately the same expected DSM energy savings percentage of annual sales as NIPSCO and a larger percentage than NW Natural. The other utilities listed have larger percentages.

FEI cannot at this time say how closely each of these values is directly comparable to the FEI values in terms of calculation method and inputs, nor the jurisdictional and other differences that might account for the variation seen in this table.

Non EERS States	Gas Utilities from These States	2018 Forecast Energy Savings/2016 Sales	2019 Forecast Energy Savings/2016 Sales	2020 Forecast Energy Savings/2016 Sales	# of Customers
ID	Avista	3.66%	N/A	N/A	129,477
IN	NIPSCO	0.53%	N/A	N/A	465,930
UT	Questar Gas Company	6.35%	N/A	N/A	900,000
VA	Washington Gas Light[1]	8.61%	9.03%	N/A	1,000,000
WY	Black Hills (and other states)	3.90%	3.90%	3.90%	36,000
WA	Puget Sound Energy[2]	3.07%	3.07%	N/A	1,119,695
OR	NW Natural	0.26%	N/A	N/A	700,000
FortisBC Energy Inc.		0.52%	0.46%	0.46%	995,082

Notes:
"N/A" means insufficient data was available to complete the percentage calculation
All FEI data pertains to the 2017 LTGRP Reference Case
Energy savings are annual unless otherwise noted
1. Energy savings are lifetime (not annual) values
2. Energy savings were available for 2018 and 2019 combined; FEI assumed this combined value evenly splits into 2018 and 2019

54.0 Topic: DSM expenditure schedule

Reference: Exhibit B-3, FEI-BSEA 1.24.1

"FEI expects to file its 2019 – 2022 DSM Expenditures application during Q2, 2018, in order to attain a timely Commission approval for its 2019 expenditures."

54.1 What is the current expected timing of filing the 2019-2022 DSM Expenditure Schedule?

Response:

FEI expects to file its 2019-2022 DSM Expenditures Schedule application by end of June 2018.

55.0 Topic: Connect to Gas Program

Reference: Exhibit B-3, FEI-BCSEA 1.30.3; Exhibit B-1, section 8.3 GHG Emissions Forecasts, pdf p.226

BCSEA-SCBC asked FEI:

> "30.3 Please confirm, or otherwise explain, that "Connect to Gas" (formerly "Switch 'n' Shrink") supports only measures that reduce GHG emissions.

FEI responded:

> "In 2012, the "Switch 'n' Shrink" program budget was moved from C&EM (then EEC) to O&M per Commission Order G-44-12.
>
> FEI confirms that the previous "Switch and Shrink" program, now an offering that is run under the "Connect to Gas" umbrella, continues to provide customers with rebate incentives that support the reduction of GHG emissions.
>
> The overarching "Connect to Gas" initiative is a branding umbrella under which FEI communicates to customers about becoming a gas customer as opposed to one specific program. Since the rebranding, <u>FEI has expanded its efforts to additional offerings</u>. Under the umbrella, FEI will continue to develop and pilot rebate and other offerings to meet customer needs and demands." [Exhibit B-3, FEI Response to BCSEA-SCBC 1.30.3, underline added]
>
> "The BCUC has requested FEI to discuss the relationship between demand and GHG emissions within its 20-year vision. The BCUC also identified as part of a 20-year vision a discussion of FEI's contribution to BC's GHG targets. Outlined in Part 1(2) of the province's CEA, BC's energy objectives include taking demand side measures to conserve energy, encouraging efficient energy use, fostering the development in BC of innovative technologies that support energy conservation and efficiency, encouraging switching from one kind of energy to another that decreases provincial GHG emissions, and reducing BC's GHG emissions. FEI's C&EM activities, NGT initiative, RNG offering and <u>Connect to Gas Program are all important activities that help to meet these goals</u>." [Exhibit B-1, pdf p.226, underline added]

55.1 Please confirm, or otherwise explain, that the overarching "Connect to Gas" initiative includes offerings that increase GHG emissions.

<u>Response:</u>

This response also addresses BCSEA IRs 2.55.2 and 2.55.3.

The current primary offering in the Connect to Gas overarching umbrella are the incentives for customers to switch from other energy sources (oil, or propane) to a high efficient natural gas heating system which reduces GHG emissions (this offering is similar to the “Switch and Shrink” program). Under the Connect to Gas umbrella there is also a rebate available for the installation of natural gas wall furnaces. Depending on the homeowners’ other heating appliances this program can decrease GHG emissions. Both of these offerings also include a top up offering for high efficient on demand water heaters which would also result in lower emissions. There are no other offers currently available under the Connect to Gas umbrella.

55.2 What are the offerings under the “Connect to Gas” initiative that increase GHG emissions?

Response:

Please refer to the response to BCSEA IR 2.55.1.

55.3 What is the name of the component of the “Connect to Gas” initiative that was formerly called “Shrink ‘n’ Switch”?

Response:

Please refer to the response to BCSEA IR 2.55.1.

55.4 Does FEI anticipate that the component of the “Connect to Gas” initiative that was formerly called “Switch ‘n’ Shrink” will continue throughout the planning period?

Response:

Yes, as noted in the response to BCSEA IR 1.30.6, FEI anticipates that the component of the "Connect to Gas" initiative that was formerly called "Switch 'n' Shrink" will continue so long as there are offerings available for customers, customers are participating in the offerings and the message resonates with customers.

55.5 Please provide, for the most recent available year, the spending the component of the "Connect to Gas" initiative that was formerly called "Switch 'n' Shrink," the spending on the "Connect to Gas" initiative, and the percentage.

Response:

Approximately 90 percent of the "Connect to Gas" incentive spending to date has been on the initiative that was formerly called "Switch 'n' Shrink".

55.6 If the "Connect to Gas" initiative includes components that would increase GHG emissions, then please explain how the Connect to Gas Program supports the B.C, energy objectives.

Response:

The activities under the Connect to Gas umbrella are funded through O&M as part of the PBR approvals. Broadly speaking, the intent of the efforts of the Connect to Gas umbrella are to encourage customers to attach to the gas system. At present, the two offerings under the Connect to Gas umbrella are an offering encouraging customers to switch to natural gas from another energy form such as oil, propane or wood, and a supplemental heating offering for wall furnaces. In both cases, the switch to natural gas can lower GHG emissions and therefore is consistent with the BC Energy Objectives. In addition, these customers can participate in the RNG program which would further reduce emissions.

56.0 Topic: NGT GHG emission reductions

Reference: Exhibit B-3, FEI Response to BCSEA IR 1.36.1, pdf p.93

"For example, natural gas used to displace liquid transport fuels would reduce net lifecycle GHG emissions by approximately 30 percent."

56.1 Please provide the source of this information. The figure does not appear to coincide with the figures from GHGenius v4.03 cited in FEI's response to BCSEA-SCBC IR 1.36.2 [pdf p.95].

<u>Response:</u>

The response to BCSEA IR 1.36.1 contains a typographical error. FEI indicated a value of 30 percent but the correct value should be 20 percent. The response to BCSEA IR 1.36.1 has been corrected in the erratum being filed concurrently. The peer reviewed and published analysis by Peng et al. (2017) estimated lifecycle GHG emissions of vehicle fuel pathways in China.[1] Refer to Attachment 56.1 for a copy of the article. Based on the LNG 1 scenario which assumes imported LNG deliveries for fueling trucks within a 100 km proximity of the destination of import, the lifecycle GHG emission reductions would be 19 percent. However, this scenario used a high-level average of carbon intensity for LNG production. Using the lifecycle GHG analysis of LNG in BC conducted by Globe Advisors (2014), LNG from BC is approximately 25 percent less GHG intensive than an estimated global average. Please refer to Attachment 56.1 for a copy of the 2014 BC LNG GHG Life Cycle Analysis Discussion Draft. Translating this gain to the upstream GHG component in Peng et al. would see lifecycle GHG reductions of approximately 24 percent in heavy duty trucks compared to the diesel fuel pathway.

[1] Peng, T.; Zhou, S.; Yuan, Z.; Ou, X. Life Cycle Greenhouse Gas Analysis of Multiple Vehicle Fuel Pathways in China. Sustainability 2017, 9, 2183.

57.0 Topic: NGT GHG emission reductions – GHGenius v4.03

Reference: Exhibit B-1, pdf pp.229, 3460; Exhibit B-3, FEI Response to BCSEA IR 1.36.2, pdf p.93

> "NGT emissions reduction factors are sourced from GHGenius. RNG and C&EM emissions factors are sourced from the BC Ministry of Environment & Climate Change Strategy." [footnote 155, pdf p.229, underline added]

> "Calculation based on GHGenius model found at http://www.ghgenius.com/. The GHGenius model is based on Canadian fuel and supply sources." [footnote 2, pdf p.3460, underline added]

> "GHGenius v4.03, a Canadian lifecycle GHG emissions assessment tool, concludes that natural gas has the lowest lifecycle GHG emissions compared to all other fossil fuels in all sectors in BC. On a fuel-cycle basis: ..." [Exhibit G-3, FEI Response to BCSEA-SCBC IR 1.36.2, underline added]

57.1 Please confirm, or otherwise explain, that FEI relies on GHGenius for NGT GHG emissions reduction factors and lifecycle GHG emissions results.

Response:

FEI confirms that the 2017 LTGRP relies on the carbon intensity factors for NGT GHG emissions abatement calculations as approved and accepted by the BC Ministry of Energy and Mines. Footnote 155 of the Application indicates that the factors are sourced from GHGenius because FEI understands that the BC Ministry of Energy and Mines uses inputs from GHGenius in accepting and ultimately approving carbon intensities of various transportation fuels.

57.2 Please confirm, or otherwise explain, that GHGenius v4.03 was issued publicly in June 2013 and is the most recent version.

Response:

The GHGenius webpage has version 4.03 currently available for download to users.[2] FEI cannot comment on the date this version was made available or whether v4.03 is the most recent version.

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[2] https://ghgenius.ca/about.php.

57.3 What is the date of the data contained in GHGenius v4.03 on which the NGT GHG emissions reduction factors and lifecycle GHG emissions results are based?

Response:

FEI is not aware of the date of the data contained in GHGenius v4.03. The Ministry of Energy and Mines and/or GHGenius would be better positioned to provide input to this inquiry.

57.4 Are FEI's NGT GHG emissions reduction factors and lifecycle GHG emissions results based on up-to-date data?

Response:

FEI's NGT GHG emissions reduction factors and lifecycle GHG emissions results are based on the current carbon intensity figures as accepted and approved by the Ministry of Energy and Mines.

57.5 What source does FEI rely on for estimates of GHG emissions reduction factors for marine transportation?

Response:

In the analysis provided in the 2017 LTGRP, FEI did not have access to the carbon intensity of marine fuels and thus FEI used the currently approved carbon intensity for diesel fuel as a proxy for marine transportation fuel. FEI feels this is reasonable because the vast majority of maritime fuel currently consumed in the world today has a higher carbon intensity than diesel fuel because marine vessels that operate outside the Emission Control Areas (ECA) typically consume intermediate fuel oil or heavy fuel oil. These two fuels are not as refined as diesel fuel and thus have a higher carbon intensity than diesel fuel.

If anything, the GHG emissions reductions from marine transportation presented in FEI's 2017 LTGRP are understated as a result of using the carbon intensity of diesel fuel rather than intermediate or heavy fuel oil.

58.0 Topic: International Marine NGT

Reference: Exhibit B-1, footnote 12, pdf p. 30; pdf p. 22; pdf p. 71; pdf p. 80. section 2.3.3.5; pdf p. 46, pdf p. 78; pdf pp. 106 – 107; pdf pp. 110 - 111.

> "NGT includes CNG and LNG supply for heavy duty on-road trucks, locomotives, marine vessels, mine haul trucks and remote power generation for industrial applications." [Exhibit B-1, footnote 12, pdf p.30, underline added]

> "FEI examined NGT market capture scenarios of between 1 and 15 percent of the heavy duty and return to base fleet vehicles, and uses a Reference Case expectation of 4 percent market capture. All market sectors of potential NGT future demand - land transportation CNG and LNG vehicles as well as coastal freight vessels, domestic passenger ferries, locomotives, mine haul trucks and stationary power generation for industrial applications - are important in helping the Province meet its carbon emission reduction targets. The trans-Pacific marine segment, however, has the most significant potential impact on increased natural gas demand combined with reduced carbon emissions." [Exhibit B-1, pdf p.22, underline added]

> "The GGRR is designed to facilitate certain market segments to adopt natural gas as a transportation (or power generation) fuel to displace higher carbon emitting fuels such as diesel and heavy marine oil." [Exhibit B-1, pdf p.71]

> "The Provincial GHG emissions inventory (in Section 2.4.1) includes only marine emissions for vessels transiting intercoastal provincial waterways. Marine vessels that regularly call BC ports that originate from ports of other countries (i.e. container ships, chemical tankers, car carriers, etc.) are not included in the Provincial emissions inventory, although these vessels emit large amounts of GHGs into the Province's atmosphere when in transit, and when berthed in domestic ports. It is FEI's view that these emissions should be considered as part of a global GHG reduction strategy through fuel switching from the incumbent petroleum marine fuels to natural gas." [Exhibit B-1, pdf p.80

BCSEA-SCBC wish to learn more about the relationship between the "vessels transiting intercoastal provincial waterways" and the "trans-Pacific marine segment" components of the marine component of FEI's NGT (Natural Gas for Transportation) initiatives.

58.1 Please confirm, or otherwise explain, that GHG emissions that are not included in BC's GHG emissions inventory are not included in Canada's and BC's GHG emissions reductions targets.

Response:

GHG emissions from vessels on international routes are not included in BC or Canada's GHG emissions inventory per FEI's response to BCSEA IR 1.37.6.

It should be noted that in April 2018, the Marine Environment Protection Committee (MEPC) of the International Marine Organization (IMO) adopted an initial strategy on the reduction of GHG emissions from ships which outlines a vision to reduce GHG emissions from international shipping by 50 percent from 2008 levels by 2050. It is expected that the MEPC will begin developing legally binding measures (as it has done to develop regulations to implement the Energy Efficiency Design Index for example) to achieve this target. Under the MARPOL Convention (to which Canada is a signatory), countries develop national legislation to enter the convention into the force of law. So, while the GHG emissions from international shipping may not appear in Canada's (or any country's) national inventory, Canada may need to execute strategies and policies to address this key source of GHG emissions in the coming years.

58.2 Is it the case that all GHG emissions from vessels transiting intercoastal provincial waterways are <u>included</u> in the BC GHG emissions inventory and all GHG emissions from vessels calling BC ports from international ports are <u>excluded</u> from the BC GHG emissions inventory?

Response:

Yes, that is FEI's understanding of the BC GHG emissions inventory.

58.2.1 Please confirm, or otherwise explain, that GHG emissions from ships engaged in international transit are excluded from the BC GHG emissions inventory even when such GHG emissions occur while the vessel is within BC waters.

Response:

Confirmed.

58.3 In section 2.3.3.5, BC Government Directions to BCUC, of the Application, FEI discusses BC government orders in council 557/2013, 749/2014, OIC 162/2017, 100/2017 and 101/2017. To the extent that these directions apply to investments by FEI regarding LNG facilities that could be used for the marine component of NGT, in FEI's view are these directions limited to LNG facilities to serve intercoastal provincial shipping or do they apply to LNG facilities that might serve a future international shipping market for LNG bunkering?

Response:

In FEI's view, these directions are not limited to LNG facilities to serve intercoastal provincial shipping exclusively, but also apply to LNG facilities that will serve the international market for LNG bunkering, intercoastal provincial shipping and potentially any other market segment that would use LNG as a fuel.

Additionally, regardless of the end use of the LNG that could be provided from FEI's LNG facilities, the development of a robust LNG market in BC would yield reduction in GHG emissions through expanded use of natural gas displacing more carbon intensive fuels.

58.4 When FEI uses the term Natural Gas for Transportation as including LNG (or CNG) for marine vessels does the term include LNG for international marine shipping?

Response:

Confirmed, the term does include LNG for international marine shipping.

> "Capitalizing on the LNG marine bunkering opportunity is a key part of FEI's strategy to leverage pre-existing Company-owned assets and operational expertise to drive growth in new markets. While the Tilbury LNG facility primarily serves as a winter peaking facility, over time, the facility has also evolved to serve a variety of new LNG markets. Tilbury is a scalable LNG facility that, subject to any required regulatory approvals and the lead time for obtaining them, provides FEI with the flexibility to invest in new infrastructure in order to capitalize on load growth opportunities such as the marine bunkering market." [Exhibit B-1, pdf p.78, underline added]

58.5 In FEI's view, is there any distinction between the intercoastal component and the international component of the marine bunkering market in terms of the approvals FEI has or would require in order to serve this market?

Response:

Given that FEI sells LNG Free on Board (FOB) from the Tilbury LNG Facility, the approvals that FEI may require are not distinguished between the intercoastal and international components.

58.6 What approvals would FEI require from the BCUC in order to invest in, and operate, facilities to provide LNG bunkering for the international shipping market? What would trigger a requirement for such an approval?

Response:

Currently FEI has approvals under the following pieces of regulation to undertake further expansions of the Tilbury LNG Facility (Phase 1B) and to enable the adoption of lower carbon transportation fuels generally:

- Direction No. 5 (Order in Council (OIC) No. 557 (B.C. Reg. 245/2013) dated November 27, 2013 and further amended by OIC 749 (B.C. Reg. 265/2014) dated December 19, 2014 and OIC No. 162 (B.C. Reg. 115/2017) dated March 21, 2017) to undertake a further expansion of the Tilbury LNG Facility (Phase 1B) per the conditions contained in Direction No. 5;
- Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) approved via OIC 295 (B.C. Reg. 102/2012) dated May 15, 2012 to enable the adoption of natural gas as a transportation fuel to displace higher carbon fuel sources, and further amended by OICs:
    - 609 (B.C. Reg. 214/2016) dated August 19, 2016;

- 161 (B.C. Reg. 114/2017) dated March 21, 2017; and
- 199 (B.C. Reg. 84/2018) dated April 20, 2018.

Commission approval would not be required for FEI to proceed with the Phase 1B expansion of the Tilbury LNG facility. It should be noted that these pieces of regulation enable the provision of LNG FOB Tilbury and that the end use of that LNG is not specified in the regulations.

58.7 What additional facilities and pipeline capacity would FEI need to construct to serve an international marine shipping market with LNG?

<u>Response:</u>

Initially, no additional FEI facilities or pipeline capacity would be required and moreover, the relatively constant year-round nature of the bunkering demand would result in more efficient use of existing FEI pipeline capacity. As the market grows, the pipeline and facility requirements will depend on the location(s) at which the LNG facilities to serve the demand are installed within the FEI transmission systems as well as the total demand at each location.

It is difficult to speculate on the specific capacity expansion requirements until location and demand requirements have been determined. Table 6-3 on page 174 of the Application can be used as a guide and identifies some example system expansion scenarios that could serve an international marine market with LNG. Expansion Scenario 1 shows that the current configuration of the CTS which includes the CTS Project that entered service in 2017 has the capacity to support up to 264 TJ/d in demand in the South Delta/Richmond region which includes the Tilbury LNG facility.

The Table also illustrates how the capacity to serve the South Delta/Richmond area might be reduced if a large industrial load was also added to the Vancouver Island Transmission System (VITS). In the example in Table 6-3 a demand of 260 TJ/d on the VITS was used to demonstrate the effect on delivery capability to the South Delta/Richmond area. The addition of 260 TJ/d to the VITS reduces the delivery to the South Delta/Richmond area by 166 TJ/d.

The Tilbury 1A expansion, when fully contracted, will require approximately 38.5 TJ/d of the delivery available in the South Delta/Richmond area. The current CTS therefore has the pipeline capacity to deliver to the South Delta/Richmond area the difference of at least an additional 59.5 TJ/d and up to 225.5 TJ/d to the Tilbury facility or any other 3rd Party facility location or combination of locations in the South Delta/Richmond region. The higher delivery volumes would be available only if there was no other large LNG or other industrial demand added at other locations in the VITS or similarly other regions of the CTS. Liquefaction capacity above the current 38.5 TJ/d would also need to be installed to utilize the available pipeline capacity.

In a future that aligns with the High forecast with LNG presented in Figures 6-11 and Figure 6-13, it is estimated that the existing CTS would require expansion by 2024/25 and by 2023/24 if there was additional demand on the VITS as well. The contribution of the transpacific marine market was estimated to increase dramatically after 2022 in the High forecast which amounts to increases from 38 TJ/d in 2022 to 134TJ/d in 2023/24 and to 265 TJ/d in 2024/25. The scope of additional capacity expansion required at that time should such a forecast materialize could be similar to those pipeline and compression expansions described in Table 6-3 in the LTGRP along with the associated liquefaction and storage facilities, but could vary depending on the circumstances that exist as the market develops.

> "Natural gas as a transportation fuel has emerged as a growing market in BC, both for CNG and LNG customers. As discussed in Section 2, <u>the Company has established programs (incentive and infrastructure investment opportunities) that are enabled through the BC government's GGRR to assist customers with</u>:
>
> o <u>Incentives toward the incremental cost of new natural gas vehicles (which includes marine vessels</u>, mine haul trucks, on-road trucks, buses and locomotives) and remote power generation applications;" [Exhibit B-1, pdf pp.106-107, underline added]

58.8 Does FEI provide, or have any plans to provide, incentives under the GGRR toward the incremental cost of new natural gas marine vessels for the <u>international</u> marine shipping sector?

<u>Response:</u>

The Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) currently allows public utilities in BC to provide grants or incentives for non-BC based companies. This is in recognition that many international marine companies do not have head offices or operations strictly based in BC, and thus the GGRR permits the issuance of grants and incentives to non-BC based companies.

As a result, FEI does intend to provide incentives to the coastal freight and international (trans-Pacific) marine market for those vessels that regularly call the Port of Vancouver. With the International Maritime Organization (IMO) imposing regulations on the amount of sulphur permitted in marine fuel coming into effect 2020, FEI does expect international shipping companies to consider LNG as a marine fuel. Offering incentives may tip the decision of these companies to consider the Port of Vancouver as their hub for LNG fueling.

FEI would ensure contractual mechanisms are in place to manage the risk associated with providing incentives to non-BC based shipping customers, as FEI does with all of its current customers that have received incentives from FEI. For example, FEI would look at the creditworthiness of the customer entering into a grant or incentive agreement with FEI, requiring sufficient security be posted prior to incentives issued, the length of term FEI would require in exchange for the incentives and other options that could be considered to manage and reduce risk.

> "For the High forecast scenario, FEI further built upon the Base scenario but incorporated a more aggressive LNG adoption scenario, <u>particularly from the trans-Pacific deep sea marine segment</u>. <u>In both the Base and High scenarios, the marine segment plays a crucial role in developing LNG demand on a material scale, beyond the capacity of the Tilbury Phase 1A Expansion</u>.
>
> For example, if LNG gains prominence as a maritime fuel and vessels begin to request LNG bunkers from West Coast ports, <u>the High scenario assumes that in addition to the key marine segment identified in the Base case, other marine segments would also adopt LNG on a larger scale. For instance, LNG adoption for container marine vessels was not included in the Base scenario but is included in the High scenario.</u>" [Exhibit B-1, pdf pp.110-111, underline added]

58.9 In its approach to including LNG for marine service in the annual demand scenarios does FEI make any distinction between LNG for marine service where the ship source GHG emissions reductions are <u>included</u> versus <u>excluded</u> from the BC GHG emissions inventory and Canadian or BC GHG emissions reductions targets?

<u>Response:</u>

The end-use annual demand forecast scenarios presented in the body of the 2017 LTGRP do not distinguish between LNG for marine service where the ship source GHG emissions reductions are included versus excluded from the BC GHG emissions inventory and Canadian or BC GHG emissions reductions targets. Appendix E of the Application presents potential GHG emissions reduction pathways. In this appendix to the Application, FEI does separately display GHG reduction potential of natural gas in the domestic and international transport sectors. Under Reference Case conditions, Appendix E estimates that natural gas in domestic and international transport would reduce 0.3 and 1.9 Mt of CO_2e from 2015 levels in 2036, respectively. Under the Global Growth & Carbon Step Change scenario, these values increase to 0.5 and 14.4 Mt of CO_2e, respectively. To illustrate the magnitude of this emissions abatement opportunity and as noted in Section 8.3.2 of the Application, 2014 BC economy-wide GHG emissions totalled 64.5 Mt of CO_2e.

As stated in the responses to BCSEA IRs 1.37.5 and 1.37.6, emissions from international marine shipping are not included in any one country's emissions inventories. As this source of emissions is still sizeable, at approximately 1 billion tonnes of CO_2 equivalent, it will require concentrated actions to reduce emissions to achieve the newly developed IMO target of a 50 percent reduction in GHG emissions by 2050.[3]

[3] http://www.imo.org/en/, direct link: http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Documents/Third%20Greenhouse%20Gas%20Study/GHG3%20Executive%20Summary%20and%20Report.pdf

59.0 Topic: GHGs from International Marine Shipping

Reference: Exhibit B-2, FEI response to BCUC IR 45.1, pdf pp 194-5

The Commission asked FEI to provide a version of Table 8-1 which excludes NGT GHG emissions reductions that are realized outside the current boundaries of the BC emissions inventory. FEI provided a revised Table 8-1. FEI also provided the following text:

> "Limiting the scope of GHG reductions to BC's boundaries significantly reduces the scale of GHG emissions reductions from British Columbia's natural gas transport solutions. This is because the largest potential for GHG reductions in transportation exists in the international marine sector which is not included in either of Canada's or BC's GHG emissions inventory. GHG emissions from the international marine sector are responsible for approximately 3 percent of total global GHG emissions or 1 billion tonnes of CO2e. However, the emissions associated with this sector are not accounted for in any one country's national GHG inventory. If the international marine sector was considered a country, it would be the 6th largest global emitter of GHG emissions. The vast majority of fossil fuel consumption from ships into BC ports are from international shippers on trans-pacific routes. <u>It is estimated that the emissions associated with international marine shipping into and out of BC ports are on the same order as BC's total domestic GHG emissions.</u>" [underline added; footnote removed]
>
> <u>In the upper bound scenario, the GHG emissions reductions associated with the conversion and adoption of LNG-powered international marine vessels are over 20% of BC's total domestic GHG emissions. In other words, actions in the international marine sector alone would be enough to move BC one quarter of the way to achieve its 2050 emissions reductions target of 80% below 2007 levels.</u>
>
> The International Marine Organization announced that it was, for the first time, adopting GHG emissions targets consistent with the goals of the Paris Agreement. The IMO aims to reduce carbon emissions by 50 percent compared with 2008 levels by 2050. Based on analysis from the International Energy Agency (which informed the IMO's target-making) low carbon fuels including LNG make up the second-largest GHG emission reducing action needed to achieve this target.
>
> The table below excludes NGT emissions reductions that are realized outside the boundaries of the BC emissions inventory by excluding international marine shipping emissions, specifically this excludes emissions estimated from the coastal freight and trans-pacific marine market segments. The emissions from both of these market segments are not captured in BC's emissions inventory.

However, marine vessels bunkered with LNG from BC represents a sizeable opportunity to reduce net global GHG emissions. BC's LNG sector has a number of factors that make it very low emissions intensity compared to other jurisdictions, including its colder climate, low formation CO2 gas in the Montney gas basin, and a clean power grid powering electrified LNG plants such as at FEI's Tilbury LNG facility." [underline added]

59.1 Please confirm, or otherwise explain, that FEI is not saying that GHG emissions reductions due to the substitution of LNG for higher-carbon intensity fuels used by international marine ships that call on BC ports and are provided with LNG bunkering by FEI would literally count toward BC's GHG emissions reduction target even though such emissions are not included in the BC GHG emissions inventory.

Response:

FEI is not claiming nor advocating nor recommending that GHG emissions reductions due to the substitution of LNG for higher-carbon intensity fuels used by international marine ships that call on BC ports, and that are provided with LNG bunkering by FEI should count toward BC's GHG emissions reduction target.

However, as stated in responses to BCSEA IRs 1.37.6 and 2.58.9, emissions from the maritime sector are sizeable and will require a concerted effort to help this market segment transition toward a lower GHG fuel as GHG emission reduction strategies are developed and implemented on this sector.

60.0 Topic: GHG Emissions

Reference: Exhibit B-3, FEI Response to BCSEA-SCBC IR 1.36.1; 1.36.3; Exhibit B-1, p.31, pfd p.68

> "The IEA conducted a detailed review of the scale of fugitive methane emissions around the world and estimated that there was a global average 1.7 percent leakage rate for natural gas across the supply chain.[13] This is further supported by calculations completed by FEI using data from the BC Ministry of Environment at which upstream and transmission/distribution vented, flared and fugitive emission was compared to the total amount of marketable gas produced in BC. Based upon 2015 values, the estimated methane leakage rate for natural gas in BC is 0.5 percent." [Exhibit B-3, pdf p.94, underline added]

> "The 2015 estimated methane leakage rate in BC is 0.5 percent, well below the world average. This is consistent [with] a review conducted by FEI based on vented, flared, and fugitive data for upstream producers and transmission pipeline companies as published by the BC Ministry of Environment." [Exhibit B-3, pdf p.96, underline added]

> "The CLP [BC Climate Leadership Plan] included the following actions which, if implemented, may impact FEI and provincial natural gas use patterns: ...
>
> - Pursuing multiple pathways for reducing the emissions intensity of natural gas:
>   - Introducing regulation and an incentive program to reduce upstream vented and fugitive methane emissions by 45 percent by 2025;" [Exhibit B-1, p.31, pfd p.68, underline added]

> "In early 2017, ECCC plans to propose federal methane regulations for the oil and gas sector, which will reduce emissions of methane – a potent greenhouse gas – by 40 to 45 percent from 2012 levels by 2025. These regulations are designed to deliver on commitments made at the North American Leaders Summit and through the Canada-United States Joint Statement on Climate, Energy and Arctic Leadership." [GOVERNMENT OF CANADA RESPONSE TO THE STANDING COMMITTEE ON NATURAL RESOURCES' INTERIM REPORT: "THE FUTURE OF CANADA'S OIL AND GAS SECTOR: INNOVATION, SUSTAINABLE SOLUTIONS AND ECONOMIC OPPORTUNITIES" January 19, 2017, Exhibit B-1, Appendix D, pdf p.619, underline added]

An Environment and Climate Change Canada "Technical Backgrounder: Federal methane regulations for the upstream oil and gas sector," dated April 27, 2018 and located at https://www.canada.ca/en/environment-climate-change/news/2018/04/federal-methane-regulations-for-the-upstream-oil-and-gas-sector.html, states:

> "As part of the Pan-Canadian Framework on Clean Growth and Climate Change, the Government of Canada reaffirmed its commitment to reduce methane emissions from the oil and gas sector by 40 to 45 percent from 2012 levels by 2025. Methane is a potent greenhouse gas (GHG) that is 25 times more powerful than carbon dioxide and methane emissions make up about 15 percent of Canada's total GHG emissions. The oil and gas sector is the largest contributor to methane emissions in Canada.
>
> In April 2018, Environment and Climate Change Canada (ECCC) published federal methane regulations to deliver on this commitment. ECCC has consulted extensively with provinces, territories, industry, environmental organizations and Indigenous peoples to develop robust and cost-effective regulations." [underline added]

A May 2018 report by Maximilian Kniewasser for the Pembina Institute titled "Limiting methane pollution from B.C.'s gas sector A prime opportunity for stronger action on upstream emissions," (Kniewasser Report) at http://www.pembina.org/reports/BC-Methane-Emissions-2018.pdf, states:

> "Stronger action to reduce methane pollution from British Columbia's natural gas sector and prospective liquefied natural gas (LNG) industry is essential to meeting B.C.'s climate targets.
>
> Methane emissions represent one of the most effective and cost-efficient opportunities to reduce carbon pollution in support of meeting climate targets for B.C.'s industrial sector. Current regulations to reduce methane emissions by 45% are estimated to cost just \$1.70/t-CO_2e. This suggests more cost-effective opportunities remain...
>
> Fulfilling the B.C. government's commitment to balance LNG development with B.C.'s climate targets will require increasing ambition on methane emissions. Ambition should reflect best practices and the government's commitment to price fugitive emissions." [p.1, underline added]

60.1 Please clarify whether the 2015 estimated methane leakage rate in BC of 0.5 percent is separate but confirmed by FEI's calculations, or the 0.5 percent estimate is simply the result of FEI's calculations. In any event, please provide a copy of FEI's review and, if there is one, the other source of the 0.5 percent estimate.

Response:

The 2015 methane leakage rate in BC of 0.5 percent was estimated by aggregating publicly available information from various Government of BC websites. The following table summarizes the various sources of information:

Data	Name of Source	Link to Source
Total Amount of Marketable Gas Produced in BC	BC Government – Natural Gas & Oil Statistics	https://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/statistics
Flared and Vented Gathering Systems (BC Plants only)	BC Government – Natural Gas & Oil Statistics	https://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/statistics
Flared and Vented Plants (BC plants only)	BC Government – Natural Gas & Oil Statistics	https://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/statistics
GHG Emissions – Total Vented and Fugitive Volumes (Linear Facilities Ops – Spectra Energy Midstream Corporation, Spectra Energy Transmission)	BC Government – Industrial Facility Greenhouse Gas Emissions	https://www2.gov.bc.ca/gov/content/environment/climate-change/data/industrial-facility-ghg
GHG Emissions – Total Vented and Fugitive Volumes (Linear Facilities Ops – FortisBC Energy Inc.)	BC Government – Industrial Facility Greenhouse Gas Emissions	https://www2.gov.bc.ca/gov/content/environment/climate-change/data/industrial-facility-ghg

60.2 Please describe in more detail how FEI's estimates methane leakage rates. Does it include any *in situ* measurements?

Response:

FEI follows the BC Ministry of Environment, Reporting Industrial Greenhouse Gas Emissions requirements which requires reporting operations to use the specific or approved methodologies from the Western Climate Initiative in quantifying GHG emissions. This includes fugitive related emissions which is completed through leak detection surveys (in-situ measurement) for FEI's compressor and LNG stations. Please refer to the response to BCSEA IR 2.60.1 for an explanation of how FEI estimated the 2015 methane leakage rate in BC.

60.3 Please describe briefly the current state of the federal and provincial regulation of methane emissions reductions applicable to the natural gas sector in B.C.

Response:

FEI is not directly involved in the development of federal and provincial methane regulations. For more information on industry perspectives on methane regulations please contact the Canadian Association of Petroleum Producers and the Canadian Gas Association.

60.4 Does the Reference Case in the 2017 LGTRP take into account federal and B.C. regulatory initiatives to substantially reduce methane emissions from the natural gas sector in B.C.? If so, in what way? If not, why not?

Response:

FEI considered federal and provincial regulatory initiatives towards the reduction of methane emissions when preparing the 2017 LTGRP. However, FEI relies on published carbon intensity data from the BC Government (such as the data described in FEI's response to BCSEA IR 2.57.1) to develop the GHG emissions estimates presented in the Reference Case.

60.5 How does FEI's 2015 estimate of a 0.5 percent methane leakage rate for the B.C. natural gas supply chain compare with the estimates of methane leakage used in the federal methane reduction regulatory initiative?

Response:

FEI has not performed any comparison between the federal methane reduction regulatory initiative and the 0.5 percent leakage estimate. FEI prepared the estimate of 0.5 percent methane leakage rate for the BC natural gas supply chain in response to BCSEA IR 1.36.3 and, to date, has not used this information for any other purposes.

60.6 Is FEI familiar with the Kniewasser Report? Please file a copy.

Response:

Please refer to Attachment 60.6 for a copy of the requested report. FEI is aware of the document as a result of the BCSEA request to file it. FEI is not otherwise familiar with it.

60.7 Does FEI agree that methane emissions represent one of the most effective and cost-efficient opportunities to reduce carbon pollution in support of meeting climate targets for B.C.'s industrial sector?

Response:

FEI interprets this request to ask if FEI agrees with the findings of the "Kniewasser" report that BCSEA requested FEI to file in response to BCSEA IR 2.60.6. The document speaks for itself. FEI has no comment and takes no position with regard to the opinions expressed in the report.

61.0 Topic: DSM and System Capacity Constraints

Reference: Exhibit B-3 FEI Response to BCSEA-SCBC IR 1.4.4; 1.4.5; 1.5.3; 1.23.3.

"FEI agrees that DSM can be used as a resource option to address system constraints. Practically, however, FEI cannot confirm that DSM programs are reducing peak demand to the extent that they can address system constraints." [pdf p.9]

"FEI agrees in principle that, with sufficient verification to support its effectiveness, a load-shifting DSM program could be used to address system constraints." [pdf p.10]

"FEI has not conducted analysis addressing above Plan DSM to address any of VITS, CTS or ITS constraints for reasons described in the response to BCUC IR 1.29.1. <u>FEI is developing the means to conduct such an analysis</u>." [pdf pp. 11-12, underline added]

"…FEI would consider infrastructure investment as a firm resource in the context of resource planning for addressing peak demand capacity constraints. To assess whether or not demand side measures are truly having a firm impact on peak demand and what economic value could be attributed to that impact would require <u>direct measurement of end-use loads at a reading frequency (hourly for example) sufficient to identify the peak end use consumption trends</u>." [pdf p.63, underline added]

"FEI believes that <u>many years</u> will be required to establish the measurement solutions and develop the end-use method to a point where a reliable determination of the impacts of DSM on peak demand projections and capacity related infrastructure investments can be made." [pdf p.64, underline added]

61.1 Please describe the steps that FEI is taking in "developing the means to conduct such an analysis [of above-Plan DSM to address VITS, CTS or ITS constraints]."

<u>Response:</u>

FEI interprets this as a request to describe the steps that FEI is taking to better understand the impact of end-use trends on peak demand, since FEI's response to BCUC IR 1.29.1 (also referred to in FEI's response to BCSEA IR 1.5.3 cited in the preamble) explains why there is no evidence that "above-Plan DSM to address VITS, CTS or ITS constraints" exists.

As stated in the response to BCSEA IR 1.5.3, FEI intends to continue to explore means to verify the model [referring to the exploratory peak end-use peak demand method] results and refine the inputs to the method with the objective of creating a reliable tool for analysis and prediction. Please refer to the responses to BCUC IRs 2.64.1, 2.64.1.1 and 2.64.1.1.1 regarding critical information needed to better analyze peak demand trends and additional activities to acquire such information.

61.2 Please provide the estimated date by which FEI's plan for conducting such an analysis will be complete and available for stakeholder review.

Response:

The development of a plan for acquiring the data needed to better analyze the impact of end use trends on peak demand is ongoing as there are many uncertainties impacting the analysis that needs to be done and the time it will take to complete them. Consequently, FEI is unable to provide an estimated date for completion at this time. Please refer to the responses to BCUC IRs 2.64.1 and 2.64.1.1 for further discussion.

61.3 Please provide FEI's estimated timeline for implementing its analysis plan.

Response:

Please refer to the response to BCSEA IR 2.61.2.

61.4 Does FEI anticipate requiring any approvals of the BCUC in order to implement its plan?

Response:

FEI has not yet determined if any BCUC approvals might be required for the work needed to fully develop an understanding of the impact of current and future end-use trends on peak demand. Please refer to the responses to BCUC IRs 2.64.1, 2.64.2 and 2.64.3 for further discussion.

61.5 What does FEI mean, specifically, by the term "many years" as used above?

Response:

FEI expects that implementation of the activities needed to better understand the impact of current and future end use trends on peak demand cannot occur over the course of a single year or two. Activities including assessing measurement solution technologies, which is currently underway, followed by acquiring hardware and installing the appropriate measurement infrastructure in sufficient numbers to generate useful baseline data, and further assessing impacts of various DSM activities would need to be completed. Analysis, once measurement solutions are established, would require data from multiple peak demand periods likely spanning at least several years to establish trends in consumption that FEI could use for planning purposes. Please also refer to the responses to BCUC IRs 2.64.1, 2.64.1.1 and 2.64.1.1.1.

61.6 Does FEI anticipate seeking BCUC approval for any growth-related infrastructure investments prior to the completion of its plan?

Response:

FEI currently forecasts that the Interior Transmission System will require a capacity upgrade by 2022 (page 176 of the 2017 LTGRP – Exhibit B-1). FEI intends to submit a CPCN application with sufficient lead time to receive approval and complete construction in advance of the constraint. This CPCN submission would occur prior to a time where methods capable of forecasting changes in peak demand as a result of DSM have been developed tested, and fully implemented.

61.7 If the BCUC were to require FEI to develop and implement such a plan on an expedited basis, when would FEI estimate that the results of "direct measurement of end-use loads" as required for the analysis could be completed?

Response:

FEI is working expeditiously within its current available resources and data sources to develop a means of assessing end-use influences on peak demand. Any implementation timeline would depend on the overall scope of any requirements requested by the Commission. Please refer to the responses to BCUC IRs 2.64.1, 2.64.1.1 and 64.1.1.1 for additional discussion on the further action and timelines FEI believes are required to implement any programs.

62.0 Topic: BC Conservation Potential Review

Reference: Exhibit B-3 FEI Response to BCSEA-SCBC IR 1.17.1; 1.17.1.2; 1.18.1; 1.18.3.

"…As such, the 2017 LTGRP incorporates all economic (i.e. cost-effective) demand-side measure activity" [pdf p.37]

"Uptake of cost-effective measures is influenced by factors that fall outside pure economics. Customer behaviour, either naturally or as influenced by program activity, is more complex than a financial calculation. Accordingly, 2017 LTGRP C&EM analysis forecast market potential energy savings were informed by BC CPR results and FEI's C&EM program experience." [pdf pp.37-38]

"As informed by the BC CPR results and FEI's program experience, the 2017 LTGRP C&EM analysis results display a theoretical estimate of energy savings measure uptake in relation to the ratio between incentive levels and measure incremental cost. This estimate takes into account program experience and technology diffusion but <u>does not take into account operational program delivery factors</u>." [pdf p.39, underline added]

"Market potential represented the cost-effective addressable potential that C&EM programs could pursue, while recognizing constraints imposed by likely market conditions (e.g., equipment turnover rates, incentive levels, consumer willingness to adopt, etc.). Since this analysis does not consider specific program design or delivery mechanisms, one cannot conclude that actual C&EM programs will, in practice, necessarily capture this addressable potential. For this reason, FEI uses the term market potential rather than the term achievable potential used by previous CPRs. <u>The analysis relied on customer willingness to adopt to determine the percentage of installations implementing an efficient measure versus a non-efficient measure</u>. Customer willingness to adopt was a function of modelled customer awareness and economic attractiveness of each measure. As a result, efficient measures that had low customer willingness to adopt, despite being economic from a TRC/MTRC perspective, did not appear in the reported results for market potential, though they were considered in the analysis." [pdf pp.40-41, underline added]

"The market potential represents a high-level assessment of savings that could be achieved over time, factoring in broader assumptions about customer acceptance and adoption rates that are not dependent on a particular program design. As such, <u>the BC CPR did not seek to optimize program design.</u>" [underline added]

"The initial market potential estimates for CPR measures that had not been offered historically relied on the CPR consultant's benchmarking of similar offerings in other jurisdictions. Since the CPR's market potential was not intended to represent "program" potential, the <u>study excludes considerations of measure-by-measure incentive levels and program delivery mechanisms</u>. [underline added]

62.1 Is FEI saying that the Market Potential savings represent the total of cost-effective savings <u>that can be achieved through programs</u>?

<u>Response:</u>

FEI consulted with Navigant Consulting Ltd. (Navigant) to provide the following response.

Market Potential refers to the cost-effective potential available under assumptions about market condition constraints (equipment turnover rates, incentive levels, consumer willingness to adopt, etc.) that are applied consistently across measures. Program Potential, on the other hand, assesses the potential from "mapping" measures to programs and using program-specific designs, incentive levels, or administrative costs. As noted previously in FEI's response to BCSEA IR 1.18.1, Market Potential provides a directional long-term view of addressable potential that can be pursued by programs. Thus, Market Potential provides a starting point for understanding which measures might provide the greatest value and savings through targeted programs.

62.2 Is the Market Potential savings included in the 2017 LTGRP equivalent to the commonly used term "Maximum Achievable Savings"? Please explain.

<u>Response:</u>

FEI consulted with Navigant to provide the following response.

No. "Maximum Achievable Savings" potential generally involves incentives that represent 100 percent of the incremental cost of energy efficient measures above baseline measures, combined with high administrative and marketing costs,[4] and represents a theoretical maximum for program potential. The Market Potential savings included in the 2017 LTGRP C&EM analysis, on the other hand, take into account constraints imposed by market conditions (equipment turnover rates, incentive levels, consumer willingness to adopt, etc.).

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[4] Rohmund, Ingrid et.al., Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010 – 2030), 2008 ACEEE Summer Study on Energy Efficiency in Buildings, https://aceee.org/files/proceedings/2008/data/papers/5_297.pdf.

62.3 The "BC CPR did not seek to optimize program design." Why not?

Response:

FEI consulted with Navigant to provide the following response.

FEI interprets "optimize program design" to mean creating programs by examining program delivery considerations, non-program non-incentive expenditures and emerging technologies (as listed in bullet points on pages 106 and 107 of the Application), and considering whether to bundle measures where appropriate. As such, FEI does not interpret this phrase to confer any value or performance judgement (i.e., sub-optimal versus optimal).

The BC CPR did not seek to optimize program design, given that the scope of the BC CPR was to conduct a long-term forecast, rather than a program design exercise. The BC CPR did not apply further "mapping" of measures to programs, or using program-specific designs, incentive levels or administrative costs. Rather, the intent of the BC CPR was to estimate the savings likely to be achieved under a common (i.e., across all measures) and standardized assumption regarding incentive level strategy and administrative costs.

62.3.1 Would it be helpful for FEI to understand how much cost-effective savings it could obtain through optimized programs, rather than basing estimates on historic results?

Response:

FEI consulted with Navigant to provide the following response.

As noted in the response to BCSEA IR 2.62.3, FEI does not interpret the phrase "optimized programs" to confer any value or performance judgement. FEI, in its DSM plan expenditure schedules, does develop program forecasts which estimate how much cost-effective savings it could obtain.

Also, as noted previously in the response to BCSEA IR 1.18.3, the method used in the BC CPR does not limit potential based on historic results. Historic results inform the initial market potential estimates for the first year of the forecast horizon, in terms of current market saturation and customer awareness. Beyond that, the economic attractiveness of the measure and the well-documented dynamics of technology diffusion drive the adoption of measures.

62.4 Is it FEI's position that "a reasonable assessment of cost-effective savings" is equivalent to the maximum cost-effective savings that can be achieved through optimized program designs?

Response:

FEI consulted with Navigant to provide the following response.

FEI assumes that the question's reference to "a reasonable assessment of cost-effective savings" pertains to FEI's response to BCSEA IR 1.18.3. In its response to BCSEA IR 1.18.3, FEI explains that BC CPR economic potential and market potential results provide "a reasonable assessment of cost-effective savings potential".

As noted in this response, the BC CPR market potential is based on a comprehensive, peer-reviewed collection of C&EM measures that, if they pass the applicable cost effectiveness test, are subjected to forecast customer willingness to adopt which, in turn, is grounded in observed market behavior. FEI is not familiar with the term "maximum cost-effective savings" but assumes in the context of this question that it is interchangeable with the term "maximum achievable savings" referenced in BCSEA IR 2.62.2. Please refer to the responses to BCSEA IRs 2.62.2 and 2.62.3 for how FEI interprets the terms "maximum achievable savings" and "optimized program designs". Given the interpretations that FEI explains in the responses to BCSEA IRs 2.62.2 and 2.62.3, "a reasonable assessment of cost-effective savings" (i.e., the outcome of a reasonable long-term forecasting process) cannot be equated with "maximum achievable savings" (i.e., theoretical maximum program potential without considering constraints other than measure-level cost effectiveness) that "can be achieved through optimized program designs" (i.e., the outcome of program design).

63.0 Topic: Future C&EM expenditure schedules and program design

Reference: Exhibit B-3 FEI Response to BCSEA-SCBC IR 1.21.5.

"FEI could reasonably attempt to capture additional cost-effective energy savings but such planning would occur in its future C&EM expenditure schedules and program design, which consider incentive levels, program delivery methods, and marketing." [pdf p.57]

"As explained in lines 8 – 10 of page 122, Figure 4-13 indicates that the "Highest Incentive" scenario—having aggregate incentives that are 44% higher than the "Baseline Incentive" scenario—results in 2035 annual savings that are 34% higher than the "Baseline Incentive" scenario." [pdf p.59, underline added]

63.1 Please explain how FEI determines how much more savings it could reasonably attempt to achieve if the program potential savings as determined in the BC CPR does not incorporate optimized program designs?

Response:

FEI consulted with Navigant to provide the following response.

Please refer to the response to BCSEA IR 2.62.3 for FEI's interpretation of "optimized program design".

Directionally, the BC CPR's long range forecast and sensitivity analysis indicate that higher incentive levels will likely lead to higher customer participation. However, those higher incentive levels may be more aggressive than the median incentive levels seen throughout North American utilities. Additionally, the sensitivity analysis shows that there is a diminishing rate of acquired savings per dollar of incentive spending. Thus, the BC CPR's sensitivity analysis shows that higher savings could be achieved, but those savings levels are not necessarily a suitable target for meeting the FEI's overarching programmatic goals in terms of cost effectively acquiring savings.

During program design (i.e., outside of the long-range forecasting activities), FEI's C&EM team can take this information into account when considering program-specific delivery factors. FEI's C&EM team would also consider the most recent market research to re-evaluate the expected consumer response from incentive levels and delivery mechanisms, and the team would weigh the relative merits of various program spending allocation strategies.

63.1.1 What criteria would FEI use to determine the amount of additional savings it could attempt to capture?

Response:

FEI consulted with Navigant to provide the following response.

The legislation outlined in the DSM Regulation is the criteria that FEI uses to determine how much savings it can capture with DSM programming.

As detailed in FEI's response to BCSEA IR 2.62.4, there is no indication that the BC CPR's market potential forecast is biased (either upward or downward) relative to a program planning forecast relying on similar aggregate-level incentive and administrative spending levels. As such, the BC CPR's sensitivity analysis on incentive levels provides a directionally reasonable forecast of savings that could be acquired with higher incentive spending. During the program design and C&EM planning phases, program planners would consider additional factors—that are more detailed than those included in the long-range forecasts—when forecasting expected savings.

63.1.2 What criteria would FEI use to determine the amount of additional savings it would propose to capture?

Response:

FEI consulted with Navigant to provide the following response.

As stated in in the response to BCSEA IR 2.63.1.1, the legislation outlined in the DSM Regulation is the criteria that FEI uses to determine how much savings it can capture with DSM programming.

The BC CPR's market potential forecast provides a long-range estimate of savings that could be achieved under reasonable incentive and administrative spending levels, while being agnostic to program design. Program design and planning activities, which were not in the scope of the BC CPR or the 2017 LTGRP C&EM analysis, will inform the proposed DSM expenditure plan program plans.

Attachment 47.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 50.1

Resource Supply Potential for Renewable Natural Gas in B.C.

PUBLIC VERSION

MARCH 2017

HÅLLBAR CONSULTING

Prepared by

This report was researched and written by Hallbar Consulting Inc. (www.HallbarConsulting.com) and the Research Institute of Sweden (RISE) (http://www.ri.se/en).

Prepared for

This report was prepared for and funded by the Province of British Columbia, FortisBC Inc., and Pacific Northern Gas Ltd.

For more information on this report, please contact the Electricity and Alternative Energy Division, BC Ministry of Energy and Mines.

Abbreviations and Acronyms

AD	Anaerobic Digestion
B.C.	British Columbia
BOD	Biochemical Oxygen Demand
CCS	Census Consolidated Subdivision
CH_4	Methane
DLC	Demolition, Land-clearing and Construction
GHG	Greenhouse Gas
GJ	Gigajoule
ICI	Industrial, Commercial and Institutional
Kg	Kilogram
Km	Kilometer
l	Litre
LFG	Landfill gas
Nm^3	Cubic metre
NRCan	Natural Resources Canada
ODT	Oven Dry Tonnes
PJ	Petajoule (one million GJs)
RI.SE	Research Institute of Sweden
RNG	Renewable Natural Gas
SSO	Source Separated Organic
TSA	Timber Supply Area
WAS	Waste Activated Sludge
WWTP	Wastewater Treatment Plant

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1. Executive Summary

Renewable Natural Gas (RNG) production potential in B.C. was assessed under short and long-term scenarios. The short-term scenario is defined as the next few years in which little change is expected regarding RNG feedstock and technology. The long-term scenario is defined as a date in the future where significant changes in RNG feedstock and technology are expected (the year 2035 was chosen). For the long-term scenario RNG production was assessed twice; first using only projected increased feedstock availability, second using projected increased feedstock availability and assuming significant advancements in wood RNG technology.

Within the short-term, theoretical RNG production potential is estimated to be up to 7.6 PJ/year. However, theoretical RNG production potential is the maximum amount of RNG that could be produced using the most favourable assumptions. Theoretical RNG production potential doesn't take into account certain realities, such as potential feedstock unavailability, or less than 100% capacity production at AD plants. Achievable RNG production potential is the amount of RNG that could be produced using realistic assumptions. In the short-term, achievable RNG production potential is estimated to be up to 4.4 PJ/year.

Long-term achievable RNG production potential, using projected increased feedstock availability and assuming no significant technology advancements, is estimated to be up to 11.9 PJ/year. Long-term achievable RNG production potential, using increased projected feedstock availability and assuming significant advancements in wood RNG technology, is estimated to be up to 93.6 PJ/year; this estimation depends heavily upon the assumed availability of forestry feedstock.

It should be noted that short and long-term RNG production potentials are total amounts of RNG that could be produced based on available feedstocks and RNG technology, and assuming a maximum RNG purchase price of $28/GJ. RNG production potentials therefore do not estimate total amount of RNG that could be produced at lower price points (i.e., $16/GJ or $20/GJ). As such, actual RNG production in B.C., which will depend heavily upon the market price for RNG, may be lower.

Figure 1: RNG Production Potential without Technology Advancements at $28/GJ

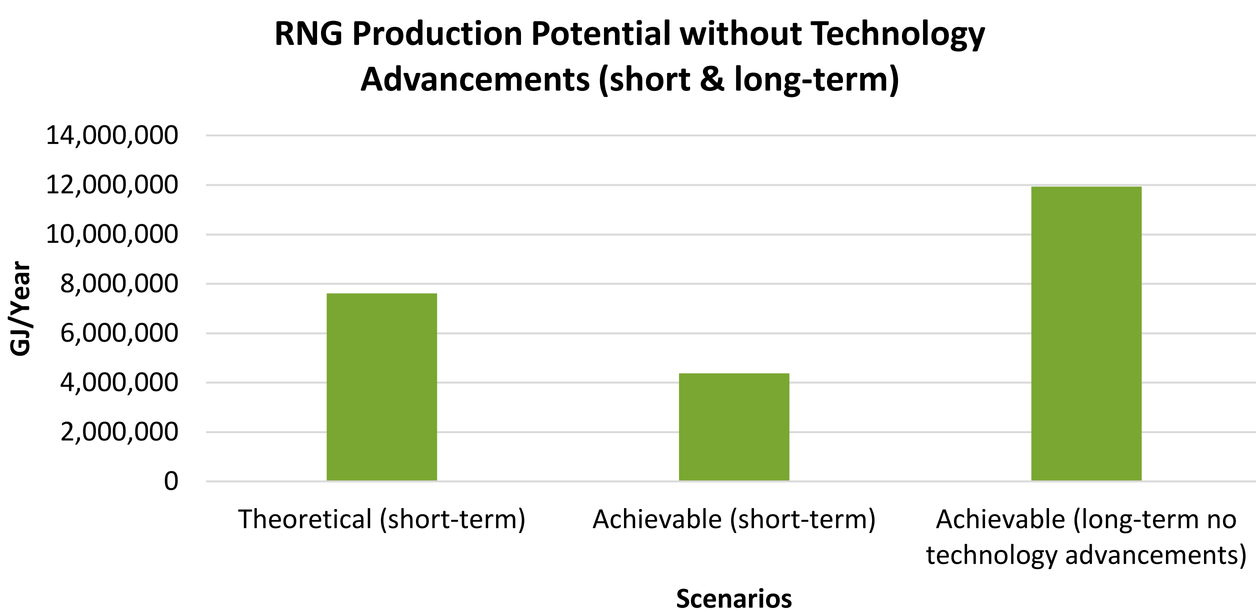
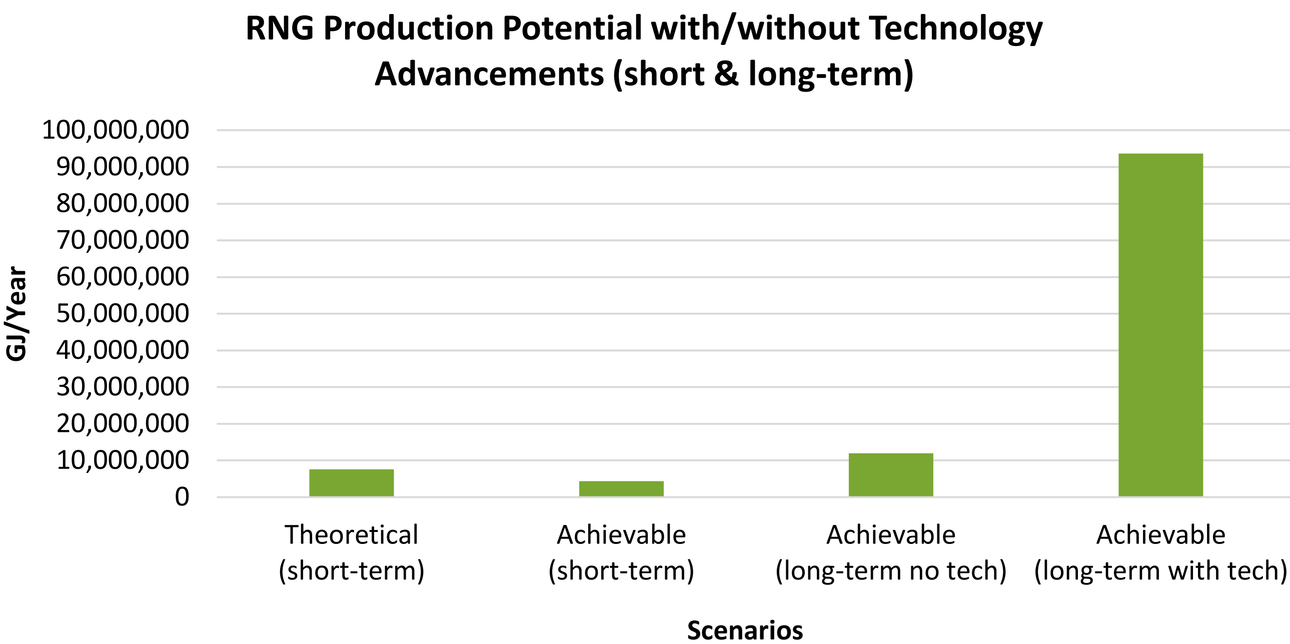


Figure 2: RNG Production Potential with/without Technology Advancements at $28/GJ



2. Introduction

Production of Renewable Natural Gas (RNG) can currently be achieved by two general methods. Biogas can be produced within anaerobic digestion (AD) plants, or it can occur within landfills and be collected using wells and pipes; biogas produced in landfills is known as landfill gas (LFG). Once captured, biogas or LFG can be upgraded to RNG. This process involves cleaning and refining the biogas or LFG to remove carbon dioxide and other contaminates so that it meets natural gas pipeline specifications.

Currently, a third method for producing biogas from wood biomass is also being developed. This thermochemical method uses technology to first convert wood feedstock into synthetic gas, before transforming the synthetic gas into RNG. In 2013, Göteborg Energi successfully opened the first large-scale thermochemical plant for producing RNG from wood feedstock in Gothenburg, Sweden. Gaz Métro recently announced success with a similar demonstration project in Boucherville, Québec.

The objective of this study was to determine theoretical and achievable RNG production potential within B.C. based on available agricultural, commercial, municipal, wastewater, and forestry waste feedstock (herein referred to as feedstocks), and LFG. Achievable RNG production potential was assessed under two different scenarios; a short-term scenario using currently available feedstocks and technologies, and a long-term scenario using projected increased feedstock availability in 2035 and assuming advancements in wood RNG technology.

3. RNG Feedstocks

Feedstocks used to produce RNG can be grouped into six broad categories. These six categories are:

- Agricultural: manure and bedding from livestock operations, and crop residues;
- Commercial: industrial, commercial, and institutional source-separated organics, and wood waste from demolition, land-clearing, and construction;
- Municipal: residential source-separated organics;
- Wastewater: sludge from wastewater treatment plants and pulp mills;
- Landfills: waste buried in landfills; and
- Forestry: by-products from industrial forest processes.

When assessing B.C.'s RNG production potential, feedstock data is required. Where this data was missing or wasn't detailed enough for this study, assumptions were made. Whenever these assumptions were made, every effort was taken to ensure they were as realistic as possible.

3.1 Agricultural Feedstock

Most agricultural AD plants will be designed for dairy or hog manure from a single farm, and possibly if available, some chicken layer manure and/or chicken broiler or turkey litter. Beef cattle AD plants will be designed for cattle manure from a single farm or several farms in close proximity. Agricultural AD plants, as defined by provincial regulations, are allowed to accept up to 49% Industrial, Commercial, and Institutional (ICI) source-separated organic (SSOs) feedstock. ICI SSO feedstock is hugely beneficial to agricultural AD plants because it has a much higher biogas production potential than manure and bedding.

The following is an assessment of the different types of agricultural feedstock in B.C. suitable for RNG production.[1] Where available, data for livestock populations was taken from Statistics Canada's 2011 Agricultural Census and industry publications. Feedstock estimates were taken from the B.C. Ministry of Agriculture's Agricultural Composting Handbook, and the Canada – British Columbia Environmental Farm Plan Program Reference Guide.

Dairy Manure

In B.C., > 90% of dairy cattle are currently raised in the regional districts of the Cowichan Valley, Comox Valley, Fraser Valley, Greater Vancouver, North Okanagan, and Columbia-Shuswap. Dairy manure produced in other regional districts wasn't considered in this study as the volume of feedstock is too small to have a noticeable impact on RNG production potential.

Estimated manure production per milking dairy cow and associated livestock is 38 m^3/year. Dairy manure has an average bulk density of 990 kg/m^3 and a 6% average dry matter content. Considered an excellent feedstock, when digested in a complete mix AD plant dairy manure is assumed to have an average methane (CH_4) production potential of 15 Nm^3/tonne.[2] It was assumed that due to dairy manure's low dry matter content, this feedstock will not be transported from farm to farm. As such, only dairy farms within close proximity to the natural gas pipeline were assumed able to produce RNG.

According to B.C. Agrifood Industry Year in Review reports from the B.C. Ministry of Agriculture, milk production by B.C. dairy farmers increased by ~1%/year since 2008. As such, it was assumed that the number of dairy cows in B.C. will continue to grow by 1%/year until 2035.

Pig Manure

In B.C., > 84% of pigs are currently raised in the Fraser Valley. Pig manure produced in other regional districts wasn't considered in this study as the volume of feedstock is too small to have a noticeable impact on RNG production potential.

Estimated manure production per pig (from grower to finisher) is 4 m^3/year. Pig manure has an average bulk density of 1,000 kg/m^3 and a 5% average dry matter content. Considered an excellent feedstock, when digested in a complete mix AD plant pig manure is assumed to have an average CH_4 production potential of 19 Nm^3/tonne.[3] It was assumed that due to pig manure's low dry matter content, this feedstock will not be transported from farm to farm. As such, only pig farms within close proximity to the natural gas pipeline were assumed able to produce RNG.

According to B.C. Agrifood Industry Year in Review reports from the B.C. Ministry of Agriculture, pork production by B.C. pig farmers increased by ~2%/year since 2012. As such, it was assumed that the number of pigs in B.C. will continue to grow by 2%/year until 2035.

Layer Manure

In B.C., > 90% of laying hens currently live in the regional districts of Cowichan Valley, Fraser Valley, Greater Vancouver, and Columbia-Shuswap. Layer manure produced in other regional districts wasn't considered in this study as the volume of feedstock is either too small to have a noticeable impact on RNG production

[1] Manure and bedding from geese, ducks, pheasants, sheep, emus, and other less-common livestock has not been included in this study as the population of these animals in B.C. is very small.

[2] Estimate using data from Swedish Waste Management, Swedish Gas Technology Center, and contact with Mats Edström (RISE).

[3] *Ibid.*

potential, or the geographical distribution of hens is too large to enable sufficient volumes of layer manure to be collected.

Estimated manure production for pullets (layers under 19 weeks of age) is 0.014m^3/year/bird, and for layers is 0.05m^3/year/bird. Layer manure has an average bulk density of 470 kg/m^3 and a 55% average dry matter content. Considered a suitable feedstock, layer manure's high nitrogen content can inhibit biogas production. As such, this feedstock shouldn't account for more than 20%[4] of an AD plant's total feedstock, and therefore layer manure will most likely be digested in dairy or hog manure AD plants. When digested in a complete mix AD plant layer manure is assumed to have an average CH_4 production potential of 69 Nm^3/tonne.[5] It was assumed that due to layer manure's high dry matter content, this feedstock could be transported to AD plants within the regional district in which it is produced.

According to B.C. Agrifood Industry Year in Review reports from the B.C. Ministry of Agriculture, egg production by B.C. layer farmers increased by ~2%/year since 2012. As such, it was assumed that the number of layers in B.C. will continue to grow by 2%/year until 2035.

Beef Cattle Manure

In B.C., > 80% of beef cattle are currently raised in the regional districts of Thompson-Nicola, Cariboo, Fraser-Fort George, Bulkley-Nechako, and Peace River. Cattle manure produced in other regional districts wasn't considered in this study as the volume of feedstock is either too small to have a noticeable impact on RNG production potential, or the geographical distribution of cattle is too large to enable sufficient volumes of this feedstock to be collected.

Estimated manure production per beef cow and associated livestock is 12 m^3/year. However, because cattle spend roughly half their time in fields, and because some cattle farms are far from the natural gas pipeline, only ¼ of the cattle manure produced was assumed potentially available for RNG production. Cattle manure has an average bulk density of 710 kg/m^3 and a 30% average dry matter content. Considered a suitable feedstock, cattle manure must be diluted with water/wet feedstocks for complete mix AD plants.

When digested in a complete mix AD plant cattle manure is assumed to have an average CH_4 production potential of 50 Nm^3/tonne.[6] It was assumed that water/wet feedstocks are available for diluting cattle manure, and that due to its moderate dry matter content, this feedstock could be transported to AD plants within the Census Consolidated Subdivision (CCS) in which it is produced.

According to B.C. Agrifood Industry Year in Review reports from the B.C. Ministry of Agriculture, beef production by B.C. cattle farmers decreased by ~5%/year between 2007 and 2012, before stabilising over the past few years. As such, it was assumed that the number of cattle in B.C. will stay the same until 2035.

Broiler & Turkey Litter

In B.C., > 98% of broiler hens are currently raised in the regional districts of Fraser Valley, Greater Vancouver, and North Okanagan, and > 93% of turkey are currently raised in the Fraser Valley and Greater Vancouver. Broiler and turkey litter produced in other regional districts wasn't considered in this study as the volume of feedstock is either too small to have a noticeable impact on RNG production potential, or the

[4] Edström et.al., 2013

[5] Estimate using data from Swedish Waste Management, Swedish Gas Technology Center and contact with Mats Edström (RISE).

[6] *Ibid.*

geographical distribution of birds is too large to enable sufficient volumes of broiler and turkey litter to be collected.

Estimated broiler and turkey litter production is 0.035 m^3/year/bird and 0.13 m^3/year/bird respectively. Broiler and turkey litter have average bulk densities of 330 kg/m^3 and 380 kg/m^3, and average dry matter contents of 75% and 70% respectively. Considered suitable feedstocks, broiler and turkey litter's high nitrogen contents can inhibit biogas production. Therefore these feedstock shouldn't account for more than 10%[7] of an AD plant's total feedstock, and as such all broiler and turkey litter will most likely be digested in dairy or hog manure AD plants.

When digested in a complete mix AD plant, broiler and turkey litter are assumed to have an average CH_4 production potential of 69 Nm^3/tonne.[8] Due to their high wood content (most farmers bed on wood shavings), broiler and turkey litter are also suitable for gasification or pyrolysis. When used for gasification or pyrolysis, broiler and turkey litter have a much higher estimated CH_4 production potential of 208 Nm^3/tonne.[9] It was assumed that due to broiler and turkey litter's high dry matter content, these feedstocks could be transported to AD plants within the regional district in which they are produced.

According to B.C. Agrifood Industry Year in Review reports from the B.C. Ministry of Agriculture, broiler production by B.C. broiler farmers has increased by ~1%/year since 2007, while turkey production has hardly changed. As such, it was assumed that the number of broilers and turkeys in B.C. will grow by 1%/year and 0.5%/year until 2035 respectively.

Horse Bedding

In B.C., while horses are currently present in every regional district, most regional districts have horse populations that are either too small to have a noticeable impact on RNG production potential, or the geographical distribution of horses is too large to enable sufficient volumes of horse bedding to be collected. Due to this, only bedding from the Capital Region, Fraser Valley, Greater Vancouver, Okanagan-Similkameen, Central, and North Okanagan was considered.

Estimated bedding production per horse is 21 m^3/year. Horse bedding has an average bulk density of 850 kg/m^3 and a 35% average dry matter content. Due to its high wood content (most equine facilities bed on wood shavings), horse bedding was assumed unsuitable for complete mix AD plants. Instead, horse bedding was assumed suitable for gasification or pyrolysis. When used for gasification or pyrolysis, horse bedding is assumed to have an average CH_4 production potential of 89 Nm^3/tonne[10]. It was assumed that due to horse bedding's moderate dry matter content, this feedstock could be transported to gasification or pyrolysis plants within the CCS in which it is produced.

According to Horse Council B.C.'s Equine Industry Study, horse numbers in B.C. have remained fairly stable for the past ten years, while expectation is that this number will remain fairly consistent as the industry stabilises. As such, it was assumed that the number of horses in B.C. will stay the same until 2035.

[7] Edström et. al., 2013.
[8] Estimate using data from Swedish Waste Management, Swedish Gas Technology Center and contact with Mats Edström (RISE).
[9] Värmeforsk, 2012.
[10] *Ibid.*

Crop Residue
Crop residues are the small amount of vegetative material left on fields after harvest; farmers generally take as much from the field during harvest as possible, leaving as little as possible. After harvest, and to reduce soil erosion, crop residues are often incorporated into the soil or they are left on the soil over winter before incorporation the following spring. Spoiled harvest are any crops that have deteriorated to the point in which they are no longer edible.

For the purposes of this study, crop residues and spoiled harvests were not included as feedstocks for RNG production. The reasons for this are threefold. First, crop residues often have a high fiber content, meaning they take a long time to breakdown inside AD plants and are therefore not a favoured feedstock. Second, crop residues and spoiled harvests have seasonal variation (i.e., they are usually available only once or at certain times of the year), making it difficult to incorporate these into AD plants that prefer year-round feedstock supply contracts without needing expensive storage. Third, the volume of agricultural residues in B.C. compared to other feedstocks (such as manure, food processing waste, etc.) is very small, and as such it is unlikely these residues will have any noticeable impact on RNG production potential.

Energy Crops
Growing dedicated plant biomass, so called “energy crops”, for biogas production is not new. In Germany and Austria for example, the number of AD plants using energy crops is estimated to be in the thousands. Despite widespread use, energy crops were not considered in this study as a feedstock for RNG production. The reason for this is that this study is solely focused on using waste feedstocks to produce RNG.

Table 1: Summary of Manure and Bedding Feedstocks

Feedstock	Bulk Density	Dry Matter	CH_4 Potential (per tonne)	Location	Volume (per animal)	Cost	Availability
Dairy Manure	990kg/m^3	6%	15 m^3	CWV, CV, FV, GV, NO, CS	38 m^3/year	None	On-farm only
Pig Manure	1,000/m^3	5%	19 m^3	FV	4 m^3/year	None	On-farm only
Layer Manure	470/m^3	55%	69 m^3	CWV, FV, GR, CS	.014 and .05 m^3/year	$10/tonne	Within RD
Beef Cattle Manure	710/m^3	30%	50 m^3	TN, C, FG, BN, PR	12 m^3/year	None	Within CCS
Broiler Litter	330/m^3	75%	69 or 208 m^3	FV, GV, NO	.035 m^3/year	$10/tonne	Within RD
Turkey Litter	380/m^3	70%	69 or 208 m^3	FV, GV	.013 m^3/year	$10/tonne	Within RD
Horse Bedding	850/m^3	35%	89 m^3	CR, FV, GV, OS, CO, NO	21 m^3/year	None	Within CCS

Key: Bulkley-Nechako (BN), Capital Region (CR), Cariboo (C), Central Okanagan (CO), Columbia-Shuswap (CS), Comox Valley (CV), Cowichan Valley (CWV), Fraser-Fort George (FG), Fraser Valley (FV), Greater Vancouver (GV), North Okanagan (NO), Okanagan-Similkameen (OS), Peace River (PR) and Thompson-Nicola (TN).

Summary of Assumptions for Agriculture
When assessing the RNG production potential of agricultural feedstocks in B.C. some assumptions were made. These assumptions included the following:

- Dairy and pig manure will not be transported between farms;
- Only dairy and pig farms close to the natural gas pipeline (< 1km) will build AD plants;
- Cattle farms will have sufficient water/wet feedstock required for dilution of their manure;

- Cattle manure and horse bedding can be transported within the Census Consolidated Subdivision (CCS) in which they are produced;
- Layer manure, broiler, and turkey litter can be transported within the regional district in which they are produced;
- Layer manure, broiler and turkey litter will only be digested to a maximum of 20% and 10% respectively in dairy or hog manure AD plants; and
- Agricultural AD plants will accept up to 49% ICI SSO (if available).

3.2 Commercial Feedstock

Commercial source separated organics (SSOs) is organic waste produced from industrial, commercial, and institutional (ICI) activities, such as food processing, restaurants, and accommodation. Due to large variations in ICI activities, estimating available volumes and composition of this feedstock was very challenging.

Firstly, the cost and effort required by ICI facilities to separate organic waste from other waste streams will vary. Some facilities, such as supermarkets and food processors, who produce large volumes of organic waste and have staff responsible for disposal, will likely separate organic waste more easily and successfully than facilities that produce small volumes, or who rely on others to separate their waste streams (such as office buildings). Secondly, securing ICI SSOs for RNG production can be challenging, as this feedstock may already be processed on-site, sold, or given away for other purposes, such as animal feed.

While AD plants can be built specifically to process ICI SSOs, there are very few such plants in Canada. As such, it was assumed this feedstock will be delivered to agricultural or municipal AD plants. This assumption is important as ICI SSOs can be classed as ‘pre-consumer’ (coming from manufactures, wholesale and retail trade, etc.) or ‘post-consumer’ (originating from accommodation, food services, offices, etc.). In B.C., and based on current provincial regulations, only pre-consumer SSOs is allowed into agricultural AD plants.

Demolition, land-clearing, and construction (DLC) waste consists largely of inert solid waste resulting from construction, remodelling, and demolition projects. Examples of DLC waste include wood, soft construction materials such as plastic, carpet, and insulation, and land clearing waste. Highly unsuitable for AD plants, DLC wood waste is a suitable feedstock for gasification or pyrolysis.

According to Metro Vancouver’s 2013 Recycling and Solid Waste Management Report, per capita disposal rate for the region was 0.55 tonnes/year. Of this, ICI and DLC waste accounted for 0.17 and 0.16 tonnes respectively. Similar per capita disposal rate estimations are also provided by the B.C. Government, who in their 1990 – 2014 Municipal Solid Waste Disposal Report estimated that in 2014 each British Columbian disposed of 0.52 tonnes of solid waste.

Disposal rates do not include waste that is reused or recycled. According to Metro Vancouver’s 2013 Recycling and Solid Waste Management Report, per capita ICI and DLC recycling rates were 0.11 and 0.5 tonnes/year respectively. Based on this information, it was assumed per capita ICI and DLC waste production rates (both disposed and recycled) in B.C. are 0.28 and 0.66 tonnes/year respectively. Metro Vancouver’s 2013 Recycling & Solid Waste Management Report shows per capita waste production rates remained fairly stable from 1994 – 2013. As such, it was assumed that per capita disposal rates will remain stable until 2035.

Metro Vancouver's 2014 ICI Waste Characterization Program found that 35% of ICI waste being landfilled is compostable organics. A 2011 Solid Waste Stream Composition Study by the Capital Regional District found landfilled ICI SSOs consisted of 32% compostable organics. However, these studies only captured the percentage of compostable organics in ICI waste being landfilled. It is highly likely that the percentage of compostable organics in ICI waste not being landfilled but composted or used for other purposes is much higher. As such it was assumed 50% of ICI waste in B.C. is compostable organics suitable for AD plants.

The Capital Regional District's study found that 63% of DLC waste consisted of wood or wood products (the remaining 36% being construction and demolition material). Metro Vancouver's 2011 Demolition, Land-clearing, and Construction Waste Composition Monitoring Report found that 54% of DLC waste consisted of wood. As with ICI waste, these studies only captured the percentage being landfilled. It is highly likely that the percentage of wood in DLC waste not being landfilled but used for other purposes is higher. As such it was assumed 60% of DLC waste is suitable for gasification or pyrolysis.

No study could be found showing the percentage of ICI waste from pre-consumer and post-consumer sources. Metro Vancouver's 2014 ICI Waste Characterization Study found accommodation/food and business services (post-consumer) accounted for 9% and 7% of ICI waste respectively, while manufacturing and retail (pre-consumer) accounted for 10% and 4% respectively. The City of Calgary's Industrial Commercial Institutional Waste Diversion Progress Update found accommodation/food and business commercial services (post-consumer) accounted for 17% and 16% of ICI waste respectively, while retail and wholesale trade, manufacturing and warehousing (pre-consumer) accounted for 15%, 4%, and 6% respectively.

As with the percentage of compostable organics in ICI waste, these studies only captured the percentage of pre and post-consumer waste being landfilled. Due to the likely lower cost and effort required by pre-consumer ICI facilities to separate their organic waste from other waste streams, it is highly likely that the percentage of pre-consumer waste being produced is higher than that being landfilled. As such, it was assumed that 50% of ICI SSOs is pre-consumer and therefore suitable for agricultural AD plants.

The CH_4 production potential of ICI SSOs can vary greatly, from as little as 67 Nm^3/tonne to as much as 383 Nm^3/tonne. Despite this, when digested in a complete mix AD plant ICI SSOs was assumed to have a CH_4 production potential of 140 m^3/tonne.[11] It was assumed that ICI SSOs can be transported to AD plants within the regional district in which it is produced. When used for gasification or pyrolysis, DLC waste has an assumed average CH_4 production potential of 198 Nm^3/tonne.[12] It was assumed that DLC wood waste can also be transported to gasification or pyrolysis plants within the regional district in which it is produced.

Summary of Assumptions

When assessing the RNG production potential of ICI SSO and DLC waste in B.C. some assumptions were made. These assumptions include the following:

- ICI SSOs is delivered to either agricultural or municipal AD plants;
- ICI SSOs per capita production rate is 0.28 tonnes/year;
- DLC waste per capital production rate is 0.66 tonnes/year;

[11] Estimate using data from Swedish Waste Management, Swedish Gas Technology Center and contact with Mats Edström (RISE).
[12] Värmeforsk, 2012.

- 50% of ICI waste is organic waste suitable for AD plants, and 50% of this is pre-consumer waste suitable for agricultural AD plants;
- 60% of DLC waste is wood waste suitable for gasification or pyrolysis plants;
- DLC wood waste has an average moisture content of 23%;
- ICI SSOs and DLC wood waste can be transported within the regional district they are produced;
- ICI SSOs has an average CH_4 production potential of 140 Nm^3/tonne;
- DLC wood waste has an average CH_4 production potential of 198 Nm^3/tonne; and
- ICI SSOs and DLC waste per capita production rates will be 0.28 tonnes/year and 0.66 tonnes/year in 2035 respectively.

3.3 Municipal Feedstock

Residential Source Separated Organics (SSOs) refers to organic waste that has been separated from the residential garbage stream. Within Canada there are examples of residential SSOs being co-digested at wastewater treatment plants. Despite this, residential SSOs is most often digested at municipal AD plants, either alone, or with ICI SSOs, and/or wastewater treatment plant sludge. As such, it was assumed this feedstock will only be digested in municipal AD plants.

Residential SSOs is suitable for wet or dry AD plants.[13] Wet (liquid) AD plants require feedstock with <15% average dry matter content. For feedstock with higher dry matter content, such as residential SSOs, water or other wet feedstocks can be added. While wet AD plants generally have larger footprints and higher feedstock and digestate treatment costs than dry AD plants, they generally produce 3 – 4 times more biogas per tonne of feedstock. Because the aim is to produce as much RNG as possible, it was assumed all residential SSOs will be digested in wet AD plants.

According to Metro Vancouver’s 2013 Recycling and Solid Waste Management Report, per capita disposal rate for the region was 0.55 tonnes/year. Of this, residential waste accounted for 0.21 tonnes. Disposal rates do not include waste that is reused or recycled. According to Metro Vancouver’s 2013 Recycling and Solid Waste Management Report, per capita residential recycling rates were 0.22 tonnes/year. Based on this information, it was assumed the per capita residential waste production rate (both disposed and recycled) in B.C. is 0.44 tonnes/year. Metro Vancouver’s 2013 Recycling and Solid Waste Management Report shows that per capita waste production rates have remained fairly stable from 1994 to 2013. As such it was assumed that this per capita disposal rate will remain consistent until 2035.

Environment Canada’s 2013 Technical Document on Municipal Solid Waste Organics Processing shows that biodegradable material, typically food waste and leaf and yard waste, constitutes approximately 40% of the residential waste stream. A 2011 Capital Regional District Solid Waste Stream Composition Study shows that on average 35% of residential waste is organic, while Metro Vancouver’s 2015 Waste Composition monitoring program found that compostable organics accounted for 35% of the waste from single and multifamily residential.

Determining how much of the organic waste in residential SSOs has good biogas potential (i.e., food waste), and how much has poor biogas potential (i.e., yard waste) is difficult. Most waste composition studies do not provide the required level of detail, while those that do only capture the organic waste being thrown away (i.e., they do not capture the organic waste being recycled through commercial and

[13] While the AD plants in B.C. digesting residential SSOs are dry, most residential SSOs AD plants in Canada and globally are wet.

household composting).[14] Based on the information available, it was assumed that 40% of residential waste is organic, and that 75% of this organic waste will produce biogas in AD plants (the remaining 25% being yard waste).

Residential SSOs is produced where people live. As such, residential SSOs will be produced in cities, towns, municipalities, and small rural communities. While the majority of residential organic waste in B.C. is currently collected and transported to landfills or compost facilities, collection becomes difficult in sparsely populated areas. Therefore it was assumed that residential SSOs is only collected for AD plants in areas of B.C. where the population density is > 20/km^2.

The CH_4 production potential of residential SSOs can vary greatly, from as little as 78 Nm^3/tonne to as much as 129 Nm^3/tonne. Despite this, when digested in a complete mix AD plant, residential SSOs was assumed to have an average CH_4 production potential of 100 Nm^3/tonne.[15] It was assumed that residential SSOs can be transported to AD plants within the regional district in which it is produced.

Summary of Assumptions

When assessing the RNG production potential of residential SSOs in B.C. some assumptions were made. These assumptions include the following:

- All residential SSOs is delivered to municipal AD plants;
- Residential SSOs per capita production rate is 0.44 tonnes/year;
- 30% of residential waste is suitable for AD plants;
- Only residential SSOs produced in areas with a population density of >20 people/km^2 is available for RNG production;
- Residential SSOs can be transported to plants within the regional district in which it is produced;
- CH_4 production potential is 100 Nm^3/tonne; and
- Per capita production rates will be 0.44 tonnes/year in 2035.

3.4 Wastewater Feedstock

At Wastewater Treatment Plants (WWTPs) wastewater flushed down the toilet or washed down the drain is treated using primary or secondary treatment. Primary treatment generally involves screens and/or settling tanks. Secondary treatment generally involves aerobic biological processes. Sludge from WWTPs is a suitable feedstock for AD plants. The production of pulp is associated with the generation of large quantities of wastewater. Treatment of pulp mill wastewater using activated sludge systems can result in production of Waste Activated Sludge (WAS). WAS is a suitable feedstock for AD plants.

All B.C. WWTPs require authorization permits. These permits show a WWTP's maximum daily discharge rate and daily biochemical oxygen demand (BOD) concentration levels, and sometimes annual average daily discharge rates. Some WWTPs also publish actual daily discharge rates. Based on this information it is estimated that thirteen WWTPs account for > 90% of wastewater treated in B.C. (Table 2).

Of the thirteen WWTPs, nine currently produce biogas through AD that is either combusted to produce heat and/or electricity (as at five WWTPs), or it is flared (as at four WWTPS). The remaining WWTPs don't

[14] According to Stats Canada, in 2011 over half of Canadian households (61%) participated in some form of composting (www.statcan.gc.ca/pub/16-002-x/2013001/article/11848-eng.htm).
[15] Estimate using data from Swedish Waste Management, Swedish Gas Technology Center and contact with Mats Edström (RISE).

produce biogas. Due to the technology and infrastructure investments required to produce heat and/or electricity from biogas, it was assumed that only WWTPs currently flaring biogas are able to produce RNG in the short-term. It was also assumed that Langley and Duncan WWTPs send their sludge to nearby municipal AD plants, while Clover Point and Macaulay WWTPs do not produce sludge suitable for RNG production.

For 2035, it was assumed that sludge production will increase with projected population growth, and that all WWTPs that currently produce biogas will be able to produce RNG. It was also assumed that by 2035 a WWTP built on Vancouver Island will produce RNG. When digested in a complete mix AD plant, WWTP sludge was assumed to have an average CH_4 production potential of 502 Nm^3/tonne BOD.[16]

Table 2: Largest WWTPs in B.C.

Name	Muni	Discharge (m^3/day)			Maximum Daily BOD (mg/l)	Current Operation
		Maximum	Actually	Average		
Iona Island	Richmond	1,530,000	600,000	N/A	130	Biogas for heat/electricity
Annacis Island	Delta	1,050,000	500,000	N/A	45	Biogas for heat/ electricity
Lion's Gate	North Vancouver	318,000	90,000	N/A	130	Biogas for heat and engines
Lulu Island	Richmond	233,000	80,000	N/A	45	Biogas for heat
Clover Point	Nanaimo	185,000	N/A	82,000	45	No biogas produced
Macaulay	Nanaimo	150,000	N/A	50,000	45	No biogas produced
GNPCC	Nanaimo	80,870	N/A	40,950	130	Biogas for heat/ electricity
J.A.M.E.S	Abbotsford	70,000	N/A	48,000	45	Biogas flared
Kamloops	Kamloops	55,000	40,000	N/A	30	Biogas flared
Duncan	Nanaimo	49,000	N/A	N/A	30	No biogas produced
Chilliwack	Chilliwack	45,000	N/A	N/A	45	Biogas flared
Landsdowne Road	Prince George	45,000	N/A	N/A	30	Biogas flared
Langley	Langley	42,000	12,500	N/A	45	No biogas produced

Within B.C., 17 pulp mills are close to the natural gas pipeline (Table 3).[17] Of these mills, eight were assumed to have activated sludge systems that produce WAS.[18] Because information regarding WAS production volumes at pulp mills couldn't be found, it was assumed that these eight pulp mills produce an average of 1,500 kg WAS with 1.5% average dry matter content for every one tonne of pulp.[19] It was also assumed that the capacity utilization of these eight pulp mills is 100%.[20] When digested in a complete mix AD plant WAS was assumed to have an average CH_4 production potential of 1.8 Nm^3/tonne.[21]

[16] Swedish Institute of Agricultural and Environmental Engineering (JTI), 1988.
[17] Neucel Specialty Cellulose in Port Alice is the only pulp mill considered too far from the natural gas pipeline.
[18] The other pulp mills were assumed to use aerated stabilization basins which do not produce feedstock suitable for AD plants.
[19] Elliott A, Mahmood T (2005) Survey Benchmarks Generation, Management of Solid Residues. Pulp Pap 79(12):49–55.
[20] A 2011 B.C. Ministry of Forests, Lands and Natural Resource Operations report titled Major Primary Timber Processing Facilities in B.C. found that capacity utilization of pulp mills in B.C was only slightly below 100%.
[21] JTI, 1988.

According to a 2011 study by the B.C. Ministry of Forestry, Lands and Natural Resource Operations, total output by B.C. pulp mills saw a 15% decline from 1991 to 2011.[22] Despite this, and due to the difficulties in forecasting the future of B.C.'s pulp mills, it was assumed that pulp mill output in B.C., and therefore WAS production, will remain stable to 2035.

Table 3: B.C. Pulp Mills Close to the Natural Gas Pipeline

Name	Municipality	Capacity (t/year)	WAS Production (t/year)
Canfor	Prince George	313,000	N/A
	Prince George	140,000	N/A
	Prince George*	568,000	852,000
	Taylor	210,000	N/A
Cariboo Pulp and Paper	Quesnel	331,000	N/A
Catalyst Paper	Crofton*	373,000	559,500
	Port Alberni	186,000	N/A
	Power River*	354,000	531,000
Celgas Pulp Co	Castlegar	503,000	N/A
Chetwynd Mechanical Pulp	Chetwynd*	205,000	307,500
Domtar Pulp	Kamloops*	460,000	690,000
Howe Sound Pulp & Paper	Port Mellon*	725,000	1,087,500
MacKenzie Pulp Mill Corp	Mackenzie	224,000	N/A
Nanaimo Forest Products	Nanaimo*	327,000	490,500
Paper Excellence	Skookumchuck	248,000	N/A
	New Westminster	31,000	N/A
Quesnel River Pulp	Quesnel*	370,000	555,000

*Note: * Pulp mills thought to produce WAS.*

Summary of Assumptions

When assessing the RNG production potential of feedstocks from WWTPs and pulp mills in B.C. some assumptions were made. These assumptions included the following:

- Only WWTPs currently producing biogas that isn't combusted for heat and/or electricity have the potential to produce RNG in the short-term;
- Langley and Duncan WWTPs will send their sludge to nearby municipal AD plants while Clover Point and Macaulay WWTPs produce no useable sludge;
- CH_4 production potential of WWTP sludge is 502 Nm^3/tonne BOD;
- WWTP sludge production will increase in line with estimated population growth to 2035;
- A WWTP will be built on Vancouver Island capable of producing RNG by 2035;
- Pulp mills with activated sludge systems produce 1,500 kg WAS with a dry matter content of 1.5% for every tonne of pulp produced;
- The capacity utilization of B.C.'s pulp mills is 100% and the size/number of pulp mills in 2035 will be the same as today; and
- CH_4 production potential of WAS is 1.8 Nm^3/tonne.

[22] Major Primary Timber Processing Facilities in British Columbia 2011 www.for.gov.bc.ca/ftp/het/external/!publish/web/mill%20list/Mill%20List%20Public%20Report%202011.pdf

3.5 Landfill Gas

Landfill gas (LFG) is a by-product from the decomposition of organic waste buried in landfills. LFG is captured through a system of vertical or horizontal perforated pipes drilled into the landfill at regular intervals. A vacuum in the pipes, created using blowers or compressors, is used to draw LFG into the pipe where it is sent to a central location for flaring or use.

B.C.'s Landfill Gas Management Regulation[23] establishes province-wide criteria for LFG capture from municipal landfills. Under this Regulation any landfill estimated to generate > 1,000 tonnes CH_4/year is required to install a LFG capture system. While the efficiency of a LFG capture system depends upon various factors, including pipe placement, waste permeability, and landfill operations, B.C.'s regulation sets a capture rate performance objective of 75%.

Due to the Landfill Gas Management Regulation, it was assumed only landfills that generate > 1,000 tonnes CH_4/year will install LFG capture systems. It was also assumed that these landfills are within close proximity to the Fortis or PNG natural gas pipeline. Smaller landfills, with the exception of those already capturing LFG, are assumed not to install LFG capture systems as cost to do so is prohibitive. It was also assumed that all LFG capture systems in B.C. achieve a 75% capture rate.

Currently, the availability of information regarding LFG production in B.C. is extremely limited. In 2008 the B.C. Ministry of Environment undertook an inventory of GHG generation from landfills in B.C.[24] This inventory, commissioned as a first-step estimating report to provide an overall high-level perspective on CH_4 generation from B.C. landfills, estimated CH_4 generation from 2005 – 2030 for all municipal landfills with a disposal rate > 10,000 tonnes/year; therefore accounting for ~90% of total municipal solid waste disposed of at provincially regulated landfills in B.C.

Since completion of this inventory, several B.C. landfills have submitted LFG Assessment Reports. Some of these Assessment Reports show similar CH_4 generation estimates to those in the Ministry's 2008 inventory, others are less similar.[25] Where the Ministry of Environment's CH_4 estimates are similar to those provided in the landfill's Assessment Reports, these estimates have been used to calculate the landfill's CH_4 potential for 2035. Where the Ministry's CH_4 generation estimates differ significantly from those provided in the landfill's Assessment Reports, these estimates have been recalibrated using the landfill's own assessment report to calculate CH_4 potential for 2035 (Table 4).

The Ministry of Environment's inventory was completed in 2008. Since 2008 and over the coming years B.C. municipalities have or will introduce organic waste diversion programs. Since it is the decomposition of organic waste that produces LFG, these diversion programs will ultimately decrease LFG production. Despite this, organic waste takes a long time to decompose in landfills. As such, it was assumed that organic waste diversion programs will have minimal impact on LFG generation over the next twenty years.

Currently, three of the landfills estimated to generate > 1,000 tonnes CH_4/year (Hartland, Cache Creek, and Nanaimo) combust LFG to produce heat and electricity, while at a fourth (Vancouver) roughly ½ of the LFG is currently combusted to produce heat and electricity. Due to the technology and infrastructure investments to produce heat and electricity from combusted LFG, it was assumed that only LFG currently being flared will be used to produce RNG in the short-term.

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[23] www.env.gov.bc.ca/epd/codes/landfill_gas/

[24] www.env.gov.bc.ca/epd/codes/landfill_gas/pdf/inventory_ggg_landfills.pdf

[25] One reason for this could be that the LFG Assessment Reports were completed using a different LFG generation model.

Table 4: Estimated CH_4 Production & Capture from B.C.'s Largest Landfills

Regional District	Landfill	2016		2035	
		CH_4 Product (t/yr)	CH_4 Capture (t/yr)	CH_4 Product (t/yr)	CH_4 Capture (t/yr)
Alberni-Clayoquot	Alberni Valley	1,077	808	920	690
Capital Region	Hartland	N/A	N/A	12,366	9,252
Central Okanagan	Glenmore	4,411	3,308	8,017	6,013
Columbia Shuswap	Salmon Arm	730	548	1,024	768
Comox-Strathcona	Comox Valley	2,718	2,039	2,852	2,139
	Campbell River	1,029	772	N/A	N/A
East Kootenay	Central Cranbrook	N/A	N/A	1,401	1,051
Fraser-Fort George	Foothills	4,323	3,242	5,223	3,918
Fraser Valley	Bailey	3,447	2,585	4,919	3,689
	Minnie's Pit	2,323	1,742	3,412	2,559
Greater Vancouver	Vancouver	15,151	11,363	34,618	25,964
	Cache Creek	N/A	N/A	6,573	4,930
	Ecowaste	4,255	3,191	3,672	2,754
Nanaimo	Nanaimo	N/A	N/A	1,260	945
North Okanagan	Vernon	1,967	1,475	3,878	2,909
Okanagan-Similkameen	Campbell Mtn	1,513	1,135	2,397	1,797
Peace River	Ft. St. John	2,143	1,607	975	732
	Bessborough	N/A	N/A	1,728	1,296
Sunshine Coast	Sechelt	1,190	893	1,686	1,264
Thompson-Nicola	Mission Flats	1,639	1,229	2,591	1,943

Summary of Assumptions

When assessing the RNG production potential of LFG in B.C. some assumptions were made. These assumptions include the following:

- Only landfills estimated to produce > 1,000 tonnes CH_4/year will capture LFG;
- For landfills estimated to generate < 1,000 tonnes CH_4/year, the cost to install LFG capture systems is prohibitive;
- LFG capture systems have a capture efficiency of 75%;
- LFG production will not be significantly impacted by waste diversion programs by 2035;
- Only LFG not combusted for heat and electricity will be used to produce RNG in the short-term; and
- All landfills estimated to generate > 1,000 tonnes CH_4/year are within close proximity to the Fortis or PNG natural gas pipeline.

3.6 Forestry Feedstock

Forest feedstock is defined as by-product from industrial forest processes and can be composed of all parts of the tree, including the trunk, bark, branches, or roots. While this by-product can and often is used by other industries, such as for pulp and paper production, pellets, particle board, and by the agriculture sector, when there is excess supply this feedstock is often considered a waste product and therefore could be used for RNG production.

As with some agricultural feedstocks, such as horse bedding, forestry feedstock isn't suitable for AD plants. The reason for this is that forestry feedstock is rich in fibre, and fibre is very difficult to breakdown to produce biogas. As such, very little biogas can be produced from forestry feedstock. Instead, forestry feedstock must be thermally processed in gasification or pyrolysis plants. Once thermally processed, the syngas from these plants can be converted to RNG using some type of methanization technology.

In 2015, B.C. Hydro undertook an assessment of available wood biomass in the province.[26] As part of this study, the availability of biomass considered 'surplus' to the demands of B.C.'s forest industry, and therefore potentially available for energy generation, was estimated. In total, four sources of forestry biomass were identified. These were sawmill wood waste (including residual wood chips, sawdust, shavings, and bark), roadside logging residues (including tree tops, branches, and other non-saw log material derived during logging operations), pulp logs (the by-product created from the harvest of saw logs not suitable for lumber), and standing timber (non-harvested trees).

The objective of this study was to consider potential RNG production using waste feedstocks. As such, only by-products from the forestry sector were considered. Based on this, and assuming pulp logs surplus to the requirement of the pulp and paper industry have no other use, sawmill wood waste, roadside logging residues, and pulp logs were considered.[27] Furthermore, and due to the lack of commercial methanization technology, only forestry feedstock available in 2035 was considered. According to B.C. Hydro's study, by 2035 stable mid-term forestry harvest is forecast to occur (i.e., after supply of dead pine from the Mountain Pine Beetle epidemic is expected to be largely extinguished).

Table 5 shows B.C Hydro's estimates for the availability of sawmill waste, roadside logging residue, and pulp logs in Oven Dry Tonnes (ODT) for several regions of the province. Kamloops/Okanagan, Prince George, North-East, and North-West B.C. aren't included in the table as according to B.C Hydro's study, these areas aren't estimated to have available surplus forestry feedstock in 2035.

Table 5: Estimated Forestry Feedstock Availability (B.C. Hydro estimates)

Delivery Location	Estimated Availability (ODT/year)			
	Sawmill Waste	Roadside Residue	Pulp Log	Total
Parksville or Aldergrove	26,640	376,560	-	403,200
Canal Flats	-	69,840	-	69,840
Castlegar	158,400	134,640	-	293,040
Hanceville	-	12,240	-	12,240
Mackenzie	-	20,880	-	20,880
Chetwynd	6,480	117,360	71,280	195,120
Houston	6,480	720	143,280	150,480
Kitimat	15,120	12,240	46,800	74,160

B.C. Hydro's study of wood biomass is seen by some as being overly conservative in its estimates, particularly with regard to roadside logging residues. One reason for this could be that B.C. Hydro's study only forecasts the biomass that might be available for new electricity generation projects and that is

[26] www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wood-based-biomass-report-201507-industrial-forestry-service.pdf
[27] Harvesting standing timber to produce RNG would also raise questions related to carbon dioxide. Does it make sense to harvest trees, thereby returning sequestered carbon dioxide to the atmosphere, to produce low carbon fuel?

surplus to requirements. Because of this, work was undertaken by Brian Titus, Research Scientist at the Pacific Forestry Centre of Natural Resources Canada (NRCan), to estimate total maximum theoretical roadside logging residue that could be available based on estimated wood harvested in 2035 within different radii from natural gas compressor stations throughout B.C.

Based on the B.C. Hydro report and work carried out by NRCan, Table 6 was created to show estimated available sawmill waste and pulp logs for Timber Supply Areas (TSAs) using data from B.C. Hydro's report for sawmill waste and pulp logs, and estimated maximum theoretical roadside logging residues from NRCan for each TSA within 50km and 75km radii of natural gas compression stations.

Table 6: Estimated Forestry Feedstock Availability (NRCan estimates)

Timber Supply Area	Estimated Availability (ODT/year)					
	Sawmill Waste*	**Roadside Residue (50km radius)**	**Roadside Residue (75km radius)**	**Pulp Log***	**Total (50km radius)**	**Total (75km radius)**
Arrowsmith	-	-	1,325	-	-	1,325
Bulkley	6,480	22,013	24,592	143,280	171,773	174,352
Cascadia	-	3,020	3,368	-	3,020	3,368
Cranbrook	-	61,169	65,466	-	61,169	65,466
Dawson Creek	6,480	138,254	175,012	71,280	216,014	252,772
Fraser	26,640	116,517	109,524	-	143,157	136,164
Fort Nelson	-	523,273	732,517	-	523,273	732,517
Fort St. John	-	598,303	643,510	-	598,303	643,510
Invermere	-	-	3,433	-	-	3,433
Kalum	15,120	18,247	24,608	46,800	80,167	86,528
Kamloops	-	81,269	113,384	-	81,269	113,384
Kispiox	-	2,262	12,395	-	2,262	12,395
Kootenay Lake	158,400	8,343	12,005	-	166,743	170,405
Lakes	-	22,281	26,972	-	22,281	26,972
Lillooet	-	1,385	7,373	-	1,385	7,373
MacKenzie	-	86,312	131,491	-	86,312	131,491
Merritt	-	59,307	69,263	-	59,307	69,263
100 Mile House	-	55,290	58,787	-	55,290	58,787
Morice	-	43,374	84,304	-	43,374	84,304
North Coast	-	-	1,211	-	-	1,211
Okanagan	-	-	13,217	-	-	13,217
Pacific	-	-	3,932	-	-	3,932
Prince George	-	1,217,178	1,517,113	-	1,217,178	1,517,113
Quesnel	-	85,594	105,192	-	85,594	105,192
Soo	-	3,184	8,110	-	3,184	8,110
Sunshine Coast	-	2,556	10,927	-	2,556	10,927
Williams Lake	-	68,597	108,063	-	68,597	108,063
Totals	**213,120**	**3,217,728**	**4,067,094**	**261,360**	**3,692,208**	**4,541,574**

*Note: * Estimated availability and delivery cost taken from B.C. Hydro report.*

Summary of Assumptions

When assessing the RNG production potential of forestry feedstock in B.C. some assumptions were made. These assumptions include the following:

- All biomass considered surplus to the demands of the B.C. forest industry in the B.C. Hydro report or estimated by NRCan can be used for RNG production in 2035;
- Standing timber is not considered a suitable feedstock as harvesting these trees will release sequestered carbon dioxide into the atmosphere; and
- All potential delivery locations identified in the B.C. Hydro report can connect to the FortisBC or PNG natural gas pipeline.

4. Short-Term RNG Production Potential

The above information regarding volume, availability, and CH_4 production potential of feedstock in B.C. was used to estimate RNG production potential assuming a market price of $28/GJ for the short-term; defined as the next few years in which little is expected to change regarding RNG feedstock availability or technology.

Theoretical short-term RNG production potential was estimated to be 7.6 PJ/year. However, theoretical production potential is the maximum amount of RNG that could be produced using the most favourable assumptions. Theoretical RNG production potential doesn't take into account certain realities, including:

- Plant operating capacity: AD plants are biological systems. If the biology within these systems is disrupted or upset, biogas production falls.[28] While every effort is made to ensure this doesn't happen, in reality few AD plants run at full capacity. It is therefore more realistic to assume an average operating capacity of 80%; and
- Feedstock availability: separating ICI organic waste from other waste streams can be difficult and costly, while some ICI feedstocks may have alternate uses (such as for rendering and animal feed). Collection and separation of residential organic waste requires implementation of 'green bin' collection programs that often only secure ~60% of total organic waste. It is therefore more realistic to assume only 80% of ICI and 60% of residential SSOs are available for RNG production.

Achievable short-term RNG production potential assuming a market price of $28/GJ was estimated to be 4.4 PJ/year. However, achievable RNG production potential doesn't include potential 'human factor'. For example, if a farmer is uninterested in activities beyond farming, or if a municipal manager feels more comfortable with composting organic waste than digesting it, it is unlikely RNG will be produced using the agricultural or SSOs feedstocks, even if the price paid for the RNG is sufficient to be profitable.

While this dynamic could affect RNG supply, it is impossible to predict and therefore was not included in the RNG production potential estimations. Furthermore, the following observations may be offered:

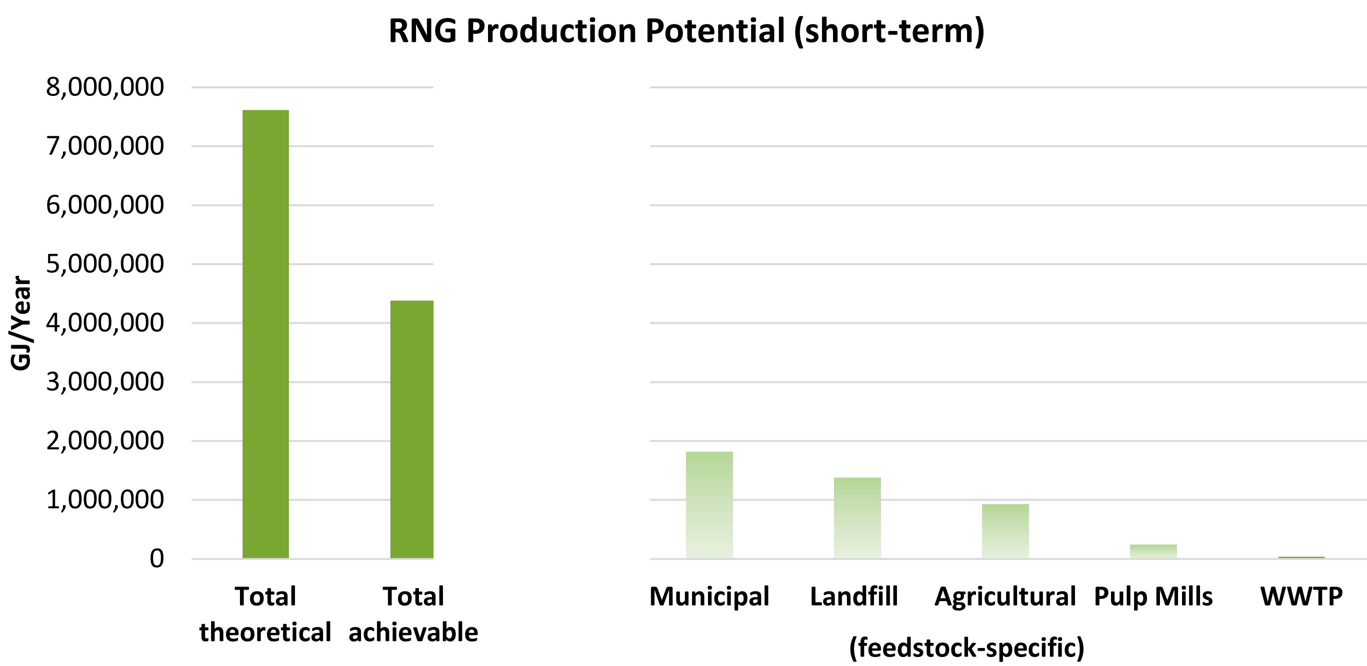
- Larger farms with the majority of the agricultural feedstocks are typically more business orientated and diverse than smaller farms. Furthermore, many on-farm AD plants in the US aren't owned or operated by farmers, but by a third-party. Therefore any 'human factor' will likely have a minimal impact on achievable agricultural RNG production potential; and

[28] This is less of a concern/issue for LFG upgrading, as upgrading technologies generally have ~95% operating capacity.

- As the drive for greenhouse gas (GHG) reductions continue, local government will likely favour AD plants over compost facilities as AD plants result in greater GHG reductions. Therefore any 'human factor' may have a smaller and smaller impact on achievable municipal RNG production potential.

Achievable feedstock-specific RNG production potential in the short-term is greatest for municipal AD plants digesting residential and ICI SSOs, which have potential to produce 1.9 PJ/year. Landfills upgrading LFG to RNG have an achievable short-term RNG production potential of 1.4 PJ/year, while agricultural AD plants digesting manure, litter, and ICI SSOs where available, have an achievable short-term RNG production potential of 0.9 PJ/year. Pulp mill AD plants digesting WAS and WWTPs upgrading biogas to RNG have achievable short-term RNG production potentials of 0.24 and 0.034 PJ/year[29] respectively (Figure 3).

Figure 3: Short-Term RNG Production Potential at $28/GJ



5. Long-Term RNG Production Potential

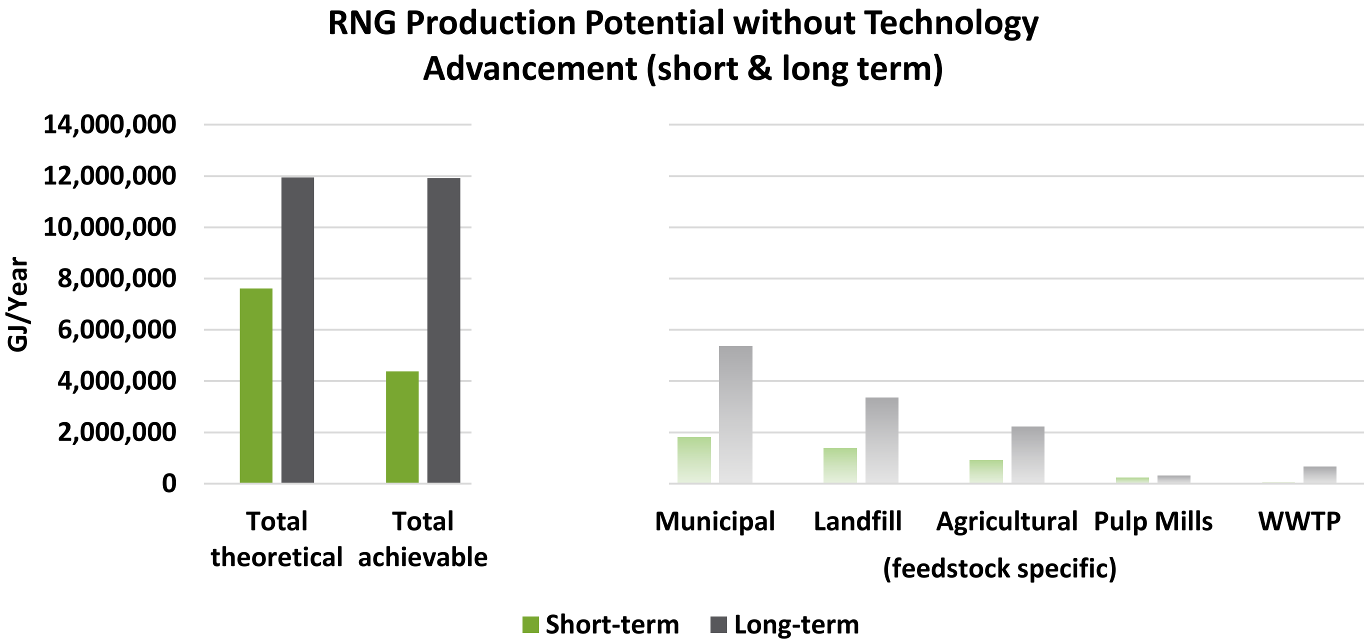
Long-term RNG production potential assuming a market price of $28/GJ was estimated. The long-term was defined as a time in which significant changes in both available RNG feedstocks and wood RNG technology are expected. For the purpose of estimating potential feedstock availability, the year 2035 was chosen.

The first long-term RNG production potential used projected industry and population growth rates to estimate increased feedstock volumes, and assumed no significant advancements in wood RNG technology. It also assumed that WWTPs and landfills currently burning biogas and LFG to produce heat and/or electricity are able to switch to RNG production; as technology and infrastructure originally installed to produce heat and/or electricity was assumed to be close to or beyond retirement age and could therefore be replaced.

[29] The reason for this low RNG production potential is that WWTPs currently burning biogas to produce heat and/or electricity are assumed unable to switch production to RNG in the short-term.

RNG production potential in the long-term assuming a market price of $28/GJ and no significant advancements in wood RNG technology is estimated to be 11.9 PJ/year.[30] The increase in RNG production potential is estimated to occur across all potential sources, with municipal, agricultural, and pulp mill RNG production potential estimated to increase to 5.4, 2.2, and 0.3 PJ/year respectively, and LFG and WWTP RNG production potential estimated to increase to 3.4 and 0.7 PJ/year respectively (Figure 4).

Figure 4: Short & Long-Term RNG Production Potential without Technology Advancements at $28/GJ



The second long-term RNG production potential used estimated feedstock volumes, and assuming a market price of $28/GJ and significant advancements in wood RNG technology. Development of commercially available technologies[31] to convert wood feedstock to RNG will significantly increase B.C.'s RNG production potential. For example, based on available suitable agricultural feedstocks (i.e., horse bedding, broiler litter, and turkey litter) and B.C. Hydro's forestry feedstock estimations, RNG production potential is estimated to be 51.3 PJ/year. If NRCan's forestry feedstock estimations are used, RNG production potential is estimated to be 93.6 PJ/year (Figure 5).

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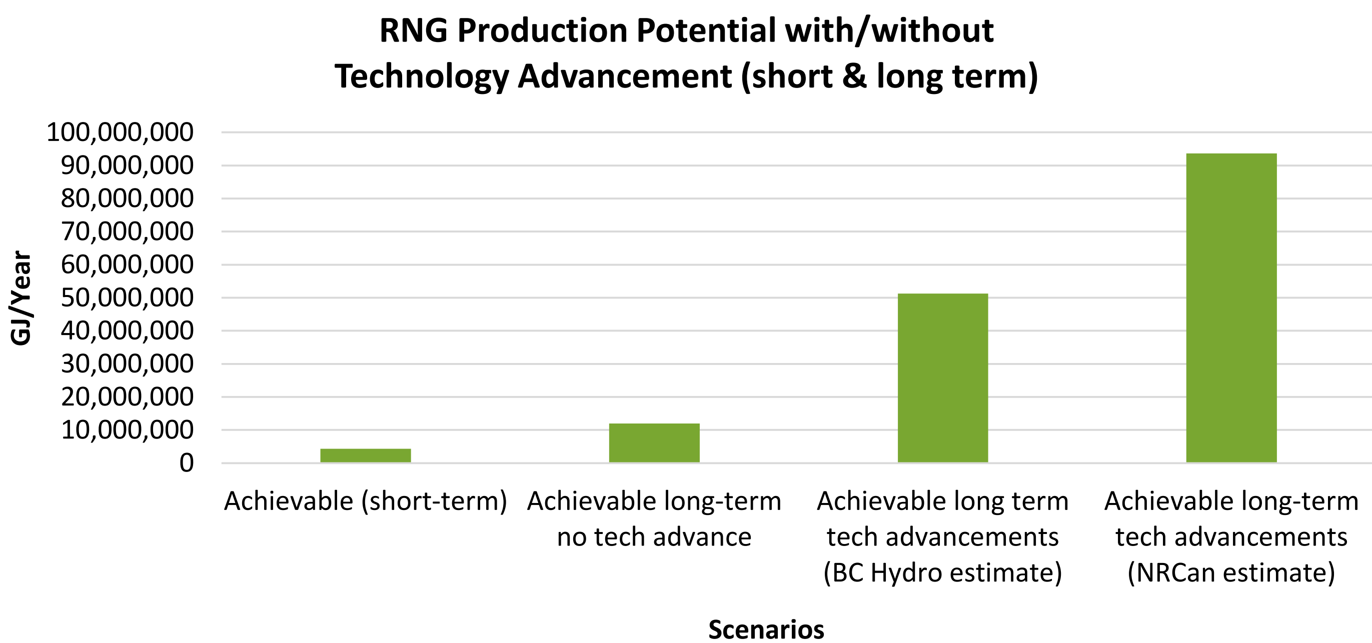
[30] There is little difference between short and long-term theoretical and achievable RNG production potential because improvements in feedstock pre-treatment (increasing RNG production per unit) and more widely implement organic waste separation (increasing availability of SSOs) are assumed to offset the lower operating capacity and feedstock unavailability assumed in the short-term.

[31] Two promising technologies currently demonstrating conversion of wood feedstock into RNG use thermochemical technology to first convert the feedstock into synthetic gas, before transforming the synthetic gas into RNG. A third approach being developed involves using synthetic gas as a gaseous co-digestion feedstock in AD plants to convert carbon monoxide and hydrogen into CH_4. Other technologies being developed include small-scale lignocellulosic pre-treatment technologies, such as catalyzed steam pre-treatment and extrusion technologies, making it possible to use wood feedstock in AD plants.

Figure 5: Short & Long-Term RNG Production Potential with/without Technology Advancements at $28/GJ



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Attachment 51.1

MEMORANDUM OF UNDERSTANDING

between

FortisBC
(Including FortisBC Energy Inc. ("FEI"), and
FortisBC Alternative Energy Service Inc. ("FAES"),
collectively known as "FortisBC")

-and-

The City of Vancouver
("the CoV")

WHEREAS the CoV has adopted their Renewable City Strategy with the goal of improving air quality and reducing greenhouse gas (GHG) emissions by at least 80% below 2007 levels before 2050, which is consistent with Provincial and Federal climate and energy objectives;

AND WHEREAS the CoV has created plans, policies and bylaws, and has made investments to support the Renewable City Strategy;

AND WHEREAS these strategies, plans, policies, and bylaws require continued investment to support timely transformation in the areas of energy efficiency, energy conservation, emissions reductions and the development of renewable energy supply;

AND WHEREAS FortisBC has a portfolio of investments, programs and initiatives that support timely transformation in the areas of energy efficiency, energy conservation, emissions reductions and the development of renewable energy supply;

AND WHEREAS FortisBC is prepared to increase its portfolio of investments, programs and initiatives in Vancouver in support of the Parties' mutual objectives in energy efficiency, energy conservation, emissions reductions and the development of renewable energy supply;

AND WHEREAS the CoV and FortisBC are committed to climate action initiatives that support innovation, safety, reliability, and affordability;

AND WHEREAS the CoV and FortisBC can collectively achieve greater progress towards climate action initiatives by working together;

THEREFORE, the CoV and FortisBC ("the Parties") will pursue the following within the non-legally binding framework of this memorandum in accordance with the principles set out in section 9 and Appendix A:

1. **Increase access to energy efficiency and conservation investment**
   To enable greater access to energy efficiency investment through FortisBC's demand side management (DSM) programs, greater flexibility for new building

developers, and increased alignment with federal and provincial objectives and policy:

a) FortisBC will develop DSM programs to include, where permitted by Provincial DSM Regulation, energy efficiency rebates in alignment with each step of the BC Energy Step Code, by March 31, 2018, subject to BCUC approval. FortisBC will consult with the CoV and other stakeholders in developing its programs.

b) The CoV will create, subject to Council approval, alternative compliance pathways for all building energy and GHG emissions-related policies and bylaws, as follows:

   i. Alternative pathways will be based on the BC Energy Step Code performance requirements and will not include a GHG intensity target.

   ii. Alternative pathways will adopt the step of the BC Energy Step Code that achieves equivalent emissions outcomes to CoV objectives. The CoV may adopt a lower step in order to reach or accelerate the implementation of its objectives.

   iii. The CoV will maintain prescriptive pathways where they align with the requirements above.

   iv. Consequential amendments to the current Green Buildings Policy for Rezoning and Vancouver Building Bylaw (if any) as a result of this memorandum will be recommended to Council for approval by March 31, 2018.

2. Increase investment in Low Carbon Energy Systems (LCES)
In order to increase investment in LCES:

a) The CoV will follow through on its commitments to create a Low Carbon Energy System (LCES) Policy that supports investment and private ownership of LCES. In addition, the City will update existing policies to remove mandated neighbourhood energy system (NEU) connectivity and use to enable third-party thermal energy contracts with the exception of areas served by district energy systems owned by the CoV. Recommendations on the LCES Policy and changes to NEU connection and use requirements will be recommended to Council for acceptance by December 31, 2017.

b) The CoV and FortisBC will continue to identify and pursue opportunities to reduce barriers for LCES.

c) FortisBC will pursue LCES investment opportunities within Vancouver.

3. Improve safety and efficiency of gas furnace retrofit installations
In order to collaboratively improve the ease, quality and safety of installing high efficiency gas furnaces:

a) The CoV will publish a bulletin clarifying venting requirements for high efficiency space heating appliances, including the application of exterior vertical venting, by October 1, 2017.

b) In consultation with FortisBC, the CoV will host a workshop between city staff, FortisBC, and industry by December 31, 2017 to develop alternatives to the current approach to sidewall venting. The scope of the discussion will include additional flexibility under the current bylaw, industry best practices, and the adoption of an updated bylaw aligned with neighboring jurisdictions.

c) Updates to the bylaw or bulletin will be submitted for approval to Council by March 31, 2018.

d) The CoV will maintain a restriction on sidewall venting for high efficiency space heating installations in new construction. Sidewall venting in other gas appliances will remain unrestricted in new and retrofit applications.

e) FortisBC and the CoV will meet periodically to review opportunities to further mitigate noise, moisture and permitting concerns with furnace sidewall venting applications.

f) FortisBC and the CoV will implement a program to educate stakeholders, including natural gas contractors that operate in Vancouver, about safe, efficient and neighbourly installation, venting, and maintenance of furnaces and hot water tanks.

g) FortisBC will continue to require customers to obtain requisite permitting in order to access DSM rebates.

4. Develop a Deep Energy Retrofit Pilot Project

In support of energy efficiency and conservation efforts, the Parties agree to develop a pilot project to demonstrate and enable a deep energy retrofit in a commercial building. The pilot project will strive to:

- Achieve energy savings;
- Achieve emissions reductions;
- Involve other partners and secure other sources of funding; and
- Explore how the pilot could be replicated in the future.

The Parties agree to create a working group, develop a project scope, cost-benefit analysis, cost-sharing arrangement and targeted energy and emission savings. The working group will submit a viable project to their respective principals for approval and implementation.

5. Development of renewable energy supply and usage

In support of GHG reduction initiatives:

a) The Parties will continue to pursue and attempt to conclude an agreement for the Vancouver Landfill Renewable Natural Gas (RNG) supply project provided they are able to agree on terms that are satisfactory to, and align with the respective policies of, each Party.

b) The CoV will follow through on its commitment to develop an internal corporate carbon pricing policy that will provide a framework to assess the use of RNG, and other low carbon solutions, in CoV buildings, fleets and neighbourhood energy utilities by December 31, 2017 subject to Council approval. The CoV will consult FortisBC and other stakeholders on the development of the policy.

c) The Parties will continue to pursue and attempt to conclude a commercial agreement that allows the CoV to increase the use of RNG in CoV buildings, CoV fleets and CoV neighbourhood energy utility provided they are able to agree on terms that are satisfactory to, and align with the respective policies of, each Party.

d) FortisBC is committed to investing in additional RNG supply projects throughout BC in alignment with Provincial legislation.

e) The Parties will review and identify other potential RNG supply and usage projects in Vancouver.

f) The CoV and FortisBC will work cooperatively in the identification, and development of future RNG supply and usage projects with various governmental bodies.

g) FortisBC and the CoV will develop and implement a workshop for CoV staff on emerging RNG innovations and policy best practices by December 31, 2017. The scope of the workshop could include other gas grid innovations such as hydrogen.

6. Improving local air quality and reducing GHG emissions in transportation

In order to improve local air quality, promote emissions reductions, and promote the adoption of lower carbon energy infrastructure in the transportation sector:

a) FortisBC will assist the CoV in developing its business case for optimizing the use of its compressed natural gas station by October 31, 2017.

b) FortisBC is committed to pursuing the use of natural gas for transportation (NGT) in medium and heavy duty, rail and marine applications in alignment with Provincial legislation.

c) The CoV will support FortisBC in the ongoing development and deployment of NGT with other governmental bodies where the deployment reduces GHG and local air emissions relative to currently viable alternatives and where the deployment represents a reasonable step towards climate objectives.

d) FortisBC will involve the CoV in existing working groups to assess and support the opportunity to reduce emissions through the use of natural gas for yard tractors, drayage trucks and marine bunkering at the Port of Vancouver and in Vancouver by October 31, 2017.

e) FortisBC and the CoV will develop and implement a workshop for CoV staff on emerging NGT innovations, policy best practices and identifying fleet opportunities at the CoV by December 31, 2017 and may include annual updates as necessary.

7. Ongoing collaboration

In support of this memorandum and in future collaboration:

a) The relationship principles, management structure, and key contacts relating to this memorandum are contained in section 9 and Appendix A.

b) FortisBC commits, under the FortisBC Climate Action Partnership Pilot Project, to fund (or provide, subject to mutual agreement) a two-year, temporary, full time CoV position in order to enable the implementation of initiatives described in this memorandum. The Parties will develop and agree on the work plan for this position.

8. Public Communication

The Parties value transparency and accountability. Accordingly, each Party intends to communicate the benefits of this memorandum publicly and will coordinate all communications in respect of the activities contemplated by this memorandum in accordance with the protocol as set out below:

a) The Parties will identify opportunities to jointly promote this memorandum and the projects flowing from it.

b) The Parties will consult with each other in order to align messaging regarding this memorandum.

c) Except as required by a regulator or by law, neither Party will make public statements about initiatives arising from this memorandum without obtaining express permission of the other party prior to doing so, which will not be unreasonably withheld.

d) Communications activities may include, without limitation, major public events or announcements, or communications products such as speeches, press releases, websites, social and digital media, advertising, promotional material or signage.

e) The Parties agree that joint communications activities marking the signing of this memorandum and other key milestones will involve both Parties in their planning and execution.

f) In addition to joint communications activities, the Parties may include messaging in their own communications products and activities.

g) The Parties will make reasonable efforts regarding the timing of public events to allow for the Parties to plan their involvement.

9. Term, dispute resolution, principles and other conditions

a) This memorandum shall have an initial term of 5 years from the date of its signing; however, it may be revised by written agreement as needed.

b) Each Party recognizes, and is respectful of the fact that, FortisBC's Board of Directors where approval is required and the CoV's City Council have ultimate discretion over any initiative outlined in this memorandum. The CoV also recognizes that some initiatives may be subject to regulatory approval. The Parties recognize that the exercise of discretion above will be guided by, amongst other things, the need to be accountable to their stakeholders, constituents and customers, as the case may be.

c) Should a Party fail to receive approval from its Board of Directors, the regulator or Council, where required, on any items contained in this memorandum, the Parties will meet to discuss alternatives and agree on a revised proposal for submission or alternative resolution for implementation.

d) Specific dates set out in this memorandum are intended as target dates which the Parties will work to achieving, on a commercially reasonable efforts basis.

e) The Parties will design and conduct the activities contemplated by this memorandum in accordance with applicable laws.

f) Should a dispute arise concerning the application of this memorandum, the issue will be resolved through escalation to the executive sponsors.

g) When pursuing an initiative together, the Parties recognize they may need to negotiate and enter into separate legally binding agreements to document the specific terms and conditions of such initiative.

h) With the exception of the terms directly below, this memorandum represents a non-legally binding framework for enhanced collaboration between FortisBC and the CoV.

i) This memorandum is not an exclusive arrangement and does not restrict either Party from pursuing its mandates, either on its own, or in collaboration with any other party.

j) Each Party is to bear its own costs in relation to this memorandum unless otherwise set out in a separate written agreement.

k) This memorandum does not grant any right to either Party to use each other's logos, trademarks or other intellectual property. Any such use will only be permitted through a legally binding written agreement between the Parties.

SIGNED this 22 day of September, 2017

City of Vancouver

Sadhu Johnston, City Manager

FortisBC Energy Inc.

Doug Stout, VP, Market Development and External Relations

FortisBC Alternative Energy Services Inc.

Doug Slater, General Manager

APPENDIX A

1. Relationship Foundation Principles

The Parties agree to the following guiding principles in support of their ongoing relationship:

a) Ensuring a respectful and collaborative approach to building and maintaining a productive relationship.

b) Assignment of a point person to assist in ongoing engagement and communication.

c) Ongoing engagement and work towards common initiatives.

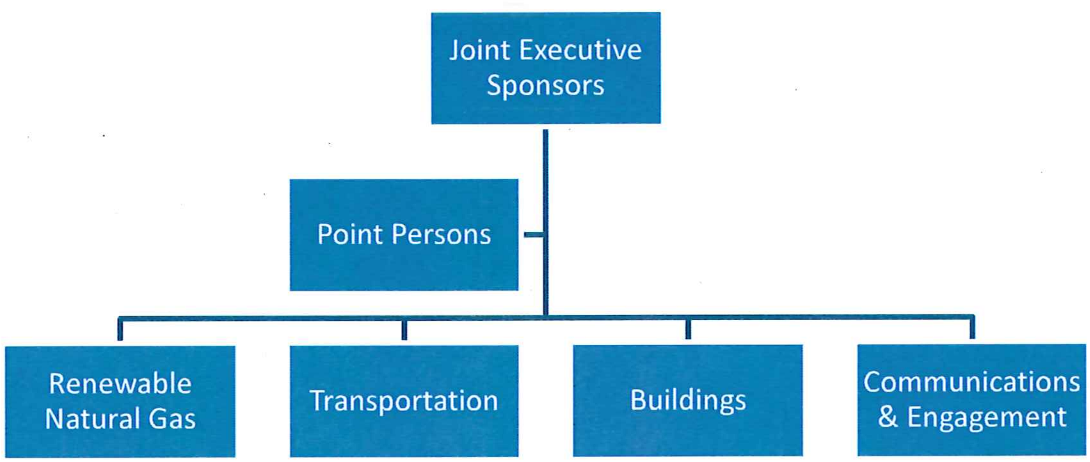
d) Regular meetings in order to maintain lines of communication and collaboration.

e) Make every effort to resolve issues at the lowest staff level possible before escalating an issue to the point persons and executive sponsors.

f) Endeavor to provide each other with advanced notice of communications concerning common issues.

2. Management Structure

The management structure for this memorandum is outlined in the chart below:



3. Key Contacts

	City of Vancouver	FortisBC
Executive Sponsors	Sadhu Johnston, City Manager	Doug Stout, VP Market Development and External Relations
Point Persons	Matt Horne, Manager Climate Policy	Brent Graham, Manager, Public Policy
Renewable Natural Gas		
Supply	Brian Beck, Strategic Projects Engineer	Sarah Smith, Director NGT & Regional LNG
Demand	Doug Smith, Acting Director, Sustainability	Jason Wolfe, Director, Energy Solutions
Transportation		
Fleet	Amy Sidwell, Manager, Equipment Services Branch	Sarah Smith, Director NGT & Regional LNG
Port of Vancouver	Matt Horne, Manager Climate Policy	Brent Graham, Manager, Public Policy
Buildings		
Existing	Sean Pander, Manager, Green Building Manager	Danielle Wensink, Director, C&EM
New Construction and Rezoning	Sean Pander, Manager, Green Building Manager	Jason Wolfe, Director, Energy Solutions
LCES	Sean Pander, Manager, Green Building Manager	Doug Slater, General Manager, FAES
Communications & Engagement		
Communications	Rena-Kendall-Craden, Director, Communications	David Bennett, Director, Communications & External Relations
Intergovernmental Relations	Marnie McGregor, Director, Intergovernmental Relations & Strategic Partnerships	David Bennett, Director, Communications & External Relations

Attachment 51.1

CITY OF VANCOUVER

POLICY REPORT
DEVELOPMENT AND BUILDING

Report Date:	April 20, 2018
Contact:	Patrick Enright
Contact No.:	604.871.6158
RTS No.:	12332
VanRIMS No.:	08-2000-20
Meeting Date:	May 2, 2018

TO: Standing Committee on City Finance and Services

FROM: General Manager of Planning, Urban Design, and Sustainability, in consultation with the Chief Building Official

SUBJECT: Energy and Water Efficiency Updates to the Building By-law and Rezoning Policy

RECOMMENDATION

A. THAT Council approve, in principle, amendments to the Building By-law generally in the form attached as Appendix A, including:

i. Energy efficiency and airtightness requirements for residential buildings over 6-storeys and commercial buildings that align with:
   1. Step 2 of the BC Energy Step Code, and greenhouse gas limits, beginning in June, 2019;
   2. Step 3 of the BC Energy Step Code, and with the limits in the current Green Buildings Policy for Rezonings, beginning in June, 2021;

ii. Energy efficiency requirements, previously approved by Council for 4-6 storey residential buildings, to also be applied to mixed-use residential buildings up to 6-storeys, where commercial uses may be present on the first and second storey, including preserving both a prescriptive and a performance option;

iii. Creating alternate compliance pathways to these requirements, where a development may choose a higher Step of the BC Energy Step Code in lieu of a GHG limit;

iv. Energy efficiency requirements for all other building types that reference the most up-to-date North American energy standards for buildings, as required by the upcoming updates to the base BC Building Code, provisional upon Provincial approval of those updates; and

v. Addressing minor housekeeping changes to past updates, and the removal of drain water heat recovery requirements pending further implementation research and industry education;

FURTHER THAT that the Director of Legal Services be instructed to prepare the necessary amending by-law generally in accordance with Appendix A.

B. THAT Council approve, in principle, amendments to the Building By-law generally in the form attached as Appendix B, to enhance water efficiency requirements pertaining to plumbing fixtures, appliances and equipment in all building types;

FURTHER THAT that the Director of Legal Services be instructed to prepare the necessary amending by-law generally in accordance with Appendix B.

C. THAT Council approve amendments to the Green Buildings Policy for Rezonings attached as Appendix B, including:

i. A change to the heat loss limit for residential buildings over 6-storeys from 32 to 30, to align with Step 3 of the BC Energy Step Code;

ii. Creating alternate compliance pathways, where a development may choose a higher Step of the BC Energy Step Code, or Passive House, in lieu of a GHG limit; and

iii. The addition of low-VOC materials, and energy metering and reporting requirements, for buildings pursuing the near-zero emissions building pathway (e.g. Passive House).

REPORT SUMMARY

This report proposes energy efficiency improvements to the Building By-law that represent the last of the initial changes to policy and regulation identified in the Zero Emissions Building Plan (ZEBP). The BC Energy Step Code grew out of the same research and collaborations that created the ZEBP and uses most of the same metrics. This makes it simple to align energy efficiency improvements with the BC Energy Step Code while it is also being adopted by neighbouring local governments.

This report also recommends water efficiency updates to the Building By-law that will reduce the impact of growing communities on City infrastructure.

Finally, this report recommends minor improvements to the Green Buildings Policy for Rezonings.

These proposed changes together provide:

- Improved indoor air quality, thermal comfort, and soundproofing in new buildings
- Alignment with requirements being adopted by other local governments and utility incentive programs
- Clear direction on future requirements for industry
- Reduced greenhouse gas emissions by up to 66% compared to current code
- Reduced energy costs between 2% to 23% compared to current code
- Increased construction costs of 1% or less for developers

Aligning these updates with the BC Energy Step Code will build industry capacity and lower future costs, enabling the future adoption of zero emissions and net zero energy ready buildings in Vancouver and across BC.

COUNCIL AUTHORITY/PREVIOUS DECISIONS

In June 2008, as part of the Green Homes Program, Council adopted Building By-law amendments for new one- and two-family dwellings requiring air tightness testing and heat recovery ventilation.

In April 2014, Council adopted the 2014 Building By-law that further increased the energy efficiency requirements for single-family homes through increased prescriptive requirements for walls, windows, mechanical equipment and airtightness. Large buildings were required to use the most up-to-date North American energy standards for buildings.

In July 2016, Council approved the Zero Emissions Building Plan that included time-stepped GHG emission and energy efficiency limits for each building type for inclusion in policies and the Building By-law.

In November 2016, Council approved changes to the Green Buildings Policy for Rezonings, establishing GHG emissions and energy efficiency limits on rezoned buildings while also requiring air tightness testing and direct ventilation. This policy also allows Passive House certification as an alternative compliance pathway.

In February 2017, Council adopted a Building By-law amendment to extend the prescriptive energy efficiency measures in single-family homes to all residential buildings up to 6 storeys. For 4-6 storey residential buildings, it also provided a performance option that has GHG emissions and energy efficiency limits.

In April 2017, Council adopted enhanced water efficiency measures for the Vancouver Building By-law and the Water Works By-law. Council also directed staff to review opportunities to further strengthen performance requirements for commercial and household fixtures and appliances.

CITY MANAGER'S/GENERAL MANAGER'S COMMENTS

The City Manager supports these recommendations to reduce energy costs and emissions, improve indoor air quality, comfort, and water efficiency, and align with provincial standards for energy efficiency being adopted by other local governments in the Lower Mainland.

REPORT

Background/Context

<u>BC Energy Step Code</u>

The BC Energy Step Code is a voluntary provincial standard for energy-efficient buildings that go beyond the requirements of the base BC Building Code. It grew out of the same research and collaborations that created the ZEBP, establishing stepped, performance-based limits on energy use and heat loss by building type that communities may voluntarily choose to adopt in bylaws and policies. Lower steps are intended to be adopted sooner and into by-law, with upper steps intended for rezoning, density bonus programs, or future adoption into by-law.

Figure 1: Structure of the BC Energy Step Code

To create, support, and advise on implementation of the BC Energy Step Code, the Province established the multi-stakeholder Energy Step Code Council. The Energy Step Code Council is made up of local governments, industry associations, utilities, and representatives from the provincial and federal government. Members include UDI, UBC, GVHBA, BC Hydro, Fortis BC, BC Housing, AIBC, EGBC, Natural Resources Canada, and many others.

Across BC over 23 local governments have already indicated they will consult on adoption of the BC Energy Step Code. Of those, the District of West Vancouver, the District of North Vancouver, and the City of North Vancouver have formally adopted Step 2 for large residential buildings, forming an alignment of energy requirements across the North Shore. The City of Richmond is actively consulting on adopting Step 3 immediately for large buildings, and the City of Victoria and District of Saanich are consulting on adopting Step 3 by 2020.

Zero Emissions Building Plan

The BC Energy Step Code was developed at the same time, with many of the same stakeholders, and with a very similar approach as the Zero Emissions Building Plan ("ZEBP"). Both set stepped limits on total energy use and heat loss by building type, are calculated using the City of Vancouver Energy Modelling Guidelines, include measures for airtightness and improved ventilation, and set goals of zero emissions or net-zero ready new buildings by 2030 (Vancouver) or 2032 (BC) respectively.

In addition, Policy and By-Law amendments to implement the ZEBP establish GHG limits for new buildings, and the plan establishes a timeline for these limits to step down at regular intervals. Including a GHG limit requires new buildings to use fossil fuels efficiently or only if they are needed. As higher steps of the Step Code are adopted a GHG limit also enables a choice of two pathways for compliance, both with the same GHG limits, each prioritizing either envelope efficiency or professionally maintained technology (a "LCES pathway").

To step down limits over time, the ZEBP establishes a strategy of using the rezoning process to set new levels of energy performance, to be followed by similar building code requirements five years later. This allows industry leaders to normalize best practices and suppliers to prepare for future code changes. The outcomes of the preceding Green Buildings Policy for Rezonings, which was in place from 2011, are roughly equivalent to Step 2 of the BC Energy Step Code, priming them for adoption into the building code immediately. In 2016 the first performance limits under the ZEBP were established in the rezoning policy and roughly align with Step 3, and industry is already expecting these limits to enter the building code by 2021.

Water Efficiency

In 2017, the City of Vancouver used less total drinking water than in 1986, despite having a 50% larger population. The City's objective for water efficiency and conservation is to promote the sustainable use of the current water supply, aspiring to completely offset population and economic growth and defer, limit or avoid the financial, environmental and social costs associated with expanding water and sewer infrastructure to increase capacity. While our "per person" overall consumption has dropped 18% since 2006, we still use 66 litres more per person per day compared to drier, hotter Los Angeles.

This report proposes to update plumbing fixture, appliance and equipment standards in new construction and substantial renovations of all building types to increase water efficiency.

Strategic Analysis

The BC Energy Step Code

a) Benefits

According to the BC Energy Step Code Best Practices Guide for Local Governments, published by the Energy Step Code Council and the Building Safety Standards Branch, buildings built to higher energy efficiency standards provide multiple benefits – to homeowners and occupants, to industry, and to the community.

For home-owners and residents, these buildings:

- Better manage temperature, improving comfort.
- Better manage fresh air throughout the building, improving health.
- Better manage soundproofing, reducing exterior noise.
- Require less energy, reducing utility bills.

For industry, a standard set of metrics and requirements creates a new level of consistency and predictability across local governments. And by providing clear timelines for future updates, the industry can invest in developing products, services, and best practices to deliver competitive and cost-effective services and products for high-performance buildings.

For communities, clear direction and leadership in energy policy can strengthen the local green economy, while also reducing contributions to climate change.

b) Cost Analysis

The impacts of the BC Energy Step Code were comprehensively studied and published in the BC Housing 2017 Metrics Research Report. The study was produced for BC Housing and the BC Building and Safety Standards Branch, with the support of Natural Resources Canada. The BC Housing Metrics Study used dozens of energy conservation measures and millions of energy models, with costs sourced from multiple projects and vetted by industry members, to find the lowest cost options to achieve each step. Table 3 shows the lowest incremental costs for Vancouver.

A second costing report created by UBC for their own buildings supports the conclusions of the BC Housing Metrics Study. This study focused in even greater detail on residential buildings in Vancouver. The study found the lowest cost options to be the same or lower than the BC Housing report, while the average costs may be slightly higher. The average costs for each step are shown in Table 3.

Historically, updates the Building By-law have aimed to keep cost increases below 2%, and the available studies show Step 2 and 3 are generally achievable at cost increases of 1% or less.

Table 3: Incremental Costs for Vancouver

Building Type	Step	Lowest Incremental Cost (BC Housing Report)	Average Incremental Costs (UBC Report)
High-Rise Multifamily	2	0.4%	0.6%
	3	0.8%	1%
Commercial Office	2	0.2%	Not in Scope
	3	0.2%	
Retail	2	0.8%	
	3	1.2%	

Both the BC Housing Metrics Study and the UBC Study found significantly positive net present values and internal rates of return for Step 2 and 3. In an additional analysis by staff, both Step 2 and 3 were found to save money on a monthly basis for residents, with any incremental costs to a monthly mortgage being offset by energy savings. This remains true for Step 3 even when achieving the GHG limits of the Zero Emissions Building Plan, and even when considering the higher average incremental cost from the UBC Report (refer to Appendix D for detailed calculations).

As a result of the long-term value of energy efficiency, BC Housing requires any new BC Housing projects in the Lower Mainland to be built to at least Step 3.

Energy Efficiency Updates

a) Large Residential and Commercial Buildings – Align with BC Energy Step Code

The proposed changes continue the implementation of the Zero Emissions Building Plan by creating performance-based GHG, heat loss, energy use limits, and new requirements for airtightness and ventilation, for large residential and commercial buildings. These changes will align the Building By-law with the BC Energy Step Code being used by neighbouring local governments, with the addition of a GHG and an airtightness limit. These changes are summarized in Table 1 below, and the full text of the proposed changes are included in Appendix A.

Table 1: Summary of Proposed Changes for Large Residential and Commercial

Change	Description
Energy Performance	• Set greenhouse gas, heat loss, and energy limits for large residential and commercial buildings, while aligning with the heat loss and energy use limits of the BC Energy Step Code. • No prescriptive path; buildings must have an energy model.
Direct Ventilation	• Outdoor air must be supplied directly to each suite by mechanical ventilation through ducting.
Whole-Building Airtightness	• All buildings and major occupancies must be tested for airtightness. • All buildings must meet an airtightness target of 2.0 L/s/m² @ 75Pa, or be sealed to the satisfaction of the Chief Building Official.
Suite Airtightness	• Residential suites must meet be tested and achieve an airtightness target of 1.2 L/s/m² @50Pa

The proposed changes align with the heat loss and energy use limits of Step 2 of the BC Energy Step Code, and the outcomes of the 2011 Green Buildings Policy for Rezonings, beginning in June, 2019. Beginning in June, 2021, these limits will change to align with Step 3 of the BC Energy Step Code, and the greenhouse gas limits of the 2016 Green Buildings Policy for Rezonings.

As an alternative to the greenhouse gas limits, the proposed changes also include a compliance pathway that allows the heat loss and energy use limits of a higher step to be followed. This alternative allows some flexibility for projects that may require it, while still having a likely similar greenhouse gas outcome, and demonstrating techniques to achieve the next step in performance.

As the performance requirements increase to align with Step 3 and the Green Buildings Policy for Rezonings, a Low Carbon Energy System pathway will also be included in the Building By-law. This provides developments the opportunity to balance their investment in envelope and ventilation improvements with the use of professionally maintained and operated energy systems, whether at the site or district scale.

b) Mixed-use Residential Up to 6 Stories – Align With Recent Changes for 4-6 Storey Residential

This report proposes changes to align the energy efficiency requirements for mixed-use buildings up to 6 storeys with those approved in February 2017 for 4-6 storey purely residential buildings, including preservation of both the prescriptive and performance pathways. This means that mixed-use residential buildings up to 6 stories, such as those with commercial space at grade, will have access to the same compliance options and requirements as a purely residential building of the same height. To accommodate commercial uses, a less stringent requirement is included for storefront glazing and doors, where high-performance glazing options can be limited or more costly. As previously reported to Council, these changes were specifically developed to result in cost savings on a monthly basis for residents.

c) All Other Building Types – Align with Upcoming Base BC Building Code

The BC Energy Step Code currently only has performance targets for residential, office, and commercial. For all other building types, the BC Building Code is proposing to reference the most up-to-date versions of North American energy standards. The Building By-law is required to meet or exceed the requirements of the BC Building Code, and so the references to ASHRAE 90.1-2010 and the National Energy Code for Buildings (NECB) 2011 will be updated to 2016 and 2015 respectively.

Water Efficiency Updates

The proposed updates will reduce water consumption and sanitary sewer flows from new homes by an average of 3%. The cost implications are as follows:

- 80% of new homes: no additional capital cost as these already include Energy Star appliances.
- 20% of new homes: about $50 - $200 additional capital cost to upgrade to Energy Star, with ongoing savings in utility bills and a recovery of the price differential within a maximum of four years.
- City of Vancouver: no additional capital cost and ongoing operations and maintenance savings.

These updates apply to new construction and substantial renovations of buildings of all types. The proposed amendments harmonize with the 2018 British Columbia Plumbing Code revisions. For fixtures, appliances and equipment not addressed by the 2018 British Columbia Plumbing Code, amendments were developed by considering regulatory requirements of other jurisdictions, international green construction codes, market research, stakeholder input, and economic and environmental costs.

a) Fixtures

For residential kitchen faucets, a maximum flow rate of 6.8 litres per minute (L/min) is proposed (non-residential kitchen faucets would remain unchanged at 8.3 L/min).
To align with the revised 2018 British Columbia Plumbing Code, public use lavatory faucets and public use shower heads will be required to turn off automatically after use.

b) Mechanical Systems and Equipment

Single pass systems such as once through cooling are prohibited by the Water Works By-law (Section 3.9). An administrative amendment is proposed to include this language in the more visible Building By-law. It is also proposed to prohibit the use of drinking water to temper steam condensate and other discharges.

c) Appliances

The following appliances are proposed to be Energy Star certified or an acceptable equivalent: clothes washers (residential and commercial), dishwashers (residential and commercial), ice makers, commercial steam cookers and combination ovens. In 2015, 79% of residential clothes washers and 96% of residential dishwashers shipped to British Columbia and the Territories were already Energy Star certified.

For all of the residential appliances addressed in this proposal, there is a net savings over the appliance's life cycle. When there is a price differential for an Energy Star appliance compared to a non-certified appliance, this is recovered by the owner in less than four years, which is under the typical ownership cycle of seven years for a condominium and ten years for a single family home. For the commercial appliances covered by this proposal, any purchase price differential for the Energy Star appliance is recovered for nearly all of the categories (Appendix E).

Changes to the Green Buildings Policy for Rezonings

This report proposes minor changes to the Green Buildings Policy for Rezonings, summarized in Table 2.

These changes have negligible cost, with multiple benefits. The addition of energy metering and reporting to Option A allows the City to understand the real world outcomes of Passive House projects once they are completed. Low VOC materials are often specified but not explicitly required in Option A, and these requirements extend improvements to indoor air quality to all rezoning buildings. Changing the heat loss limit to align with the BC Energy Step Code creates one number province-wide for this level of performance, and can make these projects eligible for utility incentives that align with the Step Code.

Table 2: Summary of Proposed Changes for Rezonings

Compliance Option	Description
Option A – Near Zero Emissions Buildings (i.e. Passive House Certified)	• Add requirements for energy metering and reporting to match those already in Path B. • Add requirements for low VOC materials to match those already in Path B.
Option B – Low Emissions Green Buildings	• Change the heat loss limit (TEDI) for 7+ storey MURBs to 30 from 32 to align with Step 3 of the BC Energy Step Code. • Add an additional compliance path that aligns with a higher step of the Energy Step Code, without a GHGI limit.

As noted for the Building By-law, an alternative compliance pathway allows some flexibility for projects that require it, while still having a likely similar greenhouse gas outcome, and demonstrating techniques to achieve the next step in performance.

Consultations

Energy efficiency updates to the building by-law that reflect previous rezoning outcomes, and future updates based on a new rezoning policy, were first signalled to industry in the ZEBP in July 2016. Consultations with industry on the proposed energy efficiency changes to the building by-law and rezoning policy began with the development industry in June 2017, and proceeded throughout the summer and fall.

This initial notification period culminated in a written consultation letter that summarized all proposed changes that was issued widely to industry at the beginning of January, with recipients including AIBC, APEGBC, UDI, GVHBA, Building Safety Standards Branch and the Province of BC, HPBAC, Fortis BC, BC Hydro, BC Housing, Greater Vancouver Board of Trade, and many others. In January and February of 2018, staff hosted three 2.5-hour townhall consultation sessions, where detailed information on the proposed changes was presented and participants could ask questions and discuss with staff.

Feedback from participants was collected through discussions in the townhall sessions, through direct discussions with key stakeholders, and through written feedback sent to green.buildings@vancouver.ca. Following the townhall sessions and response period, a final consultation letter was sent to stakeholders in March describing what we heard, and how proposals would be adjusted before presentation to Council.

Responses were generally quite supportive of the direction and of the specific changes proposed. Staff heard that Step 3 is achievable, that some projects are already pursuing Step 3 levels of performance, and those projects are finding solutions that work for them. Staff also heard that there are still some uncertainties around the most cost-effective ways to achieve Step 3, and it was recommended that more time be allowed for industry to gain experience with applying these solutions in more cases.

In response to these recommendations, the proposed changes have been adjusted from the original proposals to allow more time before implementation. A year is provided between presentation of these changes to Council and their effective date of June 3, 2019. This allows time for development applications that are already in-stream or about to be submitted to either proceed unchanged, or to have adequate time to adjust their design. The effective date for Step 3 with a greenhouse gas limit was changed to June 1, 2021, to allow time for industry to learn from the current Green Buildings Policy for Rezonings. This timing is also consistent with the Zero Emissions Building Plan, which seeks to have the rezoning policy lead the building by-law by five years.

Consultation on water efficiency proposals has been conducted since 2016, and was included in the March final consultation letter to stakeholders, with implementation proposed for January 1, 2019. A small number of household appliance manufacturers objected to the Energy Star requirement for residential clothes washers and residential dishwashers. Their primary appeal is to default to the minimum energy-performance standards (MEPS). The use of Energy Star appliances is already common practice in new developments throughout the City, and there is wide selection and market availability of these appliances. Numerous developers consulted indicated that they did not perceive any significant price difference for Energy Star appliances.

Implementation Support

Implementation of the BC Energy Step Code has been heavily supported to date and will continue to be for the foreseeable future by the Energy Step Code Council and its many members. BC Housing has led this effort to date, producing four hour-long recorded education sessions on the Energy Step Code, coordinated the Build Smart Speaker Series of talks throughout the province to educate industry on the Energy Step Code, published the Design Guide to the BC Energy Step Code, the Illustrated Guide to Achieving Airtight Buildings, the Builders Guide to the BC Energy Step Code, and many other resources. With the upcoming 2018 BC Building Code, the Province is also expected to carry out information sessions and training on all changes included in the next code.

If the proposed updates are approved, City staff will coordinate with provincial efforts to educate the industry in Vancouver on the changes well in advance of their becoming effective next year, beginning with outreach this summer. Sustainability staff will also work internally across the City to coordinate with and support planning and by-law review staff on what changes are coming, what materials to provide to prospective or in-stream applicants, and how to process and review future submissions.

Sustainability staff will continue to monitor and support the energy review process beyond the implementation period, and work to ensure the proper tools and resources are in place for effective compliance. For example, sustainability has recently developed webpages pertaining specifically to all new energy requirements, with the intention to support all aspects of design and permitting. Sustainability supports energy review and compliance efforts, and as energy and emissions requirements are increasingly integrated into the by-law this support may need to be expanded. Sustained support for enforcement will help to secure the full benefits of these proposed changes are achieved.

Implications/Related Issues/Risk

Financial

There are no financial implications.

Human Resources/Labour Relations

There are no human resources / labour relations implications.

Environmental

The recommended Policy updates will reduce GHG emissions in new buildings by up to 25% in 2019, increasing to up to 70% in 2021. Residential water consumption in new homes will be reduced by 3%.

Legal

The Vancouver Charter authorizes Council to enact by-laws for regulating the construction of buildings where the conservation of energy or water, or the reduction of greenhouse gases is concerned.

CONCLUSION

This report proposes energy efficiency improvements to the Building By-law that complete the initial implementation of the Zero Emissions Building Plan (ZEBP) and enhance water efficiency requirements, as well as rezoning policy changes. If approved, these proposed changes will simplify compliance for industry in region, reduce costs, greenhouse gas emissions and water use, and further enable the future adoption of zero emissions and net zero energy ready buildings in Vancouver and across BC.

* * * * *

Draft By-law to amend Building By-law No. 10908
Regarding Energy Efficiency

Note: A by-law will be prepared generally in accordance with the provisions listed below.

1. This by-law amends the indicated provisions of Building By-law 10908.

2. In Book I, Division B, Part 1, Article 1.3.1.2., in Table 1.3.1.2.(1) Council:

(a) adds, in correct alphanumeric order:

"

ASTM	E 779-10	Standard Test Method for Determining Air Leakage Rate by Fan Pressurization	10.2.2.21.(1)
USACE	USACE	Air Leakage Test Protocol for Building Envelopes, Version 3	10.2.2.21.(1)

"

; and

(b) strikes:

"

CoV	2017	City of Vancouver Energy Modelling Guidelines	10.2.2.3.

"

and substitutes:

"

CoV	2017	City of Vancouver Energy Modelling Guidelines	10.2.2.5.

"

; and

(c) strikes:

"

CSA	CSA B55.1-15	Test Method for Measuring Efficiency and Pressure Loss of Drain Water Heat Recovery Units	10.2.2.11.(3)
CSA	CSA B55.2-15	Drain water heat recovery units	10.2.2.11.(3)

".

3. In Book I, Division B, Part 10, Article 10.2.1.3. Council:

(a) strikes out Sentence (1)(b)(ii), and substitutes:

"ii. Energy standards as per Articles 10.2.2.2. or 10.2.2.3., and thermal insulation conforming with 10.2.2.6.,windows and doors conforming with 10.2.2.7., and be provided with heat recovery ventilators conforming with 10.2.2.17.,"; and

(b) strikes out Sentences (1)(i), (j) and (k) and substitutes:

"i) conform with Article 10.2.2.15. where domestic gas fireplaces are provided,
j) provide documentation in conformance with Article 10.2.2.20, and
k) provide airtightness testing in accordance with Article 10.2.2.21.".

4. In Book I, Division B, Part 10, Article 10.2.1.4. Council:

(a) strikes out Sentence (1)(i), and substitutes:

"i) be provided with and heat recovery ventilators in conformance with Article 10.2.2.17.,";

(b) strikes the word "and" from Sentence (1)(j);

(c) strikes the words "and a rating system audit" from Sentence (1)(k) and adds the word ", and" after "10.2.2.20."; and

(d) adds a new Sentence (1)(l) as follows:

"l) provide airtightness testing in accordance with Article 10.2.2.21.".

5. In Book I, Division B, Part 10, Article 10.2.1.5. Council:

(a) strikes out Sentence (1)(h), and substitutes:

"h) be provided with heat recovery ventilators in conformance with Article 10.2.2.17.,";

(b) strikes the word "and" from Sentence (1)(i);

(c) strikes the words "and a rating system audit" from Sentence (1)(j) and adds the word ", and" after "10.2.2.20."; and

(d) adds a new Sentence (1)(l) as follows:

"l) provide airtightness testing in accordance with Article 10.2.2.21.".

6. In Book I, Division B, Part 10, Article 10.2.2.5., Council strikes the title "**Building Envelope Opaque Elements and Simulation Performance**", and replaces it with "**Building Energy and Emissions Performance**".

7. In Book I, Division B, Part 10, Article 10.2.2.7., Table 10.2.2.7.(1), Council adds the following in a new cell located immediately above the cell for "Skylights, roof window and sloped glazing systems":

"

Skylights larger then 1220mm in two directions	2.95

".

8. In Book I, Division B, Part 10, Article 10.2.2.8.(2), Council:

(a) strikes the word "and" at the end of Sentence (2)(d);

(b) strikes the "." at the end of Sentence (2)(e) and substitutes ", and"; and

(c) adds a new Sentence (2)(l) as follows:

"f) a building pursuing certification with the Passive House (PHI) standard.".

9. In Book I, Division B, Part 10, Article 10.2.2.11., Council:

(a) in Sentence (1), strikes out the words "except *row housing* that have no natural gas appliances";

(b) strikes Sentence (2); and

(c) strikes Sentence (3).

10. In Book I, Division B, Part 10, Article 10.2.2.12., Council strikes the words "shall have an energy factor of not less than 78 per cent, except that existing homes may have an energy factor of not less than 62 per cent", and replaces them with "shall have a uniform energy factor of not less than 0.78 or alternatively a thermal efficiency of not less than 90%, except that existing homes may have a uniform energy factor of not less than 0.62".

11. In Book I, Division B, Part 10, Article 10.2.2.15., Council:

(a) in Sentence (1)(a), strikes out "or";

(b) in Sentence (1)(b)(ii), strikes "." and substitutes ", or" to the end of the sentence; and

(c) adds "c) match ignition.".

12. In Book I, Division B, Part 10, Article 10.2.2.17., Council adds the words "except for mechanical ducts cast into concrete structure," at the beginning of Sentence (3)(g).

13. In Book I, Division B, Part 10, Article 10.2.2.20, Council:

a. strikes the title "**EnerGuide Rating System Audit or Passive House Planning Package File (PHPP)**", and replaces it with "**Passive House Planning Package (PHPP), EnerGuide, or Other Energy Documentation**"; and

b. strikes Sentence (1), and replaces it with

"1) In a *building* required to comply with this Article, at the time of building permit application, and at the time of final inspection, the owner shall provide to the Chief Building Official *acceptable* documentation, in the form of

a) a PHPP file from a Certified Passive House Consultant or Designer, or
b) an EnerGuide Rating System Audit, or
c) for *buildings* ineligible for an EnerGuide Rating System Audit, a Hot2000 file modelled in general mode and using the same baseload assumptions as Energuide for New Homes mode, or equivalent energy modelling documentation, *acceptable* to the Chief Building Official.".

14. In Book I, Division B, Part 10, Subsection 10.2.2., Council adds:

"10.2.2.21. **Building and Dwelling Unit Airtightness Testing**

1) In a *building* required to comply with this Article, the *building* and *dwelling units* shall be tested for airtightness in accordance with
a) ASTM E 779, Standard Test Method for Determining Air Leakage Rate by Fan Pressurization,
b) USACE Version 3, Air Leakage Test Protocol for Building Envelopes, or
c) airtightness protocol recognized by Natural Resources Canada for use in homes and buildings labeled under the EnerGuide for New Homes program.

2) A *building* required to comply with this Article shall have maximum tested air leakage rates in conformance with Table 10.2.2.21., or sealed to the satisfaction of the Chief Building Official.

Table 10.2.2.21.
Maximum Tested Air Leakage Rates
Forming part of Sentence 10.2.2.21.(2)

Building Classification	**Maximum Tested Air Leakage Rate**
Buildings, excluding *1 or 2 Family Dwellings* and 1 to 3 *Storey* Residential	2.03 L/s/m² at 75 pascals
Ground-oriented *dwelling units*	3.5 air changes per hour at 50 pascals

"

15. In Book I, Division B, Article 10.5.1.1., Council strikes Table 10.5.1.1., and replaces it with:
"

Table 10.5.1.1.
Objectives and Functional Statements Attributed to the Acceptable Solutions in Part 10
Forming part of Sentence 10.5.1.1.(1)

Acceptable	Functional Statements and Objectives[1]

Solutions	
10.2.2.2. ANSI/ASHRAE/IESNA 90.1	
(1)	[F85, F86-OE1]
10.2.2.3. National Energy Code of Canada for Buildings	
(1)	[F85, F86-OE1]
10.2.2.5. Building Energy and Emissions Performance	
(1)	[F85, F86-OE1]
(2)	[F85, F86-OE1]
10.2.2.6. Building Envelope Opaque Elements	
(1)	[F85-OE1]
(2)	[F85-OE1]
10.2.2.7. Windows, Glass Doors and Skylights	
(1)	[F85-OE1]
10.2.2.8. Building Envelope Vestibules	
(1)	[F85-OE1]
10.2.2.9. Sub-metering in Buildings	
(1)	[F86, OE1]
(2)	[F86, OE1]
10.2.2.10. Lighting Controls in Residential Buildings	
(1)	[F86, OE1]
10.2.2.11. Hot Water Tank Piping	
(1)	[F85-OE1]
(2)	[F85, F86-OE1]
(3)	[F100-OE1]
10.2.2.12. Domestic Gas-Heated Hot Water Heaters	
(1)	[F86-OE1]
10.2.2.13. Domestic Gas-Heated Boilers	
(1)	[F86-OE1]
10.2.2.14. Domestic Gas-Heated Furnaces	
(1)	[F86-OE1]
10.2.2.15. Domestic Gas-Fired Fireplaces	
(1)	[F86-OE1]
	[F41, F44-OS3.4]
	[F44-OH1.1]
10.2.2.16. Domestic Wood Burning Heating Appliances	
(1)	[F86-OE1]
	[F44-OS3.4]
	[F44-OH1.1]
10.2.2.17. Domestic Heat Recovery Ventilators	
(1)	[F85-OE1]

(2)	[F85-OE1]
10.2.2.20. Passive House Planning Package (PHPP), EnerGuide, or Other Energy Documentation	
(1)	[F85-OE1]
10.2.2.21. Building and Dwelling Unit Airtightness Testing	
(1)	[F85-OE1]
(2)	[F85-OE1]
10.3.1.1. Fixture Fitting Maximum Flow Rates	
(1)	[F84-OE2]
10.3.1.2. Fixture Efficiency	
(1)	[F83-OE2]
(2)	[F83-OE2]

Notes to Table 10.5.1.1.:

(1) See Parts 2 and 3 of Division A."

16. In Book I, Appendix A of Division B, Council strikes appendix note A-10.2.2.12.(2).

17. In Book I, Division B, Part 1, Article 1.3.1.2., Table 1.3.1.2.(1) Council strikes:

"

ANSI/ ASHRAE/ IESNA	90.1-2010	Energy Standard for Buildings Except Low-Rise Residential Buildings	10.2.1.1.(1)(a)
CCBFC	NRCC 54435-2011	National Energy Code of Canada for Buildings	10.2.2.3.

"

and substitutes:

"

ANSI/ ASHRAE/ IESNA	90.1-2016	Energy Standard for Buildings Except Low-Rise Residential Buildings	10.2.2.2
CCBFC	NRCC 56191	National Energy Code of Canada for Buildings 2015	10.2.2.3.

".

18. In Book I, Division B, Part 10, Council strikes Article 10.2.2.2. and Article 10.2.2.3., and substitutes:

"10.2.2.2. **ANSI/ASHRAE/IESNA 90.1**

1) A *building* designed in accordance with this Article shall, be designed and constructed in accordance with ANSI/ASHRAE/IESNA 90.1, “Energy Standard for Buildings, except Low-Rise Residential Buildings”, and with

a) a climate zone of 4,
b) ventilation in conformance with ASHRAE 62 (except addendum n),
c) the 5 per cent in Table 11.5.1.5. Building Envelope, Exception a., being replaced by 2 per cent, if designed in accordance with ASHRAE 90.1, Section 11,
d) the 5 per cent in Table G3.1.5.a. Building Envelope, Exception 1., being replaced by 2 per cent, if designed in accordance with ASHRAE 90.1, Appendix G,
e) no requirement to comply with the Fenestration Orientation provisions of ASHRAE 90.1, Article 5.5.4.5.,
f) no requirement to comply with Automatic Receptacle Control, per ASHRAE 90.1, Article 8.4.2.

10.2.2.3. **National Energy Code of Canada for Buildings**

1) A *building* designed in accordance with this Article shall be designed and constructed in accordance with the National Energy Code of Canada for Buildings (NECB), except that the provisions of this By-law shall apply where the NECB refers to the National Building Code of Canada (NBCC), and shall be designed with

a) a climate zone of 4,
b) ventilation in conformance with ASHRAE 62 (except addendum n),
c) window-to-wall and skylight-to-roof area ratios of the reference building identical to area ratios of the proposed building,
d) a vertical glazing Solar Heat Gain Coefficient which does not exceed an assembly maximum of 0.36,
e) a skylight Solar Heat Gain Coefficient for all types, which does not exceed an assembly maximum of 0.40, where the ratio of the aggregate skylight area to roof area is less than or equal to 3.0 per cent.”.

19. In Book I, Division B, Part 6, Sentence 6.2.2.1.(4), Council strikes the words “ of 6 storeys or less in building height and”.

20. In Book I, Division B, Part 10, Council strikes Article 10.2.1.2. through 10.2.1.5., and substitutes:

“10.2.1.2. **Buildings Without Residential or Commercial Components**

1) All *buildings*, except those included in 10.2.1.3 through 10.2.1.6, shall

a) be designed in accordance with ASHRAE 90.1 as per Article 10.2.2.2. or the NECB as per Article 10.2.2.3.,
b) Reserved,
c) Reserved,

d) Reserved,
e) be provided with vestibules for all doors in accordance with Article 10.2.2.8.,
f) be provided with metering equipment in compliance with Article 10.2.2.9,
g) be provided with lighting controls in conformance with Article 10.2.2.10.,
h) Reserved.
i) conform with Article 10.2.2.15. where fire places are provided.

10.2.1.3. **Residential Buildings of 7 Stories or More, and Commercial Buildings (with or without residential components)**

1) All *buildings* containing Group C, D, or E *Major Occupancies*, except those included in 10.2.1.4 through 10.2.1.6., shall

a) be designed in compliance with energy and emissions performance as per Article 10.2.2.5,
b) Reserved,
c) Reserved,
d) Reserved,
e) be provided with vestibules for all doors in accordance with Article 10.2.2.8.,
f) be provided with metering equipment in compliance with Article 10.2.2.9,
g) be provided with lighting controls in conformance with Article 10.2.2.10.,
h) Reserved,
i) conform with Article 10.2.2.15., where domestic gas fireplaces are provided, and
j) provide airtightness testing in accordance with Article 10.2.2.21.

10.2.1.4. **Residential Buildings of 4 to 6 Storeys, and Mixed-Use Residential Buildings of 1 to 6 Storeys**

1) Except for *buildings* included in 10.2.1.5 or 10.2.1.6, a *building* which is less than 7 *storeys* in *building height*, and which is classified as a Group C *major occupancy*, and containing no other *occupancies* (excluding Group D or E *major occupancy* on the first or second *storeys*, or Group F Division 3 (Storage Garage) *occupancy* subsidiary to the Group C major *occupancy*), shall

a) Be designed in compliance with
   i. energy and emissions performance as per Article 10.2.2.5, or
   ii. ASHRAE 90.1 as per Articles 10.2.2.2. or the NECB as per 10.2.2.3., and thermal insulation conforming with 10.2.2.6.,windows and doors conforming with 10.2.2.7., and be provided with heat recovery ventilators conforming with 10.2.2.17.

b) be provided with vestibules for all doors conforming with Article 10.2.2.8.,
c) be provided with metering equipment conforming with Article 10.2.2.9.,
d) be provided with lighting controls conforming with Article 10.2.2.10.,

e) be provided with mechanical equipment conforming with Articles 10.2.2.11. through 10.2.2.14.,
f) , conform with Article 10.2.2.15., where domestic gas fireplaces are provided, and
g) provide airtightness testing in accordance with Article 10.2.2.21.

10.2.1.5. **Residential Buildings of 1 to 3 Storeys (other than 1 or 2 Family Dwellings)**

1) Except as otherwise required in this Subsection, a *building*, other than a *1 or 2 Family Dwelling*, which is less than 4 *storeys* in *building height*, and which is entirely classified as Group C *major occupancy*, excluding Group F Division 3 (Storage Garage) *occupancy* subsidiary to the Group C *major occupancy*, shall

a) be provided with thermal insulation conforming with Article 10.2.2.6.,
b) be provided with windows and doors conforming with Article 10.2.2.7.,
c) be provided with vestibules for all doors conforming with Article 10.2.2.8.,
d) be provided with metering equipment conforming with Article 10.2.2.9.,
e) be provided with lighting controls conforming with Article 10.2.2.10.,
f) where provided, domestic hot water heating shall conforming with Article 10.2.2.11. through 10.2.2.13. as applicable,
g) comply with Article 10.2.2.14. where domestic gas heated furnaces or make-up air units are provided,
h) comply with Article 10.2.2.15. where domestic gas fireplaces are provided,
i) be provided with and Heat recovery ventilators in conformance with Article 10.2.2.17.,
j) be designed with a solar photovoltaic ready pipe run in accordance with Article 10.2.2.19.,
k) provide documentation in accordance with Article 10.2.2.20., and
l) provide airtightness testing in accordance with Article 10.2.2.21.

10.2.1.6. **One and Two Family Dwellings**

1) Except as otherwise required in this Subsection, a *one-family dwelling* and *two-family dwelling*, with or without *secondary suites* or *lock-off units*, and including *laneway houses*, shall

a) be designed with thermal insulation conforming with Article 10.2.2.6.,
b) be designed with windows and doors conforming with Article 10.2.2.7.,
c) be provided with metering equipment conforming with Article 10.2.2.9.,
d) be provided with lighting controls conforming with Article 10.2.2.10.,
e) where provided, domestic hot water heating shall comply with Article 10.2.2.11. through 10.2.2.13. as applicable,
f) where provided, domestic gas heated furnaces or make-up air units shall comply with Article 10.2.2.14.,
g) where provided, domestic fireplaces shall comply with Article 10.2.2.15. and 10.2.2.16. as applicable,
h) except for laneway houses, conform with Article 10.2.2.17.,

i) be designed with a solar ready pipe run in accordance with Article 10.2.2.18., and
j) provide documentation in accordance with Article 10.2.2.20.
k) provide airtightness testing in accordance with Article 10.2.2.21.”.”

21. In Book I, Division B, Part 10, Council strikes Article 10.2.2.5 and substitutes:

“10.2.2.5. **Building Energy and Emissions Performance**

1) For a *building* required to conform with this Article, energy modelling shall conform to:
   a. the applicable requirements of ASHRAE 90.1 ECB, or Part 8 of the NECB, and
   b. the City of Vancouver Energy Modelling Guidelines.

2) Except as permitted in Sentence (3), a *building* designed with this Article shall demonstrate the performance values of the proposed *building* comply with the limits in Table 10.2.2.5.A.
3) Compliance with the GHGI limits in Table 10.2.2.5.A is not required where a *building* can demonstrate the performance values of the proposed *building* comply with the TEUI and TEDI limits in Table 10.2.2.5.B.

Table 10.2.2.5.A
Maximum Energy Use and Emissions Intensities
Forming part of Sentence 10.2.2.5.(2)

Occupancy Classification (1)	**Total Energy Use Intensity (kWh/m^2a)**	**Thermal Energy Demand Intensity (kWh/m^2a)**	**Greenhouse Gas Intensity ($kgCO_{2e}/m^2a$)**
Group C *occupancies* in *buildings* up to 6 *Storeys*	110	25	5.5
Group C *occupancies* in *buildings* over 6 *Storeys*, except Hotel and Motel	130	45	14
Hotel and Motel *occupancies*	170	30	14
Group D and E *occupancies*, except Office	170	30	5
Office *occupancies*	130	30	7
All other *occupancies*	Comply with ASHRAE 90.1 ECB in accordance with Article 10.2.2.2, or NECB Part 8 in accordance with the Article 10.2.2.3		

Notes to Table 10.2.2.5.A.:

(1) For buildings containing multiple *occupancies*, refer to the procedures on mixed-use buildings in Section 5 of the City of Vancouver Energy Modelling Guidelines.

Table 10.2.2.5.B
Maximum Energy Use and Emissions Intensities
Forming part of Sentence 10.2.2.5.(3)

Occupancy Classification	Total Energy Use Intensity (kWh/m^2a)	Thermal Energy Demand Intensity (kWh/m^2a)	Greenhouse Gas Intensity ($kgCO_{2e}/m^2a$)
Group C *occupancies* in *buildings* over 6 *Storeys*, except Hotel and Motel	120	30	6
Hotel and Motel *occupancies*	140	20	8
Group D and E *occupancies*, except Office	120	20	3
Office *occupancies*	100	20	3

".

22. In Book I, Division B, Part 10, Table 10.2.2.6, Council strikes from the title the text "**Containing No Other *Major Occupancies***".

23. In Book I, Division B, Part 10, Table 10.2.2.7, Council adds to the end of the Table:
"

Storefront curtainwall, window, and door assemblies	2.27

".

24. In Book I, Division B, Part 10, Table 10.2.2.21, Council adds to the end of the Table:
"

Suites in *multi-family* buildings	1.23 L/s/m² at 50 pascals

".

25. In Book I, Division A, Sentence 1.4.1.2.(1) Defined Terms, Council adds the following in correct alphabetical order:

"*Low Carbon Energy System* means a professionally operated and maintained district-scale or on-site system that supplies heat energy, primarily derived from highly-efficient and renewable sources, in order to provide space heating and conditioned ventilation air for buildings, and may also provide domestic hot water and cooling service.".

26. In Book I, Division B, Part 10, Council strikes Article 10.2.2.5 and substitutes:

“10.2.2.5. **Building Energy and Emissions Performance**

1) For a *building* required to conform with this Article, energy modelling shall conform to:
   a. the applicable requirements of ASHRAE 90.1 ECB, or Part 8 of the NECB, and
   b. the City of Vancouver Energy Modelling Guidelines.

2) Except as permitted in Sentences (3)or (4), a *building* designed with this Article shall demonstrate the performance values of the proposed building comply with the limits in Table 10.2.2.5.A.
3) Compliance with the GHGI limits in Table 10.2.2.5.A is not required where a *building* can demonstrate the performance values of the proposed *building* comply with the TEUI and TEDI limits in Table 10.2.2.5.B.
4) Compliance with the TEUI and TEDI limits in Table 10.2.2.5.A is not required where a *building* is connected to a *Low Carbon Energy System*, and can demonstrate the performance values of the proposed *building* comply with the limits in Table 10.2.2.5.C.

Table 10.2.2.5.A
Maximum Energy Use and Emissions Intensities
Forming part of Sentence 10.2.2.5.(2)

***Occupancy* Classification** (1)	**Total Energy Use Intensity (kWh/m^2a)**	**Thermal Energy Demand Intensity (kWh/m^2a)**	**Greenhouse Gas Intensity ($kgCO_{2e}/m^2a$)**
Group C *occupancies* in *buildings* up to 6 *Storeys*, except Hotel and Motel	110	25	5.5
Group C *occupancies* in *buildings* over 6 *Storeys*, except Hotel and Motel	120	30	6
Hotel and Motel *occupancies*	140	20	8
Group D and E *occupancies*, except Office	120	20	3
Office *occupancies*	100	20	3
All other *occupancies*	Comply with ASHRAE 90.1 ECB in accordance with Article 10.2.2.2, or NECB Part 8 in accordance with the Article 10.2.2.3		

Notes to Table 10.2.2.5.A.:

(1) For buildings containing multiple *occupancies*, refer to the procedures on mixed-use buildings in Section 5 of the CoV Energy Modelling Guidelines.

Table 10.2.2.5.B **Maximum Energy Use and Emissions Intensities** Forming part of Sentence 10.2.2.5.(3)			
***Occupancy* Classification**	**Total Energy Use Intensity (kWh/m^2a)**	**Thermal Energy Demand Intensity (kWh/m^2a)**	**Greenhouse Gas Intensity ($kgCO_{2e}/m^2a$)**
Group C *occupancies*	100	15	N/A

Table 10.2.2.5.C **Maximum Energy Use and Emissions Intensities** **For Buildings Connected to a *Low Carbon Energy System*** Forming part of Sentence 10.2.2.5.(4)			
***Occupancy* Classification**	**Total Energy Use Intensity (kWh/m^2a)**	**Thermal Energy Demand Intensity (kWh/m^2a)**	**Greenhouse Gas Intensity ($kgCO_{2e}/m^2a$)**
Group C *occupancies* in *buildings* up to 6 *Storeys*, except Hotel and Motel	110	25	5.5
Group C *occupancies* in *buildings* over 6 *Storeys*, except Hotel and Motel	130	40	6
Hotel and Motel *occupancies*	170	30	8
Office *occupancies*	170	30	3
Business and Personal Services or Mercantile *Occupancies*, except Office	170	30	3

".

27. A decision by a court that any part of this By-law is illegal, void, or unenforceable severs that part from this By-law, and is not to affect the balance of this By-law.

28. This By-law is to come into force and take effect as follows:

a) sections 2 through 16 come into force and take effect upon enactment;
b) sections 17 and 18 come into force and effect on January 1, 2019;
c) sections 19 through 24 come into force and effect on June 3, 2019; and
d) sections 25 and 26 come into force and effect on June 1, 2021.

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EXPLANATION

Building By-law amending By-law
Re: Energy Efficiency

The attached By-law will implement Council's resolution of XXX, 2018 to amend the Building By-law regarding energy efficiency measures, effective , 201 .

Director of Legal Services
[date]

Draft By-law to amend Building By-law No. 10908
Regarding water efficiency

Note: A by-law will be prepared generally in accordance with the provisions listed below.

29. This by-law amends the indicated provisions of Building By-law 10908.

30. In Book I, Division A, Part 1, in Article 1.4.1.2., Council adds the following definitions in alphabetical order:

"***Emergency once through cooling equipment*** means ***once through cooling equipment*** that is not normally operated and is only activated in the event of a sudden, unforeseen failure of an otherwise properly designed, operated and maintained primary cooling system.

Maintenance once through cooling equipment means ***once through cooling equipment*** that is not normally operated and is only activated to temporarily supplement or replace the primary cooling system during scheduled maintenance on the primary cooling system.

Non-recirculating liquid ring pump means a vacuum pump that uses water to cool the pump or to create a seal and recirculates less than 60% of the water that passes through the pump.

Once through cooling equipment means equipment that produces a cooling effect by transfer of heat to water that is only circulated once through the equipment and is then discharged, and includes but is not limited to commercial and industrial air conditioners, refrigerators, freezers, coolers and ice machines.

Self-closing plumbing fixture means a ***plumbing fixture*** that closes automatically upon the deactivation of a mechanical or electronic control mechanism."

31. In Book I, Division B, Part 10, Council strikes out Article 10.3.1.2. and substitutes:

"**10.3.1.2. Plumbing Fixture Fitting Maximum Flow Rates**

1) The flow rates of fittings that supply water to ***plumbing fixtures*** must not exceed the maximum flow rate at the test pressures listed for that fitting in Table 10.3.1.2.

Table 10.3.1.2. Maximum Flow Rate Forming part of Sentence 10.3.1.2.(1)		
Fitting	Maximum Flow Rate (L/min)	Test Pressure (kPa)
Lavatory Faucet (for ***private use***)	5.7	415
Lavatory Faucet (for ***public use***)	1.9(1)(2)	415
Kitchen Faucet (non-residential)	8.3	415
Kitchen Faucet (residential)	6.8(3)	415
Shower Head	7.6(4)(5)	550
Pre-Rinse Spray Valve	4.8(6)	415
Wash Fountain, per ***plumbing fixture*** fitting	6.8(7)	415

Notes to Table 10.3.1.2.:

(1) Must be a ***self-closing plumbing fixture***. A ***metering fixture*** faucet is limited to 1.0 L per cycle.

(2) A lavatory faucet in a health care facility is permitted a maximum flow rate of 8.3 L/min (at 415 kPa test pressure). The ***Chief Building Official*** may, for human health reasons, permit exemptions within other facilities, to a maximum flow rate of 8.3 L/min (at 415 kPa test pressure).

(3) May be temporarily increased to a maximum flow rate of 8.3 L/min (at 415 kPa test pressure) but must default to the lower flow rate upon release of the activation mechanism or closure of the faucet valve.

(4) Emergency and safety ***shower heads*** and ***shower heads*** in health care facilities and correctional facilities are exempted from this requirement.

(5) Where multiple ***shower heads*** installed for ***public use*** are served by one temperature control, each ***shower head*** shall be a ***self-closing plumbing fixture*****,** except that emergency and safety ***shower heads*** and ***shower heads*** in health care facilities and correctional facilities are exempted from this requirement.

(6) Each ***pre-rinse spray valve*** must be equipped with an automatic shut-off.

(7) A maximum flow rate of 6.8 L/min is permitted for each 508 mm of rim space. Must be a ***self-closing plumbing fixture***. For a wash fountain with ***metering fixture*** faucets, a maximum of one ***metering fixture*** faucet is permitted for each 508 mm of rim space. A ***metering fixture*** faucet is limited to 1.0 L per cycle."

32. In Book I, Division B, Part 10, Council strikes out Article 10.3.1.3., and substitutes:

"**10.3.1.3. Plumbing Fixture Efficiency**

1) The flush cycle for the installation of a water closet or urinal must not exceed the flush cycle listed for that ***plumbing fixture*** in Table 10.3.1.3.A

Table 10.3.1.3.A Maximum Flush Cycle Forming part of Sentence 10.3.1.3.(1)	
Plumbing Fixture	Maximum Flush Cycle (L)
Water Closet (Tank Type)	4.8(1)(2)
Water Closet (Direct Flush)	4.8(1)
Urinal (Tank Type)	1.9(3)
Urinal (Direct Flush)	1.9

Notes to Table 10.3.1.3.A:

(1) A maximum flush cycle of 6.0 L may be permitted where, in the opinion of the ***Chief Building Official***, the existing ***plumbing system*** cannot accommodate and cannot be updated to accommodate the required flush cycle.
(2) A water closet with a dual flush cycle of 4.1 L or less and 6.0 L complies with this requirement.
(3) The water supply to flush tanks equipped for automatic flushing shall be controlled with a timing device that limits operation to the period during which the building is normally occupied.

2) Appliances listed in Table 10.3.1.3.B shall comply with the applicable Energy Star program requirements or be of ***acceptable equivalency***.

Table 10.3.1.3.B Appliance Energy Star Program Requirements Forming part of Sentence 10.3.1.3.(2)	
Appliance	Energy Star Program Requirements
Residential clothes washer(1)	Product Specification for Clothes Washers
Commercial clothes washer(1)	Product Specification for Clothes Washers
Residential dishwasher(2)	Product Specification for Residential Dishwashers
Commercial dishwasher(3)	Product Specification for Commercial Dishwashers
Commercial ice maker(4)	Product Specification for Automatic Commercial Ice Makers
Commercial steam cooker(5)	Product Specification for Commercial Steam Cookers
Combination oven(6)	Product Specification for Commercial Ovens

Notes to Table 10.3.1.3.B:

(1) "Residential clothes washer" and "commercial clothes washer" are as defined by the Energy Star Program Requirements Product Specification for Clothes Washers.
(2) "Residential dishwasher" is as per the definition of "dishwasher" by the Energy Star Program Requirements Product Specification for Residential Dishwashers.
(3) "Commercial dishwasher" is as per the definition of "dishwashing machine" by the Energy Star Program Requirements Product Specification for Commercial Dishwashers. Dishwashers intended for laboratory applications are exempted.
(4) "Commercial ice maker" is as per the definition of "automatic commercial ice maker" by the Energy Star Program Requirements Product Specification for Automatic Commercial Ice Makers.
(5) "Commercial steam cooker" is as per the definition of "commercial steam cooker" by the Energy Star Program Requirements Product Specification for Commercial Steam Cookers.
(6) "Combination oven" is as per the definition of "combination oven" by the Energy Star Program Requirements Product Specification for Commercial Ovens.

3) Clothes washers with a top-loading design that are designed for use in applications in which the occupants of more than one household will be using the clothes washer, such as multi-family housing common areas and coin laundries, shall not be installed."

33. In Book I, Division B, Part 10, Council adds a new Article 10.3.1.7. as follows:

"10.3.1.7. Non-recirculating Applications

1) The city's water system shall not be connected to

a) ***once through cooling equipment***, except where ***emergency once through cooling equipment*** or ***maintenance once through cooling equipment*** is operated with permission or authorization in writing from the ***City Engineer***,
b) venturi-type flow-through vacuum generators or aspirators in which running water is used solely for the venturi effect,
c) ***non-recirculating liquid ring pumps***, or
d) non-recirculating wet-hood scrubbers.

2) No systems or equipment shall be installed that allow for the use of treated drinking water supplied directly or indirectly by the city to temper or dilute steam condensate and other discharges to the sanitary or storm system."

34. In Book II, Division A, Part 1, in Article 1.4.1.2., Council adds the following definition in alphabetical order:

"*Self-closing plumbing fixture* means a ***plumbing fixture*** that closes automatically upon the deactivation of a mechanical or electronic control mechanism."

35. In Book II, Division A, Part 1, in Article 2.2.2.8., Council strikes 2.2.2.8.(1) and substitutes:

"

1) Every lavatory faucet installed for ***public use*** shall be a ***self-closing plumbing fixture."***

36. A decision by a court that any part of this By-law is illegal, void, or unenforceable severs that part from this By-law, and is not to affect the balance of this By-law.

37. This By-law is to come into force and take effect on January 1, 2019.

*****

EXPLANATION

Building By-law amending By-law
Re: Sustainability and water conservation

The attached By-law will implement Council's resolution of XXX, 2018 to amend the Building By-law regarding water conservation measures, effective January 1, 2019.

Director of Legal Services
[date]

GREEN BUILDINGS POLICY FOR REZONINGS

Authority - Director of Planning
Effective July 22, 2010
Amended June 25, 2014, June 8, 2015, January 14, 2016, November 29, 2016, February 7, 2017, and May 2, 2018

All rezonings must meet the following requirements of either:

A. Near Zero Emissions Buildings, or
B. Low Emissions Green Buildings.

This policy is effective immediately, and shall be mandatory for all Rezoning Applications received on or after ~~May 1, 2017~~ May 2, 2018, with exceptions permitted at the discretion of the Director of Planning. For rezoning Applications received prior to ~~May 1, 2017~~ May 2, 2018 that have not yet been approved by Council, applicants may choose to meet this updated version of the Policy or the preceding version.

REQUIREMENTS

A. Near Zero Emissions Buildings

(1) Near Zero Emissions Building Standard

Projects shall be designed to meet Passive House requirements and apply for certification, or to an alternate near zero emissions building standard, such as the International Living ~~Building~~ Future Institute's ~~Net~~ Zero Energy Building Certification, as deemed suitable by the Director of Sustainability.

AND

(2) Energy System Sub-Metering and Reporting

Projects shall meet the requirements for Energy System Sub-Metering and Reporting, as described in B.5 of this policy.

AND

(3) Low-Emitting Materials

Projects shall be designed to minimize emissions from interior materials containing volatile organic compounds (VOCs) or added urea formaldehyde, as described in B.8 of this policy.

OR

B. Low Emissions Green Buildings

(1) LEED Gold - Building Design and Construction

All projects – with the exception of residential buildings - shall register with the Canadian Green Building Council (CaGBC) and be designed to achieve LEED Gold certification for Building Design + Construction (BD+C), or an alternate holistic green building rating system. A residential building is defined as a building in which at least 50% of the gross floor area is residential space. Where a project has multiple buildings, each building shall be evaluated separately.

The BD+C project type applies to buildings that are being newly constructed or going through a major renovation, and includes many rating systems designed for various building types. The applicant is responsible for choosing the rating system (within BD+C) that is most applicable to the project.

AND

(2) Performance Limits

All buildings shall meet or exceed performance limits according to their building type summarized in the tables below, as modelled according to the City of Vancouver Energy Modelling Guidelines. The Energy Modelling Guidelines set standard assumptions and requirements for energy models when assessing compliance with the limits, including accounting for thermal bridging, consideration of summertime thermal comfort, and the treatment of mixed-use buildings.

Performance Limits Buildings Not Connected to a City-recognized Low Carbon Energy System			
Building Type	TEUI (kWh/m^2)	TEDI (kWh/m^2)	GHGI ($kgCO_2/m^2$)
Residential Low-Rise (< 7 storeys)	100	15	5
Residential High-Rise (7+ storeys)	120	~~32~~ 30	6
Office	100	27	3
Retail	170	21	3
Hotel	170	25	8
All Other Buildings	EUI 35% ~~below 90.1-2010~~ better than Building By-law energy efficiency requirements, Section 10.2, in effect at the time of rezoning application		

Performance Limits Buildings Connected to a City-recognized Low Carbon Energy System			
Building Type	TEUI (kWh/m^2)	TEDI (kWh/m^2)	GHGI ($kgCO_2/m^2$)
Residential Low-Rise (< 7 storeys)	110	25	5
Residential High-Rise (7+ storeys)	130	40	6
Office	110	27	3
Retail	170	21	3
Hotel	~~210~~ 170	25	8
All Other Buildings	EUI 35% ~~below 90.1-2010~~ better than Building By-law energy efficiency requirements, Section 10.2, in effect at the time of rezoning application		

TEUI: Total Energy Use Intensity
TEDI: Thermal Energy Demand Intensity
GHGI: Greenhouse Gas Intensity

Alternate Compliance Pathway for Energy and GHG Reductions: In lieu of compliance with the GHGI limits required by the table above, Residential High-Rises (7+ storeys) and Hotels may achieve a TEUI of 100 and 120 respectively, and a TEDI of 15. In addition, any building type seeking an alternative compliance path may use A.1, Near Zero Emissions Building Standard.

Small Buildings: for Part 9 buildings, in lieu of the TEUI and TEDI limits required by this policy, projects may meet an alternate set of performance or prescriptive requirements, such as an equivalent step of the Part 9 BC Energy Step Code, as deemed acceptable by the Director of Sustainability.

AND

(3) Airtightness Testing

Whole-building airtightness for each building is to be tested and reported, and all buildings are to be designed and constructed with the intention of meeting an air-leakage target of 2.0 L/s*m² @75 Pa (0.40 cfm/ft² @ 0.3"w.c.), or sealed according to good engineering practice.

Airtightness of suites is to be tested and reported for residential buildings and must demonstrate compliance with a suite-level air-leakage target of 1.2 L/s*m² @50 Pa (0.23 cfm/ft² @ 0.2"w.c.), as tested to ASTM E779 or an equivalent standard.

AND

(4) Enhanced Commissioning

An enhanced commissioning process for all building energy systems is to be completed in accordance with, CSA Z5000-18, or ASHRAE Guideline 0-2005 and 1.1-2007, or an alternate commissioning standard acceptable by the Director of Sustainability.

AND

(5) Energy System Sub-Metering and Reporting

Separate master metering for each energy utility (e.g. Electricity, Gas, etc.) and each building is to be provided as well as sub-metering of all major energy end-uses and major space uses within each building.

An Energy Star Portfolio Manager account is to be setup for each building and must include all basic property information for each building as designed, including setup of meters for all energy utilities servicing the building.

A rezoning applicant will enter into an agreement with the City, on terms and conditions acceptable to the City, that requires the future owner of the building to report energy use data, on an aggregated basis, for the building as a whole and certain common areas and building systems. Such an agreement will further provide for the hiring of an approved professional service provider to assist the building owner for a minimum of three years in collecting and submitting energy use data to the City.

AND

(6) Refrigerant Emissions and Embodied Emissions

All projects shall calculate and report the life-cycle equivalent annual carbon dioxide emissions of each building, in $kgCO2e/m^2$, from the emission of refrigerants. This requirement does not apply to projects where the total installed heating and cooling capacity of equipment containing refrigerants is less than 35kW.

All projects shall report the life-cycle equivalent carbon dioxide emissions (i.e. global warming potential impact, or 'embodied carbon') of each building, in $kgCO2e/m^2$, as calculated by a whole-building life-cycle assessment (LCA).

AND

(7) Verified Direct Ventilation

All buildings shall be designed and constructed with a ventilation system that provides outdoor air directly to all occupiable spaces, in the quantities defined by code. This includes bedrooms, living rooms, and dens in residential units. The ventilation system shall allow for the designed flow rates to be tested and verified at the occupiable space level as part of the enhanced commissioning process.

AND

(8) Low-Emitting Materials

Emissions from interior materials containing volatile organic compounds (VOCs) or added urea formaldehyde are to be minimized by meeting the content requirements of Green Seal, Green Label, Green Label Plus, FloorScore, South Coast Air Quality Management District (SCAQMD) Rules, or alternate low VOC criteria as applicable to each material or product, and shall contain no added urea formaldehyde resins.

AND

(9) Indoor Air Quality Testing

Indoor air quality testing is to be conducted for formaldehyde, particulates, ozone, total volatile organic compounds, and carbon monoxide prior to occupancy, and report results to the City as compared to acceptable target concentration levels and standards.

AND

(10) Integrated Rainwater Management and Green Infrastructure

Explore and describe measures for the management of the site's rainfall through integrated rainwater management and Green Infrastructure (GI) as described in the City-Wide Integrated Rainwater Management Plan. Project teams can refer to the Citywide Integrated Rainwater Management Plan Volume I: Vision, Principles and Actions and Volume II: Best Management Practice Toolkit, for specific targets and examples of green infrastructure for rainwater management.

AND

(11) Resilient Drinking Water Access

A water fountain, bottle-filling station, or other fixture capable of operating on city water pressure alone and without electricity is to be provided in a location easily accessible to all building occupants.

REQUIREMENT ADMINISTRATION

Projects demonstrating that the building is extremely ill-suited to achieving a specific requirement may request that the requirement be modified, or deemed not applicable, at the discretion of the Director of Sustainability.

HERITAGE BUILDINGS

Where a project includes heritage retention, heritage components can be exempted from one or all of the requirements of this policy at the discretion of the Director of Planning.

BCBC (Gas)							
			Code (gas)	gas	elec	total	
Base Cost ($/ft²)	250		EUI - Note 1	102	67.5	170	
Base Monthly Mortgage	$ 2,415.24		ECI - Note 3	3.2	7.0	10.1	
			GHGI	18.9	0.7	19.7	

STEP 2 (Gas)							
Incremental Cost (%)	0.4%		Step 2 (gas)	gas	elec	total	savings from Gas Code
Incremental Cost ($/ft²)	1.0		EUI	63.6	64.8	128	24%
Incremental Cost ($/m²)	10.8		ECI	2.0	6.7	8.6	15%
Energy Savings ($/m²)	1.5		GHGI	11.8	0.7	12.5	37%
Simple Payback (yrs)	7						
Incremental Cost in 800ft² suite	$ 861						
Monthly Mortgage Cost - Note 2	$ 2,419.40						
Incremental Monthly Mortgage	$ 4.16						
Energy Savings in 800ft² suite	$ 118						
Monthly Energy Savings	$ 10						
TOTAL Monthly Savings	$ 6						

STEP 3 (Gas)							
Incremental Cost (%)	0.8%		Step 3 (gas)	gas	elec	total	savings from Gas Code
Incremental Cost ($/ft²)	2.0		EUI	51.5	65.2	117	31%
Incremental Cost ($/m²)	21.5		ECI	1.6	6.7	8.3	18%
Energy Savings ($/m²)	1.8		GHGI	9.5	0.7	10.2	48%
Simple Payback (yrs)	12						
Incremental Cost in 800ft² suite	$ 1,722						
Monthly Mortgage Cost	$ 2,423.56						
Incremental Monthly Mortgage	$ 8.32						
Energy Savings in 800ft² suite	$ 145						
Monthly Energy Savings	$ 12						
TOTAL Monthly Savings	$ 4						

BCBC (Electric)							
			Code (elec)	gas	elec	total	
Base Cost ($/ft²)	250		EUI	45.7	93	138.7	
Base Monthly Mortgage	$ 2,415.24		ECI	1.4	9.6	11.0	
			GHGI	8.5	1.0	9.5	

STEP 2 (Electric)							
Incremental Cost (%)	0.4%		Step 2 (elec)	gas	elec	total	savings from Elec Code
Incremental Cost ($/ft²)	1.0		EUI	31.4	83.3	114.7	17%
Incremental Cost ($/m²)	10.8		ECI	1.0	8.6	9.6	13%
Energy Savings ($/m²)	1.4		GHGI	5.8	0.9	6.7	29%
Simple Payback (yrs)	7						
Incremental Cost in 800ft² suite	$ 861						
Monthly Mortgage Cost	$ 2,419.40						
Incremental Monthly Mortgage	$ 4.16						
Energy Savings in 800ft² suite	$ 115						
Monthly Energy Savings	$ 10						
TOTAL Monthly Savings	$ 5						

STEP 3 (Electric)							
Incremental Cost (%)	0.8%		Step 3 (elec)	gas	elec	total	savings from Elec Code
Incremental Cost ($/ft²)	2.0		EUI	31.4	72.4	103.8	25%
Incremental Cost ($/m²)	21.5		ECI	1.0	7.5	8.4	23%
Energy Savings ($/m²)	2.6		GHGI	5.8	0.8	6.6	30%
Simple Payback (yrs)	8						
Incremental Cost in 800ft² suite	$ 1,722						
Monthly Mortgage Cost	$ 2,423.56						
Incremental Monthly Mortgage	$ 8.32						
Energy Savings in 800ft² suite	$ 205						
Monthly Energy Savings	$ 17						
TOTAL Monthly Savings	$ 9						

STEP 3 (Electric, compared to BCBC gas)							
Incremental Cost (%)	0.8%		Step 3 (elec)	gas	elec	total	savings from Gas Code
Incremental Cost ($/ft²)	2.0		EUI	31.4	72.4	103.8	39%
Incremental Cost ($/m²)	21.5		ECI	1.0	7.5	8.4	17%
Energy Savings ($/m²)	1.7		GHGI	5.8	0.8	6.6	66%
Simple Payback (yrs)	13						
Incremental Cost in 800ft² suite	$ 1,722						
Monthly Mortgage Cost	$ 2,423.56						
Incremental Monthly Mortgage	$ 8.32						
Energy Savings in 800ft² suite	$ 135						
Monthly Energy Savings	$ 11						
TOTAL Monthly Savings	$ 3						

NOTES:

1) EUIs and costs based on models from the BC Housing Metrics Study
2) All mortgage costs are via VanCity Online Mortgage Calculator
   $500,000 baseline mortgage
   25yr mortgage
   Monthly payments
   3.190% - 5yr Closed Mortgage
   https://www.vancity.com/Mortgages/MortgageCalculators/
3) Utility rates are 3.1¢/kWh for gas, 10.3¢/kWh for electricity
4) Comparisons repeated using more conservative UBC Study and 2016 ZEBP models, with similar results; in Step 3 compared to gas, lower energy cost savings (2-4%), and break-even ($0) monthly savings, but higher GHG savings (68-72%).

Appliance Efficiency Requirements: Economic and Environmental Data

This table summarizes the water, energy and operating cost savings for an Energy Star appliance compared to a non-certified model. The simple payback period for the Energy Star appliance is also provided for any purchase price differential.

Appliance	Sector	Hot water heating	Subset	Simple payback (years)	Net savings (over product life of one appliance)	Lifetime savings (for one appliance)		
						Water (L)	Energy (GJ)	Energy (kWh)
Dishwasher	Residential	Electric	Standard	Immediate	$46	13,429	—	407
			Compact	Immediate	$19	3,581	—	209
		Natural Gas	Standard	Immediate	$80	13,429	1.1	179
			Compact	Immediate	$47	3,581	0.6	92
	Commercial (low temperature)	Electric	Under counter	0.7	$2,168	559,578	—	25,395
			Door type	0.3	$18,829	5,338,791	—	242,288
			Single tank conveyor	Immediate	$18,607	5,747,767	—	272,529
			Multi tank conveyor	0.4	$25,067	8,290,048	—	376,224
		Natural Gas	Under counter	1.2	$1,063	559,578	112.0	—
			Door type	0.5	$9,861	5,338,791	1,068.5	—
			Single tank conveyor	Immediate	$10,301	5,747,767	1,150.3	11,680
			Multi tank conveyor	0.7	$13,087	8,290,048	1,659.1	—
	Commercial (high temperature)	Electric	Under counter	5.7	$353	238,339	—	31,707
			Door type	0.7	$11,485	2,321,213	—	177,949
			Single tank conveyor	1.9	$8,548	1,879,078	—	184,231
			Multi tank conveyor	0.3	$32,082	7,129,441	—	548,152
			Pot, pan and utensil	4.1	$1,064	464,243	—	33,108
		Natural Gas	Under counter	—	($386)	238,339	75.0	14,710
			Door type	1.3	$5,358	2,321,213	730.0	12,410
			Single tank conveyor	3.2	$4,281	1,879,078	591.0	50,224
			Multi tank conveyor	0.6	$15,893	7,129,441	2,242.2	39,712
			Pot, pan and utensil	—	($377)	464,243	146.0	—

Appliance	Sector	Hot water heating	Subset	Simple payback (years)	Net savings (over product life of one appliance)	Lifetime savings (for one appliance)		
						Water (L)	Energy (GJ)	Energy (kWh)
Clothes washer	Residential	Electric	Front loading	2.6	$90	88,512	—	348
			Top loading	3.4	$213	241,934	—	1,250
		Natural Gas	Front loading	2.8	$78	88,512	1.3	70
			Top loading	3.8	$169	241,934	4.8	250
	Commercial (multifamily)	Electric	Front loading	1.6	$695	260,647	—	7,226
		Natural Gas	Front loading	2.5	$372	260,647	28.2	1,003
	Commercial (laundromat)	Electric	Front loading	1.0	$1,200	459,964	—	12,753
		Natural Gas	Front loading	1.5	$744	459,964	49.7	1,770
Ice machine	Commercial (batch)	—	Ice making head	Immediate	$1,029	188,599	—	9,975
			Remote condensing unit	Immediate	$1,005	200,205	—	9,445
			Self-contained unit	Immediate	$449	149,387	—	3,075
	Commercial (continuous)	—	Ice making head	1.1	$907	—	—	14,892
			Remote condensing unit	0.9	$1,138	—	—	17,936
			Self-contained unit	5.3	$17	—	—	3,154
Steam cooker	Commercial (3 pan)	Electric	—	5.9	$909	615,707	—	58,174
		Natural Gas	—	4.9	$1,239	615,707	602.8	—
	Commercial (4 pan)	Electric	—	5.2	$1,511	514,735	—	70,180
		Natural Gas	—	5.4	$902	514,735	556.5	—
	Commercial (5 pan)	Electric	—	4.6	$2,207	444,037	—	83,105
		Natural Gas	—	6.0	$598	444,037	509.1	—
	Commercial (6 pan)	Electric	—	4.1	$2,874	386,790	—	95,285
		Natural Gas	—	6.7	$289	386,790	456.9	—
Combination oven	Commercial	Electric	—	Immediate	$4,640	No data	—	76,415
		Natural Gas	—	Immediate	$1,926	No data	425.0	—

Data Source and Assumptions: These data are from the Natural Resources Canada spreadsheet “Canada’s Energy Star® Simple Savings Calculator.” Data are for a single unit of the applicable appliance. Default calculator values for British Columbia were applied. Version 12.2 was used for all appliances with the exception of ice machines, for which calculator version 11.3 was used.

Attachment 56.1

sustainability

MDPI

Article

Life Cycle Greenhouse Gas Analysis of Multiple Vehicle Fuel Pathways in China

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Abstract: The Tsinghua University Life Cycle Analysis Model (TLCAM) is applied to calculate the life cycle fossil energy consumption and greenhouse gas (GHG) emissions for more than 20 vehicle fuel pathways in China. In addition to conventional gasoline and diesel, these include coal- and gas-based vehicle fuels, and electric vehicle (EV) pathways. The results indicate the following. (1) China's current dependence on coal and relative low-efficiency processes limits the potential for most alternative fuel pathways to decrease energy consumption and emissions; (2) Future low-carbon electricity pathways offer more obvious advantages, with coal-based pathways needing to adopt carbon dioxide capture and storage technology to compete; (3) A well-to-wheels analysis of the fossil energy consumption of vehicles fueled by compressed natural gas and liquefied natural gas (LNG) showed that they are comparable to conventional gasoline vehicles. However, importing rather than domestically producing LNG for vehicle use can decrease domestic GHG emissions by 35% and 31% compared with those of conventional gasoline and diesel vehicles, respectively; (4) The manufacturing and recovery of battery and vehicle in the EV analysis has significant impact on the overall ability of EVs to decrease fossil energy consumption and GHG emissions from ICEVs.

Keywords: life cycle analysis; carbon footprint; vehicle fuel; energy consumption; greenhouse gas

1. Introduction

1.1. Development of Alternative Vehicle Fuels in China

Over the past decade, China's vehicle population has experienced rapid increasing. As of 2015, there were more than 172 million vehicles in China, a figure that has been growing at an average annual rate of 24.5% [1], which is certain to further drive China's growing demand for vehicle fuels. Meanwhile oil supply security, CO_2 and other air pollution from fossil fuel consumption have aroused widespread concern. Together, these have contributed to the increased attention focused on alternative fuels to replace conventional gasoline and diesel.

Currently available alternative combustion fuels include natural gas (NG) (such as compressed NG (CNG) and liquefied NG (LNG)), methanol, ethanol, biodiesel, and coal-to-liquid (CtL) derived fuels. Moreover, the development of electric vehicles (EVs) has also impacted the demand for conventional gasoline and diesel [2,3]. However, recent statistics show that, across all vehicle types, developments in alternative fuels have had a limited impact on the overall market. Approximately 29 million tons of conventional gasoline and diesel were replaced by alternative vehicle fuel in 2015, accounting for 10% of the total amount of gasoline and diesel consumed in that year (the figures for gasoline alone were 16.5 million tons and 14%, respectively) [2–4]. LNG, CTL, and biodiesel are alternatives to conventional diesel fuel, approximately 12.5 million tons of which was replaced by them in 2015, 7% of total diesel consumption in that year [2]. NG is the dominant replacement fuel and was responsible for 73% and 66% of the substitution of conventional gasoline and diesel fuels, respectively [4,5].

1.2. Life Cycle Studies of Vehicle Fuels

Life cycle analysis (LCA) of energy use and greenhouse gas (GHG) emissions has been an important aspect in a comprehensive evaluation of vehicle fuel pathways and has been studied by domestic and foreign scholars who have established specific models for different regions. The Greenhouse gas, Regulated Emissions and Energy use in Transportation (GREET) [6,7] and the Lifecycle Emissions Model (LEM) [8,9] are two of the famous LCA models that have been applied to analyze technical pathways in North America [10–12], Europe [13,14] and other regions [15–17]. The conclusions from such analyses reveal strong regional differences, suggesting that the basic model cannot be simply applied to other areas of the world.

Several publications have focused on LCA in the Chinese context for individual alternative vehicle fuels in recent years [18–27]. In addition, recently published are several comparative analyses between two or more pathways [28–33]. However, owing to a lack of detailed data for many intrinsic operations in the model, many of the conclusions have necessarily been drawn following the extrapolation of experimental data or uncertain future forecasts. Generally, comparative studies between individual pathways are relatively simple with limited analysis of the impact of decision-making in the models. Therefore, the current literature makes it difficult to gather sufficiently comparable research results to make comparisons and reach evidence-based conclusions.

To support the Chinese government's decision-making and to help its departments to establish scientific, long- and short-term vehicle energy strategies, it is urgent to develop an appropriate methodology and computational LCA model that can make comparisons between several vehicle fuel pathways. In recent years, the China Automotive Energy Research Center (CAERC) at Tsinghua University has used the GREET model (which was developed and parameterized for the U.S. energy production chain structure) as a basis for developing the Tsinghua University Life Cycle Analysis Model (TLCAM). The model employs as much localized data as possible to provide comprehensive LCA comparisons between the multiple fuel/vehicle pathways that reflect actual situations in China while using the same modeling platform. The model data are frequently updated to increase their relevance to the current policy-making context. A series of domestic vehicle fuel well-to-wheels (WTW) analyses have been published using TLCAM [23,33–38].

In TLCAM, the primary fossil energy input considers three fuel types: coal, oil, and NG. Nine types of end-use energy are principally analyzed: raw coal, crude oil, raw NG, clean coal, processed NG, diesel, gasoline, fuel oil and electricity. Three key GHGs are considered—CO_2, CH_4 and N_2O—with iterative calculations used to include the upstream contribution to the fossil energy consumption and GHG emissions in the LCA. In this way, TLCAM offers a comprehensive and in-depth understanding of energy consumption and GHG emissions for multiple types of vehicle fuel pathways in China.

1.3. Aim and Structure of This Paper

This paper updates the life cycle primary fossil energy consumption and greenhouse gas intensity of end-use energy options in China. TLCAM is used to analyze the life-cycle GHG emissions and primary fossil energy consumption for gasoline, diesel, coal-based, NG-based and EVs.

Section 2 introduces the methodology, with all key data and assumptions for the researched vehicle fuel pathways detailed in Section 3. Section 4 presents the main results, and focuses on decreases in GHG emissions compared with conventional gasoline and diesel vehicles. The section also includes a sensitivity analysis of the carbon footprint of LNG fuel pathways and a detailed investigation of EVs. The final section (Section 5) provides some concluding remarks.

2. Methodology

2.1. Stages Covered and LCA System Boundary

Strictly speaking, a LCA analysis of energy consumption and GHG emissions for fuel use comprises two parts: the fuel and the vehicle cycles (Figure 1). In this paper, the system boundary for multiple vehicle fuel pathways only includes fuel cycle. However, the energy consumption and GHG emissions attributed to materials production and transportation, vehicle manufacture, vehicle decommissioning and recycling typically accounts for 10–20% of the total life cycle values, and the proportion for EV pathway is particularly higher owing to the material used in and the manufacture of system components (e.g., the battery and electric motor). Vehicle cycle also has been paid much attention in recent years. Therefore, while our study mainly focuses on analyzing the fuel pathways, we also extend the boundary to include the vehicle cycle to analyze the GHG emissions of vehicle and battery production.

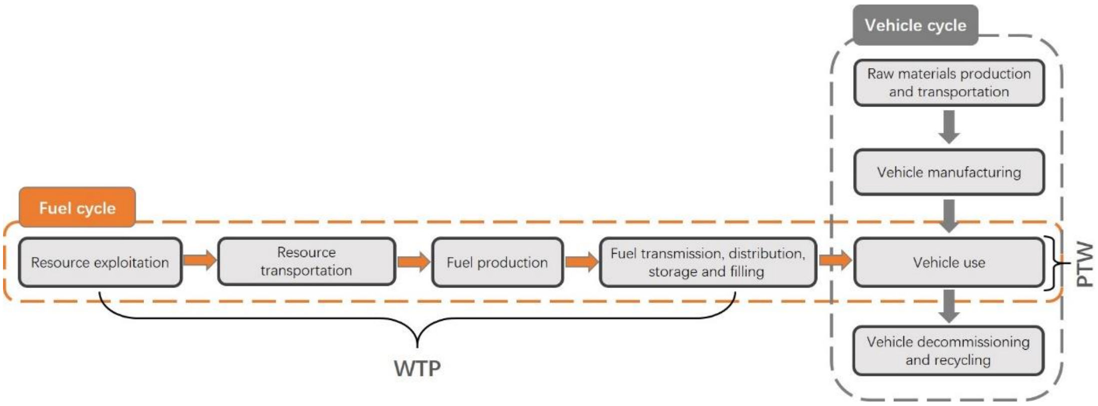

Figure 1. Stages and cycles included in life cycle analysis (LCA) system boundary.

The Well-to-Wheels (WTW) fuel cycle has two stages (as Figure 1 shows). Well-to-Pump (WTP) is the upstream production of the vehicle fuel and includes: resource exploitation and transportation; fuel production, transmission, distribution and storage; and the fuel-filling process. The Pump-to-Wheels (PTW) stage focuses on the fuel combustion and associated emissions from actually using the fuel in a vehicle. The WTW boundary includes the direct use of relevant process and transportation fuel but does not consider indirectly associated energy consumption from plant infrastructure and facilities during their manufacturing or other activities. We used the conventional oil-based pathways as our benchmark transportation fuel pathway. The stages used in the analyses of the other fuels in the study are shown in Table 1. The functional units are MJ/km and g $CO_{2,e}$/km for energy consumption and GHG emissions, respectively, based on vehicle distance.

Table 1. Stages included in Well-to-Well (WTW) analysis for different fuel pathways.

Well-to-Pump (WTP)				Pump-to-Wheels (PTW)
Resource Exploitation	**Resource Transportation**	**Fuel Production**	**Fuel Transmission, Distribution, Storage and Filling**	**Fuel Utilization**
Crude oil exploitation	Crude oil transportation	Refining gasoline, oxygenate refining, and oxygenated gasoline preparation Refining diesel Refining LPG (Liquefied Petroleum Gas)	Gasoline transmission and distribution Diesel transmission and distribution LPG transmission and distribution	Fuel combustion in the internal combustion engine

Table 1. *Cont.*

Well-to-Pump (WTP)				Pump-to-Wheels (PTW)
Resource Exploitation	**Resource Transportation**	**Fuel Production**	**Fuel Transmission, Distribution, Storage and Filling**	**Fuel Utilization**
Coal mining, processing and washing	Coal transportation	Coal gasification and synthesis of methanol	Methanol transmission and distribution	
		Coal gasification and synthesis of DME (Dimethyl Ether)	DME transmission and distribution	
		Production of CtL (Coal to Liquid)	CtL transmission and distribution	
Gas exploitation and purification	NG transportation	NG compression	CNG transmission and distribution	
		NG liquefaction	LNG transmission and distribution	
		GTL (Gas to Liquid) production	GTL transmission and tdistribution	
Crude oil, NG, coal, and other raw materials exploitation and processing	Transportation of raw materials	Raw material electricity generation	Electricity transport, distribution and battery charging	Driving electric motor

2.2. Calculation of Life Cycle Factors for End-Use Energy

In TLCAM, an end-use energy's life cycle fossil energy intensity is defined as the total primary fossil energy consumption required to obtain and use 1 MJ of the end-use energy. We then defined the life cycle GHG emissions intensity as the GHG emissions associated with the production and use of 1 MJ of the end-use energy. Life cycle factors were calculated by the model using an automated iterative method [34]. Fuller details on the calculation methodology and the main data used are presented in the Appendix A.

2.3. Calculation Methods for Life Cycle Intensity for Vehicle Fuel Pathways

The life cycle fossil energy intensity (MJ/MJ) and GHG emissions intensity (g $CO_{2,e}$/MJ) of a specific vehicle fuel pathway were calculated as the sum of all end-use energy consumed across all of the WTW stages multiplied by the life cycle factors of these end-use energies as a process fuel. For vehicle fuel derived from oil, NG and coal sources, the analysis of the intensity of energy and GHG emissions contained two categories: (1) the intensity related to the direct use of the end-use energy (as, for example, in the diesel and gasoline pathways) which was calculated by TLCAM; and (2) taking a given end-use energy as a starting point, we calculated the sum of the total end-use energy consumption and composition for the subsequent production and transport sub-stages. This second stage involved multiplying and summing the corresponding process intensity factors and was used with pathways involving LPG, CNG, GTL, coal-based liquid fuels, and fossil energy electricity generation.

For a given vehicle fuel pathway, we assumed the pathway had n sub-stages (i.e., $p = 1, 2, \ldots, n$) before the fuel was supplied for vehicle use. As Equation (1) shows, the fossil energy intensity was then calculated as the sum of the products of the nine end-use energies (i.e., $j = 1, 2, \ldots, 9$) that were consumed in the various sub-stages (i.e., $p = 1, 2, \ldots, n$) and the associated life cycle energy intensity:

$$E_{LC} = \sum_{p=1}^{n} \sum_{j=1}^{9} \sum_{i=1}^{3} (EN_{p,j} EF_{LC,j,i}) \quad (1)$$

where E_{LC} is the life cycle fossil energy intensity (MJ/MJ) of a given vehicle fuel pathway; $EF_{LC,j,i}$ (MJ/MJ) is the life cycle fossil energy type i intensity of end-use energy type j, which is taken from TLCAM's calculated end-use energy intensity inventory, as described in the Appendix A; and $EN_{p,j}$

(MJ/MJ) is the end-use energy type j that is consumed in sub-stage p. To carry out the calculation, we then obtained the total end-use energy consumption (or energy efficiency) for each sub-stage to acquire $EN_{p,j}$.

For example, for a given CTL pathway, the fossil energy intensity was calculated using the following equations:

$$E_{LC} = \sum_{i=1}^{3} (EN_{plant,4}EF_{LC,4,i} + EN_{plant,9}EF_{LC,9,i} + \sum_{j=1}^{4} (EN_{transport,j}EF_{LC,j,i})) \tag{2}$$

$$EN_{plant,4} = SH_{plant,4}/\eta_{plant} \tag{3}$$

$$EN_{plant,9} = \left(1 - SH_{plant,4}\right)/\eta_{plant} \tag{4}$$

where $EN_{plant,4}$ (MJ/MJ) represents the coal consumed by the chemical plant per MJ of liquid fuel produced; $EN_{plant,9}$ (MJ/MJ) is the coal consumed to produce the electricity used to produce 1 MJ of liquid fuel; $EN_{transport,j}$ (MJ/MJ) is the amount of end-use energy j consumed during the transport of 1 MJ of liquid fuel; $SH_{plant,4}$ is the proportion of coal in the coal chemical plant's total energy consumption; and η_{plant} is the plant's overall energy efficiency.

For electricity pathways, losses during electricity transmission should be considered. For example, for the coal-powered electricity pathway, the calculation of the heat-value-based fossil energy intensity was carried out as follows:

$$E_{LC} = \sum_{i=1}^{3} \left(EN_{plant,4}EF_{LC,4,i}\right) \tag{5}$$

$$EN_{plant,4} = 1/\left(\eta_{plant}(1 - R_{trans})\right) \tag{6}$$

where R_{trans} represents the losses during electricity transmission.

Life cycle GHG emissions were calculated using the CO_2-equivalent global warming potentials to directly sum the three main GHG emission intensities (CO_2, CH_4 and N_2O) [39,40]:

$$GHG_{LC} = CO_{2,LC} + 25CH_{4,LC} + 298N_2O_{LC} \tag{7}$$

Each of the GHG emission intensities ($CO_{2,LC}$, $CH_{4,LC}$ and N_2O_{LC}) was determined by summing the product of the end-use energy and the corresponding GHG emission intensity for each sub-stage ($CO_{2,LC,j}$, $CH_{4,LC,j}$ and $N_2O_{LC,j}$):

$$CO_{2,LC} = \sum_{p=1}^{n} \sum_{j=1}^{9} (EN_{p,j}CO_{2,LC,j}) \tag{8}$$

$$CH_{4,LC} = \sum_{p=1}^{n} \sum_{j=1}^{9} (EN_{p,j}CH_{4,LC,j}) \tag{9}$$

$$N_2O_{LC} = \sum_{p=1}^{n} \sum_{j=1}^{9} (EN_{p,j}N_2O_{LC,j}) \tag{10}$$

For grid electricity, weighting was attributed to the different electricity pathways, W_q ($q = 1, 2 \ldots ,$). The energy intensity and GHG emission intensity of grid electricity was then calculated as follows:

$$E_{LC} = \sum_{q} \left(W_q E_{LC,q}\right) \tag{11}$$

$$GHG_{LC} = \sum_{q} \left(W_q GHG_{LC,q}\right) \tag{12}$$

where $EF_{LC,q}$ (MJ/MJ) is the life cycle fossil energy intensity and $GHG_{LC,q}$ (g $CO_{2,e}$/MJ) is the life cycle GHG emissions intensity of the electricity pathway q.

2.4. Life Cycle Energy Use and GHG Emissions per km

When the vehicle efficiencies were taken into consideration, through multiplying the life cycle results of each fuel pathway by fuel efficiency, FE (km/MJ), we calculated the life cycle fossil energy input, $E_{LC,dist}$ (MJ/km), and the GHG emissions, $GHG_{LC,dist}$ (g $CO_{2,e}$/km), per km of distance driven by the vehicle.

$$E_{LC,dist} = EF_{LC}FE \tag{13}$$

$$GHG_{LC,dist} = GHG_{LC}FE \tag{14}$$

3. Data and Assumptions

3.1. Basic Data and Parameters

The main data for the calculation of EF_{LC} and GHG_{LC} for the nine end-use energy options are listed in Appendix A. Table A2 presents original, China-specific data for oil-, NG-, and coal-based fuels and electricity. It includes energy conversion efficiencies, transport distances and the proportion of the different process fuels used in the various resource exploitation, transport, fuel processing and fuel production stages. The energy intensity and breakdown of fuels used by various transport modes are shown in Table A3. Together with the transport fuels' lower heating values (MJ/kg), these data were then used to calculate the process fuel consumption to transport 1 MJ of feedstock or fuel to the end user. Direct and indirect GHG emissions released from the use of various energies in the Chinese context are shown in Table A4. Data on carbon content (CC_j, g/MJ), fuel oxidation rate (FOR_j, g/MJ), and the direct CH_4 ($CH_{4,direct}$, g/MJ) and N_2O (N_2O_{direct}, g/MJ) emission factors were taken from authoritative literature [33–39]. Indirect CH_4 emissions from non-combustion sources, including spills and losses during the resource extraction stage, were calculated using TLCAM.

3.2. Oil-Based Fuel Pathways

Imported and domestically produced crude oil needs to be transported to refineries across the country for refining. Refining oil products is a poly-generation process, and therefore it is necessary to proportion the distribution of energy consumption by the process among the various products. Average energy efficiency assumptions were based on a literature review. The energy efficiency of gasoline and diesel is shown in Table A2, and an energy efficiency of LPG plant was assumed to be 90.3% according to [41]. This value is unlikely to change substantially, even in the long term. For the energy consumption structure shown in Table A2, end-use energy consumption data for oil processing, coal coking and nuclear fuel processing was taken from the China Energy Statistical Yearbook 2016 [42].

Data relating to the transmission and distribution of gasoline, diesel and fuel oil is shown in Table A1. Similar data for LPG are shown in Table 2.

Table 2. LPG transmission and distribution parameters [34].

Modes of Transport	Ocean	Railway	Pipeline	Water	Highway
Proportion (%)	30	80	0	15	10
Average transport distance (km)	7000	900	0	1200	50

Note: The sum of the proportions of individual transport modes may exceed 100%.

3.3. NG-Based Fuel Pathways

The main component of NG is the GHG methane (CH_4). Leakage during the exploitation and processing of NG can have powerful GHG emission effects, potentially affecting the overall pathway's energy savings and associated decrease in GHG emissions. The amount of fugitive CH_4 during NG exploitation activities was assumed to be 0.34%.

Table 3 shows the energy efficiencies for the CNG, LNG and GTL pathways. LNG was divided into three types: imported LNG (LNG 1); LNG that was liquefied near to a domestic gas field (LNG 2); and liquefaction of NG post-transported via pipelines in China (LNG 3).

Table 3. Energy efficiencies for the different NG-based fuel pathways [7,23].

NG-Based Fuel	Energy Efficiency (%)	Process Fuel Mix
CNG	96.9%	NG (97%) and electricity (3%)
LNG 1	91.0%	NG (98%) and electricity (2%)
LNG 2	95.19%	Electricity (100%)
LNG 3	95.19%	Electricity (100%)
GTL	54.20%	NG (100%)

Parameters relating to the transmission and distribution of CNG, LNG and GTL are listed in Table 4. The WTW analysis of NG-based vehicle fuels is sensitive to the distance and mode by which NG is transported, which necessitated careful setting of these parameters. Given that CNG vehicles are mainly used in regions with rich NG resources, we assumed that the NG transport distance for CNG production was 300 km. CNG is directly used by vehicles, meaning that there was no further transmission and distribution included in the model. For LNG 1, after 6700 km of transport by ship, the LNG was assumed to be used after a short-distance transmission and distribution system. LNG 2 was directly liquefied at a domestic gas field and then transported by road for use. LNG 3 was transported via pipelines (1500 km), then liquefied and injected into a transmission and distribution system that was assumed to cover an average distance of 100 km. Plants producing GTL and other liquid fuels are always constructed near gas fields in China, so we assumed that NG was transported 100 km to the plant via a pipeline from the gas field. The transmission and distribution modes of GTL were then assumed to be the same as those of conventional diesel.

Table 4. Transmission and distribution parameters for NG-based fuels [23].

NG-Based Fuel	Transport Mode
CNG	- -
LNG 1	Waterway: 100% (6700 km), Road vehicle: 100% (100 km)
LNG 2	Road vehicle: 100% (100 km)
LNG 3	Road vehicle: 100% (100 km)
GTL	Railway: 50% (900 km); pipeline: 15% (160 km); waterway: 10% (1200 km); road (short distance): 10% (50 km)

3.4. Coal-Based Fuel Pathways

Four CtL vehicle fuel pathways were included: methanol blended into vehicle gasoline; dimethyl ether (DME); and the direct and indirect production of synthetic oil productions from coal liquefaction. Many domestic plants, with varying energy efficiencies and fuel mixes, currently produce such fuels using coal as the raw material. For the direct CtL and indirect CtL (ICtL) pathways, we assumed that no extra electricity was needed, besides that supplied by the production plant's in-house electricity generation units. Details of the relevant assumptions are listed in Table 5.

Table 5. Energy efficiencies and process fuels for fuels produced via different CTL processes [33,41].

Coal-Based Product	Energy Efficiency	Process Fuel Mix
Coal-based methanol	50.22%	Coal (91%) and electricity (9%)
Coal-based DME	47.46%	Coal (93%) and electricity (7%)
Direct CtL	49.30%	Coal (100%)
Indirect CtL	41.41%	Coal (100%)

Different modes of transport can be employed for coal consumed in electricity production or in the production of coal-based vehicle fuels. Generally, such production plants are built near coal mines. Thus, based on existing plants, coal was assumed to be transported for 30 km by truck to reach the coal field from coal mines, and then 20 km by truck to reach the plants from coal field. Subsequent transmission and distribution of ethanol, DME, and coal-based liquid fuels were then assumed to be the same as for conventional diesel (Table A2).

3.5. Electricity Pathways

Relevant data for coal-, oil- and NG-based thermal electricity pathways are listed in Table A2. Hydro, nuclear, solar, biomass, and other forms of electricity generation also account for a sizable proportion of China's electricity supply. As shown in Table 6, the fossil energy consumption by hydro, wind, and solar electricity is negligible [33,43,44]. However, emissions associated with facility construction and decommissioning should not be omitted. Especially for hydroelectricity, the creation of the reservoir can cause CO_2, CH_4 and other GHG emissions related to the biological degradation of vegetation. The life cycle emission factors of these power-generating options were approximated as 5 g $CO_{2,e}$/MJ.

Table 6. Life cycle energy-use intensity and GHG-emissions intensity of non-fossil electricity-generating pathways.

Electricity Type	Fossil Energy Use (MJ/MJ)	GHG Emissions (g $CO_{2,e}$/MJ)	Data Source
Nuclear	0.063	6.506	[33]
Biomass	0.076	5.846	[43]
Hydro and Others	0	5	[44]

3.6. Carbon Dioxide Capture and Storage (CCS) Technology

Studies on the application of CCS technology for coal-burning plants suggest that an extra 80–160 kWh of electricity is required per ton of compressed CO_2 obtained at a CO_2 capture rate of approximately 90% [41,45–47]. We therefore assumed a figure of 140 kWh/t CO_2, which corresponded to a decrease in the plant's efficiency of 10% (for example from 40% to 30%). For the CO_2 transport and storage stages, we assumed that energy consumption was negligible when compared with that of the capture stage.

3.7. Vehicle Size and Fuel Efficiency

The fuel economy of a mid-sized passenger vehicle was assumed to be 8 L of gasoline per 100 km. Taking the internal combustion engine (ICE) gasoline vehicle as the base case here, comparisons were then made by employing the fuel economy values of other combinations of vehicles and fuel production pathways (Table 7). WTW analysis results for various vehicle technologies were then calculated and compared for different fuels on a per km basis.

Table 7. PTW efficiency for various vehicle fuels in China [33,35,48].

Vehicle Fuel Type	Vehicle Power Technology Type	Running Distance per Unit of Energy (%) (Base = 100%)	Energy Consumption per Unit of Distance (Base = 1.00)
Gasoline	ICE	100.0	1.00
Diesel	ICE	109.9	0.91
LPG	ICE	95.2	1.05
CNG	ICE	95.2	1.05
LNG	ICE	99.7	1.00
GTL	ICE	120.0	0.83
Ethanol	ICE	100.0	1.00
Methanol	ICE	100.0	1.00
DME	ICE	105.0	0.95
Biodiesel	ICE	109.9	0.91
Direct CtL	ICE	117.6	0.85
Indirect CtL	ICE	98.0	1.02
Electricity	Electromotor	351.0	0.28

4. Results and Discussion

4.1. Life Cycle Primary Fossil Energy and Carbon Intensity of End-Use Energy in China

TLCAM model was used to recalculate and update the life cycle fossil energy and GHG emissions intensities of China's major end-use energy options for 2015, as shown in Table 8.

Table 8. Calculated life cycle fossil energy and GHG emissions intensities for China in 2015.

Item	EF_{LC}	$EF_{LC,Coal}$	$EF_{LC,NG}$	$EF_{LC,Oil}$	GHG_{LC}	$CO_{2,up}$	$CH_{4,up}$	N_2O_{up}
Unit	MJ/MJ	MJ/MJ	MJ/MJ	MJ/MJ	$gCO_{2,e}$/MJ	g/MJ	g/MJ	mg/MJ
Raw coal	1.071	1.068	0.001	0.002	98.3	5.776	0.434	0.127
Raw NG	1.141	0.041	1.052	0.048	67.5	9.660	0.093	0.403
Crude oil	1.097	0.028	0.036	1.033	79.2	6.692	0.024	0.279
Clean coal	1.086	1.070	0.002	0.014	99.4	6.846	0.435	0.377
processed NG	1.145	0.041	1.056	0.048	69.3	9.934	0.093	0.409
Diesel	1.259	0.066	0.047	1.146	92.3	18.575	0.041	0.406
Gasoline	1.268	0.068	0.047	1.153	90.2	19.216	0.042	0.411
Fuel oil	1.197	0.052	0.042	1.102	90.8	14.022	0.034	0.360
Electricity	2.250	2.140	0.075	0.035	203.4	181.507	0.877	2.848

4.2. Life Cycle Primary Energy Use of Multiple Vehicle Fuels

The primary energy consumption (total WTW fossil energy input) and energy conversion efficiency (the ratio between the heat value of the end-use fuel and WTW fossil energy input) for the various vehicle fuel pathways calculated by TLCAM are presented in Table 9. We found that oil- and NG-based gaseous fuels consumed similar amounts of primary fossil energy, from 1.198 to 1.282 MJ/MJ, with energy conversion efficiencies from 77.97% to 83.49%. GTL and coal-based fuel pathways ranked behind those based on oil with primary fossil energy inputs ranging from 2.141 to 2.629 MJ/MJ and energy conversion efficiencies from 38.03% to 46.71%. With application of CCS technology, the WTW fossil energy consumption of coal-based fuel pathways increased further (2.532–3.298 MJ/MJ), further decreasing the energy conversion efficiencies (30.32–39.49%). For the electricity pathways, at 4.030 MJ/MJ, the WTW fossil energy consumption input was particularly high for oil-fired electricity generation, with a conversion efficiency of just 24.81%. By contrast the WTW fossil energy consumption for nuclear- and biomass-powered electricity generation pathways were low, and negligible for that employing hydropower. The fossil energy consumption for the averaged grid electricity pathway was 2.250 MJ/MJ, reflecting the various sources of electricity that make up the grid's electricity supply. The average energy conversion efficiency was 44.45%.

The primary fossil consumption results indicate that non-oil-based pathways can achieve a significant "oil-substitution effect" from a WTW life cycle point of view.

Table 9. Primary energy consumption and energy conversion efficiency of vehicle fuel pathways.

Pathway	Energy Consumption (MJ/MJ)				Energy Conversion Efficiency (%)
	Coal Consumption	Oil Consumption	NG Consumption	Total Consumption	
Gasoline	0.072	0.052	1.158	1.282	77.98
Diesel	0.070	0.051	1.151	1.273	78.57
LPG	0.049	0.047	1.161	1.257	79.57
CNG	0.071	1.120	0.006	1.198	83.49
LNG1	0.015	1.228	0.040	1.282	77.97
LNG2	0.113	1.118	0.013	1.244	80.37
LNG3	0.116	1.129	0.014	1.259	79.44
GTL	0.043	2.046	0.052	2.141	46.71
Coal-based methanol	2.297	0.012	0.049	2.358	42.40
Coal-based DME	2.417	0.011	0.053	2.480	40.32
CtL	2.172	0.004	0.034	2.210	45.25
ICtL	2.586	0.004	0.039	2.629	38.03
Coal-based methanol + CCS	2.720	0.018	0.060	2.797	35.75
Coal-based DME + CCS	2.853	0.017	0.063	2.933	34.09
CtL + CCS	2.490	0.004	0.038	2.532	39.49
ICtL + CCS	3.244	0.005	0.048	3.298	30.32
Grid electricity	2.140	0.075	0.035	2.250	44.45
Coal electricity	3.147	0.005	0.042	3.194	31.31
Oil electricity	0.184	0.150	3.696	4.030	24.81
Gas electricity	0.017	2.625	0.013	2.656	37.65
Nuclear electricity	0.052	0.005	0.006	0.063	–
Biomass electricity	0.01	0.002	0.064	0.076	–
Hydropower and Others	0	0	0	0	–

4.3. Life Cycle GHG Emissions Footprint of Different Vehicle Fuels

The life cycle GHG emissions per MJ of vehicle fuel produced and used for the various production/consumption stages are shown in Figure 2. The results indicate that, apart for biomass-powered electricity, GHG emissions associated with transportation (of both raw materials and fuel products) contributed very little to the total life cycle emissions (from 0.22% to 3.15%).

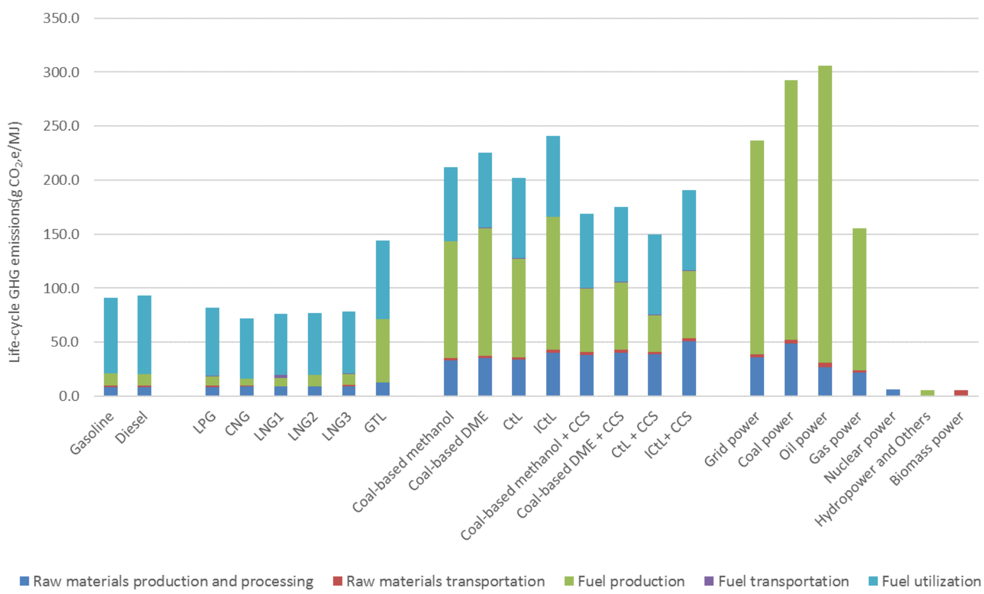

Figure 2. Life cycle GHG emissions for various vehicle fuels by stage.

4.3.1. Oil-based Fuel Pathways

The life cycle GHG emissions for gasoline, diesel and LPG were 91.3, 93.3 and 82.2 g $CO_{2,e}$/MJ, respectively. For oil-based fuel pathways, GHG emissions in the (upstream) WTP stages accounted for a modest fraction of the total emissions: 23.41%, 22.11% and 23.25% for gasoline, diesel and LPG, respectively. Meanwhile, for the same fuels, GHG emissions from the fuel-use stage dominated the WTW totals at 76.59%, 77.89% and 76.75%, respectively. During fuel use, GHG emissions from different fuel pathways are defined by the physical properties of the fuel, including their carbon content (CC) and the fuel oxidation rate (FOR).

4.3.2. NG-Based Fuel Pathways

At 72.3 g $CO_{2,e}$/MJ, life cycle GHG emissions for CNG were a little lower than those of conventional oil-based fuels, with 21.95% of the total attributed to upstream processes. The total GHG emissions for GTL were 143.9 g $CO_{2,e}$/MJ with a similar proportion attributed to upstream processes (49.53%) and fuel use phase (50.47%). Regarding the LNG pathways, all GHG emissions associated with LNG 2 and LNG 3 were released within domestic boundaries. The emissions for LNG 2 and LNG 3 were 77.2 and 78.1 g $CO_{2,e}$/MJ, respectively, of which 25.99% and 26.90%, respectively, were attributed to upstream processes. For LNG 1, the upstream GHG emissions, which were assumed to be emitted outside of national boundaries, were 19.50 g $CO_{2,e}$/MJ, 25.69% of the total (76.1 g $CO_{2,e}$/MJ). These included NG exploitation and processing, NG liquefaction, and LNG transport to China, which accounted for 12.89%, 10.30%, and 2.50% of the total, respectively. The GHG emissions associated with LNG transmission and distribution, and LNG use, which were assumed to occur in China, represented 56.42 g $CO_{2,e}$/MJ, or 74.31% of the total life cycle emissions.

4.3.3. Coal-Based Fuel Pathways

The life cycle GHG emissions for the methanol, DME, direct CtL and ICtL pathways were 212.1, 225.3, 202.1 and 240.6 g $CO_{2,e}$/MJ, respectively, which were 2.2–2.6 times greater than those associated with conventional gasoline. The main reasons for such high values were the low energy conversion rates of coal-based fuel plants and the associated consumption of primary fossil energy, especially of coal with its very high carbon content. The GHG emissions from the upstream stages outweighed those from fuel use, ranging from 63.24% to 69.22% of the total. Introducing CCS decreased the life cycle GHG emissions of the methanol, DME, direct CtL and ICtL pathways by 20.45%, 22.29%, 26.04% and 20.67%, respectively. Simultaneously, the contribution from upstream operations fell to 59.41%, 60.39%, 50.30% and 61.07% of the total for the respective pathways.

4.3.4. Electricity (for EV) Pathways

For the EV pathways, almost all of the GHG emissions were generated in the upstream, fuel-production stage. The total GHG emissions associated with coal-derived electricity was 292.3 g $CO_{2,e}$/MJ, in which the production, transportation and combustion of coal accounted for 16.72%, 1.10% and 82.17%, respectively. Similarly, GHG emissions associated with the production and transportation of oil in the oil-powered electricity pathway accounted for 8.74% and 1.44% of the total life cycle emissions, respectively. Adding the GHG emissions from its combustion in a power plant, the total GHG emissions for oil-derived electricity were 305.7 g $CO_{2,e}$/MJ. The corresponding life cycle GHG emissions for gas-derived electricity were 155.5 g $CO_{2,e}$/MJ, of which raw material production and transportation were responsible for 13.94% and 1.45%, respectively. Electricity pathways with non-fossil energy as the main raw material (such as nuclear, biomass and hydropower) had very small life cycle GHG emissions. Here, emissions tended to be concentrated in a specific sub-stage. For example, nearly all of the GHG emissions from of biomass-derived electricity was generated by transporting the raw material. The GHG emissions associated with the average grid electricity chain were 168 g $CO_{2,e}$/MJ, with raw material production, raw material transportation and generation in the electricity plant accounting for 15.18%, 1.13% and 83.69%, respectively.

4.4. Comparison between NG-Based and Electricity Pathways

Table 10 shows a comparison of the varied results for NG-based and electricity pathways for studies conducted in China and several other countries. The current study updates previous work on China by considering the most up-to-date production technology that is in use in China today. Thus, fuel-conversion efficiencies are for the most part higher (Table A2), leading to a lower overall level of energy consumption and GHG emissions for the processes.

Nonetheless, the life cycle consumption of primary fossil energy and GHG emissions for the NG-based fuels and electricity pathways in China remained higher than those in other countries and regions. For electricity pathways, the difference is mainly due to the low proportion of low-carbon sources (29.1%) and the large proportion of coal electricity (67.9%) in China's electricity mix [49], the latter being significantly higher than in the other countries in the comparison (0–34.3%) [7]. For NG-based fuel pathways, the differences can be attributed to: (1) China's coal-dominated energy mix; (2) China's lower efficiencies in the feedstock and fuel production stages (for example, for the CNG pathway, NG extraction, processing and CNG compression efficiencies in China were 96%, 94% and 96.9%, respectively [23,34], while the respective values for the US were 98%, 98% and 97.9% [7]); and (3) China's higher energy intensities for various transport modes [32,34].

Table 10. Energy consumption and GHG emission intensity results for NG-based and electricity pathways from different studies.

Pathway	Region	Energy Intensity (MJ/MJ)	GHG Intensity (g $CO_{2,e}$/MJ)	Data Source
Electricity	China	2.25	203	This study
Electricity	China	2.70	230	[16]
Electricity	China	2.33	230	[7]
Electricity	US	1.92	162	[7]
Electricity	Europe	1.52	116	[14]
CNG	China	1.20	72	This study
CNG	China	1.46	–	[32]
CNG	China	1.23	78	[31]
CNG	US	1.16	77	[7]
CNG	Europe	1.19	71	[14]
LNG	China	1.28/LNG 1, 1.24/LNG 2, 1.26/LNG 3	75.9/LNG 1, 77.2/LNG 2, 78.1/LNG 3	This study
LNG	US	1.21	76.4	[7]

4.5. Comparison for WTW Results of Vehicle Fuels

As shown in Figure 3, the life cycle primary fossil energy consumption for the various vehicle fuels investigated was broadly ordered (from highest to lowest) as follows: coal-based fuels, GTL, conventional oil-based fuels, LNG, CNG, CCS-fitted electricity generation, generation I biofuels, grid-powered electricity, and generation II biofuels.

As shown in Figure 4, the order for life cycle GHG emissions was as follows (again, from highest to lowest): coal-based fuels, coal-based fuels with CCS, waste oil-derived biodiesel, GTL, conventional oil-based fuels, generation I biofuels, gaseous and liquefied NG fuels, grid-powered electricity, CCS-fitted power generation and generation II biofuels.

Here we refer to the WTW analyses results of biofuel vehicle pathways and coal electricity with CCS [35] in the previous reports [33,41] by CAERC using TLCAM to gain a more comprehensive understanding of energy consumption and GHG emissions for the different vehicle fuel pathways calculated in this study.

Fuels derived from a coal-powered process that was not equipped with CCS showed fossil energy inputs and GHG emissions that were 47–132% and 88–189% higher than those for conventional gasoline and diesel pathways, respectively. This was attributed to low conversion efficiencies in coal-powered fuel plants and coal's high carbon content. Coal-powered methanol and DME plants in China are decentralized with the level of technology employed varying greatly, suggesting that the average value used here may mask a wide distribution of results. The application of CCS technology further increased the life cycle fossil energy inputs of coal-based fuel pathways. This resulted in life cycle primary energy consumption being 68–191% higher than in the conventional diesel and gasoline pathways, with the corresponding GHG emissions being 39–129% higher. Uncertainties surrounding CCS's energy consumption and rate of carbon capture could further extend the range of real-world results for pathways that apply CCS.

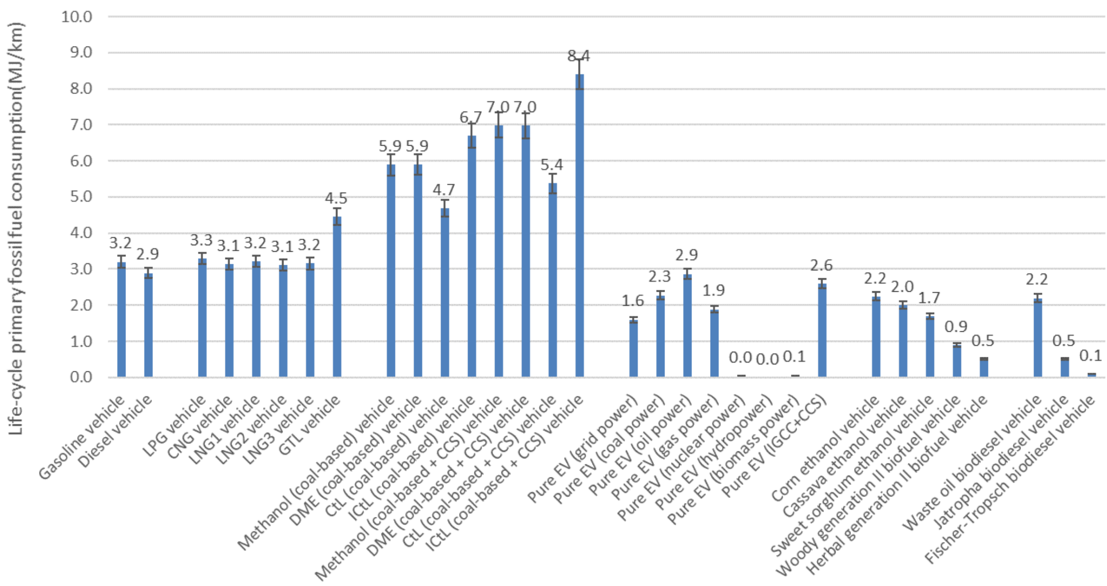

Figure 3. Life cycle primary fossil fuel consumption for various vehicle fuels (vehicle cycle excluded).

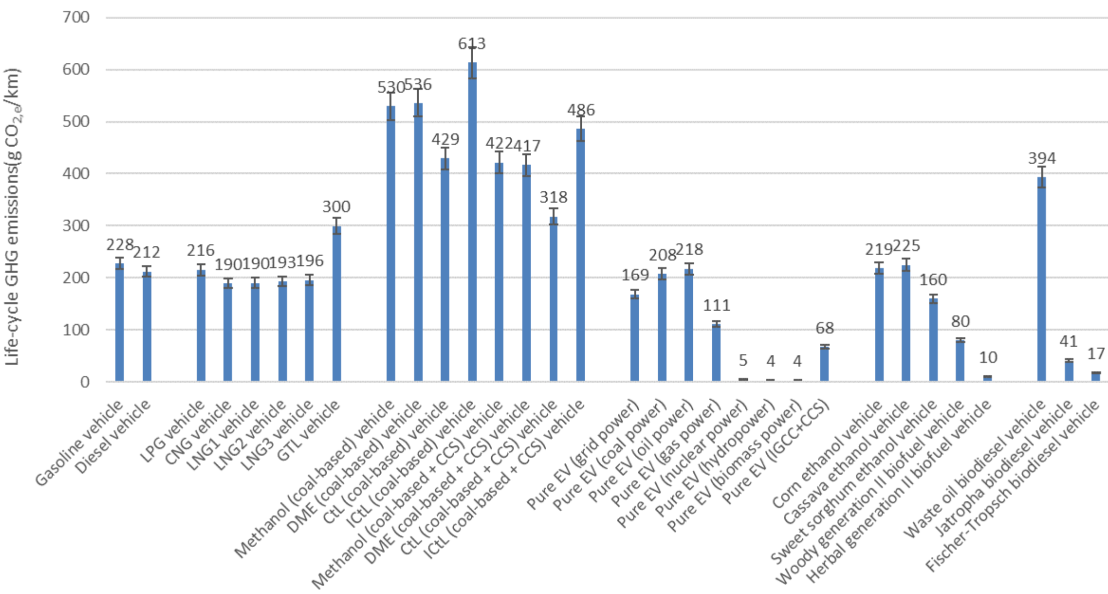

Figure 4. Life cycle GHG emissions for various vehicle fuels (vehicle cycle excluded).

While the life-cycle fossil energy consumption of the CNG and LNG pathways were almost the same as those for the conventional gasoline pathway, because the carbon content of NG is lower than that of oil, the CNG and LNG pathways reported lifecycle GHG emissions that were 14–17% lower than those for the conventional gasoline pathway, and 8–10% lower than those for the conventional diesel pathway. For LNG 1, domestic GHG emissions were 35% and 31% lower than those for conventional gasoline and diesel vehicles, respectively. Variance in results for CNG and LNG pathways can mainly be attributed to differences in the transport distance. For GTL pathways, life cycle fossil energy consumption was 54% greater than that for conventional diesel vehicles because the production efficiency of a GTL plant is relatively low. However, NG's lower carbon content meant that life cycle GHG emissions were only 41% higher than those from conventional diesel vehicles. Variability in current and future conversion efficiencies for GTL plants could create a wide distribution around this average result.

Life cycle fossil energy consumption of EVs using grid electricity was 50% of that consumed by a comparable gasoline vehicle, and 55% of the amount consumed by a comparable diesel vehicle. This decrease was mainly attributed to the much higher energy efficiency of EVs compared with that of ICEs. Because coal is the major source of electricity generation in China, the EV-pathway GHG emissions were only 26% and 21% less than those for conventional gasoline and diesel vehicle pathways, respectively. Using electricity derived solely from coal or oil resulted in very similar results to those obtained for the conventional diesel vehicle pathway. However, using nuclear, biomass or hydro-electricity resulted in WTW fossil energy inputs and GHG emissions that were only 1–2% of those for conventional gasoline and diesel vehicle pathways.

Biofuels offer obvious potential to decrease fossil energy consumption and GHG emissions. Vehicles powered by Generation I biofuels were found to effect 1–30% decreases in GHG emissions and 30–47% decreases in the consumption of fossil energy inputs compared with results for conventional gasoline vehicles. The life cycle fossil energy consumption for the pathway based on waste oil biodiesel was 69% of that consumed for a comparable gasoline vehicle; however, life cycle GHG emissions were 73% higher than comparable diesel vehicle. For generation II biofuel vehicles, life cycle fossil energy consumption and GHG emissions were 72–97% and 65–93% lower than the comparable gasoline/diesel vehicle, respectively.

4.6. Sensitivity Analysis of Carbon Footprint of LNG Pathways and Coal-Based Fuel Pathways

From the analysis of the three LNG pathways considered, the efficiency of NG liquefaction and the mix of fuel during liquefication process impacted the GHG emissions intensity the most. Emissions intensity was only weakly sensitive to changes in the distance over which NG was transported and over which LNG was transmitted and distributed. Specifically, for the LNG 1 pathway, if we were to assume that the foreign liquefaction plant was powered by electricity and had an overall energy efficiency of 95.2%, re-calculation of the life cycle value yields a GHG emissions intensity of 79.1 g $CO_{2,e}$/MJ, a 4.1% increase over a situation where the plant is powered by NG. For the LNG 2 pathway, if we assume that the liquefaction plant is powered by NG and has an overall energy efficiency of 90.2%, the total GHG emissions intensity would be 74.7 g $CO_{2,e}$/MJ, a 3.2% decrease compared with the plant being powered by electricity. For the LNG 3 pathway, if we assume that the liquefaction plant is powered by NG and has an overall energy efficiency of 90.2%, the total GHG emissions intensity would be 75.7 g $CO_{2,e}$/MJ, 3.15% lower than when the plant is powered by electricity. Meanwhile, a 50% decrease in NG transportation and LNG transmission and distribution distances results in GHG emissions intensities for the three pathways changing from 75.9, 77.2 and 78.1 g $CO_{2,e}$/MJ to 75.4, 76.9 and 77.4 g $CO_{2,e}$/MJ, respectively, representing respective decreases of 0.65%, 0.31% and 0.93%.

Compared to LNG pathways, coal-based fuel pathways were more sensitive to energy efficiency and the process fuel mix. For Direct CtL, ICtL, Methanol and DME pathways, if we were to assume that the overall energy efficiencies were 5% lower than before, the GHG emissions intensities would be 212.8, 253.2, 225.3 and 239.1 $CO_{2,e}$/MJ, respectively, representing respective increase of 5.3%, 5.3%, 6.3% and 6.1%. For the four coal-based fuel pathways, if we assume that 50% of the process fuel were from extra electricity, the total GHG emissions intensities would be increased to 325.6, 387.8, 255.3 and 274.6 $CO_{2,e}$/MJ, respectively, representing respective increase of 61.1%, 61.1%, 20.4% and 21.9% over the original situation. Meanwhile, a 50% decrease in coal transportation and coal-based fuel transmission and distribution distances results in GHG emissions intensities for the four pathways decreasing from 202.1, 240.6, 212.1 and 225.3 $CO_{2,e}$/MJ to 200.8, 239.0, 210.8 and 223.9 $CO_{2,e}$/MJ, respectively, representing respective decrease of 0.69%, 0.67%, 0.65% and 0.64%.

4.7. Impact of Expanding the System Boundary to Vehicle Cycle

Energy consumption and GHG emissions attributed to materials production and transportation, vehicle/battery manufacture, vehicle decommissioning and recycling typically are important in LCA but this kind of works are relied on credible data heavily. Referring to Qiao et al. [50], shown in Table 11, if vehicle lifetime was assumed to be 200,000 km, we could estimate the life cycle energy consumption of a standard mid-size BEV with $Li(NiCoMn)O_2$ (NMC)/$LiFePO_4$ (LFP) and an ICEV are 0.46/0.47 and 0.32 MJ/km, respectively, accounting for 44.3%/44.8% and 21.9% of the whole fuel cycle. The life cycle GHG emissions are 75.0/75.9 and 49.9 g $CO_{2,e}$/km, respectively, representing 28.9%/29.5% and 9.9% of the whole fuel cycle. The life cycle GHG emissions from the production of a BEV with NMC/LFP and a ICEV are 14.6/14.7 and 9.2 t $CO_{2,e}$. in earlier study [51]. Especially for the production of traction battery, the life cycle GHG emissions are significant, ranging from 2.7 to 3.1 t $CO_{2,e}$ in China [50–52]. The total energy consumption and GHG emissions resulted from vehicle cycle can be reduced largely when considering most of the material in the vehicles can be recycled though the impact was still obvious and could not be negligible [53].

Table 11. Life cycle energy consumption and GHG emissions from vehicle cycle [50].

	Unit	ICEV	BEV-NMC	BEV-LFP
Life cycle energy consumption	MJ/per vehicle	63.515	92,392	94,341
Life cycle GHG emissions	kg $CO_{2,e}$/per vehicle	9985	15,005	15,174

Both the life cycle energy consumption and GHG emissions of a BEV were higher than those of an ICEV [50–53]. Compared with an equivalent ICEV, a BEV has a different motor, a traction battery and several other new systems that mean the life cycle results of vehicle cycle would be different due to the production of these new and additional components. For various ICEV pathways, the components of standard middle-size passenger vehicles are basically the same, with tiny difference among them such as spark plug. Thus, we assumed that the total GHG emissions from ICEV production were the same for different vehicle/fuel pathway in this paper.

In other words, the inclusion of the vehicle cycle can improve the life cycle analysis method and update the existing results significantly. As shown in Figure 5, the total life cycle GHG emissions of a BEV charged by grid power is only 12% less than that of a gasoline vehicle. Particularly, coal -and oil-powered BEVs caused more GHG emissions than gasoline vehicles, due to that BEVs tended to have larger battery and new components which lead to higher emissions.

Three major factors were analyzed for sensitivity by Qiao et al. [50], including curb weight, GHG emissions factor of electricity production and traction battery. The results indicated that when the curb weight is changed by 10%, the GHG emissions from the production of a BEV with NMC/LFP and a ICEV would be influenced by 7.3%, 6.7% and 6.6%, respectively. Amounts of electricity is consumed during vehicle production, the result showed that the value respective were 3.7%, 3.8% and 3.9%, respectively, when the GHG emissions factor of grid mix changes by 10%.

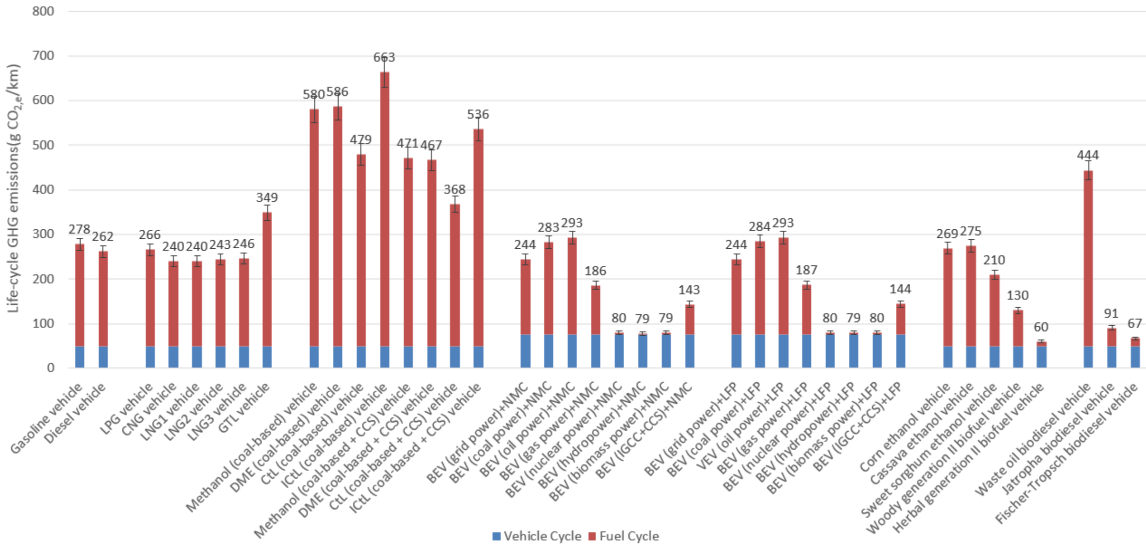

Figure 5. Life cycle GHG emissions for various vehicle fuels (vehicle cycle included).

4.8. Limitations and Further Work of Our Work

It should be noted that this analysis was not strictly compliant with the guidelines of ISO 14040 and 14044 and could not do compilation and evaluation of potential environmental impacts of a product system throughout its life cycle. However, as a very important method in energy system analysis, life cycle analysis method has been widely used globally. A great number of researchers have made efforts to conduct the life cycle analysis of different products and technical pathways. With the increasing demand of vehicle energy and global warming, life cycle energy consumption and GHG emissions have become critical and necessary information influencing the implementation of relevant energy policies, thus most of the studies mainly focus on the two indicators, but did not analyze all relevant environmental impacts as Zah et al. [54] done. To be honest, our analysis did also not fulfil the requirement of ISO standard, though we have made great effort to investigate the energy consumption and GHG emission of vehicle fuel in China.

In addition, the infrastructure and facilities manufacturing such as power plant and oil drilling, and maybe also the abrasive emissions were all important parts of LCA. They were excluded in the system boundary of this study and the significance of them deserve investigating with more credible data.

Furthermore, this analysis only took three types of primary fossil energy input into consideration, this limitation might underestimate the impact of non-fossil fuel energy such as nuclear power and renewable energy, thus the indicator based on cumulative energy consumption would be much more meaningful and practical than our current study.

One more limitation of our analysis is the full evaluation on non-fossil fuel energy has not been taken though the energy consumption and GHG emissions performance is investigated. Some scholars are arguing that the development of non-fossil fuel energy has broader and environmental impacts and cannot be ignored. For example, radioactive emissions are important for the full environmental impacts of nuclear power development.

Accordingly, plenty of works will be further taken to improve our work in future in two key dimensions, to expand the system boundary and to cover full environment impacts analysis.

5. Conclusions

This work has shown that it is important to include China-specific characteristics in the LCA of alternative fuel vehicles in China. The following specific conclusions may be drawn:

(1) China's current energy system is dominated by coal with a low overall energy efficiency. Together, these facts hinder the realization of potential decreases in fossil energy consumption and GHG emissions that alternative fuels may offer for vehicles, even if they are able to replace oil as the primary energy source.
(2) The potential for decreasing the consumption of fossil energy and GHG emissions for the EV pathways, will be more easily realized in the future. Compared with a conventional ICE vehicle driven by coal-derived liquid fuel, coal-powered EV pathways will offer obvious advantages in the future. EV pathways that are powered by a low-carbon electricity grid offer the most potential for future alternative vehicle fuels.
(3) NG-based fuel pathways showed similar levels of fossil energy consumption and GHG emissions to those for conventional gasoline and diesel vehicles. If only domestically emitted GHGs are considered, the emissions for vehicles in China powered by imported LNG are approximately a third less than for conventional gasoline and diesel vehicles.
(4) The GHG emissions intensity and energy intensity of conventional coal-based fuel pathways are approximately 1.5–2.6 and 1.1–2.6 times greater, respectively, than those of the conventional gasoline pathway. Applying CCS increases fossil energy consumption to achieve the desired decrease in GHG emissions intensity; however, this remains much higher than that of the conventional gasoline pathway.
(5) GHG emissions reduction effect of EV pathways will be lower when the vehicle cycle is included, because the GHG emissions from the production of an EV are higher great than ICEV. EVs charged by coal-power even show higher GHG emissions than those of gasoline ICEVs when both the vehicle-cycle and fuel cycle are included.

To promote alternative fuel/vehicle development and guarantee on-road vehicle energy demand, policymakers should establish near-, medium-, and long-term strategies and introduce practical policies to resolve the following key issues:

(i) To satisfy the increasing on-road vehicle energy demand, in the near-to-medium term, the main aim should be to promote the development of NG-based and coal-based fuels to partly substitute oil-derived fuels. In the longer term, the goal is to promote the development of EVs and R & D into CCS technology to affect a significant replacement of oil consumption and a substantial decrease in GHG emissions.
(ii) Combined technology-push and market-pull policies not only directly support the development of low-carbon fuel technology but also promote the large-scale industrial development and market penetration of low-carbon fuels. Corresponding recommendations include:

- Encourage conventional vehicles to use fossil energy-saving technologies, such as hybrid EVs.
- Promote the development of renewable energy, and accelerate R & D to commercialize CCS and other low-carbon electricity technologies.
- Accelerate the construction of transmission, distribution, and filling infrastructure for alternative liquid fuels.
- Support the demonstration of commercial operation of EVs to promote market expansion and the construction of charging infrastructure.
- Promote low-carbon liquid alternative fuels through the active development of the coal chemical industry, application of CCS technology as well as the development of second generation biofuels.
- Optimize the production process of vehicle (especially battery materials) to lower the GHG emissions during the manufacturing of vehicle.
- Accelerate the vehicle recycling industry, and promote the development of effective vehicle recycling techniques.

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Nomenclature

Symbol	
i	the type of primary fossil energy
j	the type of end-us energy
p	the number of sub-stage in the life cycle
q	the type of electricity pathway
η	energy efficiency
Variable	
$CH_{4,LC}$	life-cycle CH_4 emission intensities (g/MJ)
$CO_{2,LC}$	life-cycle CO_2 emission intensities (g/MJ)
E_{LC}	life-cycle primary fossil energy intensities (MJ/MJ)
EF_{LC}	life-cycle primary fossil energy consumption factors of end-use energy (MJ/MJ)
EN	end-us energy consumption factors (MJ/MJ)
FE	fuel/energy efficiency (MJ/km)
GHG_{LC}	life-cycle GHG emissions intensities (g $CO_{2,e}$/MJ)
$N_2O_{,LC}$	life-cycle N_2O emission intensities (g/MJ)
SH	proportions of end-use energy consumed in different sub-stages
R	the losses during electricity transmission
W	proportions of different electricity pathways
Abbreviations	
CC	carbon content
CCS	carbon capture and storage
$CO_{2,e}$	CO_2 equivalents
CAERC	China Automotive Energy Research Center, Tsinghua University
CNG	compressed natural gas
CtL	coal-to-liquid
DME	dimethyl ether
EV	electric vehicle
FOR	fuel oxidation rate
GHG	greenhouse gas
GREET	The Greenhouse gases, Regulated Emissions, and Energy use in Transportation model
GTL	gas-to-liquid
ICE	internal combustion engine
ICEV	internal combustion engine vehicle
ICtL	indirect coal-to-liquid
km	kilometer
LC	life-cycle
LCA	life-cycle analysis
LEM	Life cycle Emissions Model
LFP	$LiFePO_4$
LPG	liquefied petroleum gas
LNG	liquefied natural gas
NG	natural gas
NMC	$Li(NiCoMn)O_2$
PTW	pump-to-wheels

TLCAM	Tsinghua life-cycle analysis model
WTP	well-to-pump
WTW	well-to-well

Appendix A. Calculation of Life Cycle Factors for a Given End-Use Energy

A.1. Basic Definitions and Assumptions

The fossil energy intensity (EF_{LC}, MJ/MJ) and GHG emissions intensity (GHG_{LC}, g $CO_{2,e}$/MJ) for a given secondary energy (SE) were defined as the sum of all the primary fossil energy consumption (PFEC) and GHG emissions, respectively, across the entire fuel life cycle required to produce and use 1 MJ of the end-use energy.

As Table A1 shows, three fossil primary energies (PEs) were considered—coal, NG, and petroleum (i represents the type of PE)—alongside nine SEs (represented by j, x or z). For each SE, the LCA included m stages. For electricity generation (as denoted by n), four energy sources were considered: coal, NG, oil and "other".

Table A1. Energy types and production stages modeled.

No.	i (PE)	j, x or z (SE)	m (Stage Name)	n (Electricity Pathway)
1	Coal	Crude coal [a]	Feedstock production	Coal-based
2	NG	Crude NG [b]	Feedstock transportation	NG- based
3	Petroleum	Crude oil [b]	Fuel production	Oil-based
4	–	Coal [c]	Fuel transportation	Others
5	–	NG [c]	–	–
6		Diesel		
7		Gasoline		
8		Residual oil		
9		Electricity		

Note: [a] only recovered; [b] recovered and processed; [c] recovered, processed and transported.

A.2. Calculation of Fossil Energy Intensity

$EF_{LC,j}$ (the life cycle PFEC intensity of SE j) was calculated as the sum of all values of $EF_{LC,j,i}$ (the life cycle PE i intensity of SE j):

$$EF_{LC,j} = \sum_{i=1}^{3} EF_{LC,j,i}\ (j = 1, 2, \ldots, 9) \tag{A1}$$

$EF_{LC,j,i}$ was calculated using $EI_{m,j}$ (the total PE input during sub-stage m to produce 1 MJ of SE j), $SH_{m,j,z}$ (the share of SE z in the sub-stage m's total energy use per MJ of SE j produced) and $EF_{LC,z,i}$ (the life cycle PE i intensity of SE z):

$$\begin{aligned} EF_{LC,j,i} &= \sum_{m=1}^{4} \left(EI_{m,j} \sum_{z=1}^{9} (SH_{m,j,z} EF_{LC,z,i})\right) + \delta_{i,j} \\ \delta_{i,j} &= \begin{cases} 1 & when \quad (i,j) \in \{(1,1),(1,4),(2,2),(2,5),(3,3),(3,6),(3,7),(3,8) \quad \} \\ 0 & otherwise \end{cases} \end{aligned} \tag{A2}$$

Thus, $EF_{LC,j}$ could be calculated as:

$$\begin{cases} EF_{LC,j} = \sum_{i=1}^{3} \sum_{m=1}^{4} \left(EI_{m,j} \sum_{z=1}^{9} (SH_{m,j,z} EF_{LC,z,i})\right) + \gamma_j \\ \gamma_j = \begin{cases} 0 & for \quad j = 9 \\ 1 & otherwise \end{cases} \end{cases} \tag{A3}$$

For a non-electricity SE ($j = 1, 2, \ldots, 8$), EI was derived from sub-stage m's energy-transformation efficiency factor per MJ of SE j obtained ($\eta_{m,j}$) and the conversion factor from feedstock to fuel during the fuel production sub-stage for SE j (ξ_j; MJ/MJ):

$$EI_{1,j} = (1/\eta_{1,j} - 1)/\xi_j\ (j = 1, 2, \ldots, 8) \tag{A4}$$

$$EI_{2,j} = (1/\eta_{2,j} - 1)/\xi_j\ (j = 1, 2, \ldots, 8) \tag{A5}$$

$$EI_{3,j} = 1/\eta_{3,j} - 1 \ (j = 1, 2, \ldots, 8) \tag{A6}$$

$$EI_{4,j} = 1/\eta_{4,j} - 1 \ (j = 1, 2, \ldots, 8) \tag{A7}$$

For electricity ($j = 9$), the life cycle calculations were computed directly from sub-stage 3 using the nationally averaged supply mix to the grid:

$$EI_{m,9} = \begin{cases} \sum_{n=1}^{4} (RA_n/\eta_{3,9,n}/\eta_{4,9,n}) & for \quad m = 3 \\ 0 & otherwise \end{cases} \tag{A8}$$

where RA_n is the ratio of the nth electricity pathway to the total electricity generation; and $\eta_{3,9,n}$ and $\eta_{4,9,n}$ are the energy transformation efficiency factors for the electricity generation and the electricity transmission and distribution sub-stages for the nth electricity pathway, respectively.

Based on Equations (A1)–(A8), $\eta_{m,j}$, ξ_j and $SH_{m,j,z}$ were required for to calculate $EF_{LC,j,i}$ ($j = 1, 2, \ldots, 8$) and RA_n, $\eta_{3,9,n}$ and $\eta_{4,9,n}$ were necessary to calculate $EF_{LC,9,i}$. Because coal, NG, and crude oil occur as both PEs and SEs, Equations (A2)–(A7) were solved using an iterative computational method.

A.3. Calculation of GHG Emissions Intensities

A.3.1. General Description

The life cycle GHG emissions intensity of SE j ($GHG_{LC,j}$) consists of the three key types of GHG emissions (CO_2, CH_4 and N_2O). These types of GHG were converted into CO_2 equivalents ($CO_{2,e}$) according to their global warming potential [39,40]:

$$GHG_{LC,j} = CO_{2,LC,j} + 25CH_{4,LC,j} + 298N_2O_{LC,j} \tag{A9}$$

where $CO_{2,LC,j}$, $CH_{4,LC,j}$ and $N_2O_{LC,j}$ are the life cycle CO_2, CH_4 and N_2O emission intensities for SE j, respectively.

Similar to $EF_{LC,j,i}$, $GHG_{LC,j}$ was also calculated using an iterative method (which involved Equations (A12), (A15) and (A18)).

A.3.2. CO_2 Emissions

$CO_{2,LC,j}$ consists of two parts: emissions from upstream processes ($CO_{2,up,j}$, g/MJ) and direct emissions from the fuel-combustion process ($CO_{2,direct}$, g/MJ):

$$CO_{2,LC,j} = CO_{2,up,j} + CO_{2,direct,j} \tag{A10}$$

$$CO_{2,direct,j} = \frac{44}{12} CC_j FOR_j \tag{A11}$$

where CC_j is the carbon content of SE j (g/MJ); FOR_j is the fuel oxidation rate of SE j; and $\frac{44}{12}$ is the mass conversion factor between C and CO_2.

Upstream CO_2 emissions ($CO_{2,up,j}$) result from the direct CO_2 emissions during the production of SE x ($CO_{2,direct,x}$, g/MJ):

$$CO_{2,up,j} = \sum_{m=1}^{4} \sum_{x=1}^{9} (EI_{m,j} SH_{m,j,x} (CO_{2,direct,x} + CO_{2,up,x})) \tag{A12}$$

$CO_{2,direct,x}$ was then calculated using the following carbon-balance equation:

$$CO_{2,direct,x} = \frac{44}{12} CC_x FOR_x \tag{A13}$$

where CC_x is the carbon content of SE x (g/MJ); FOR_x is the fuel oxidation rate of SE x; and $\frac{44}{12}$ is the mass conversion rate between C and CO_2.

A.3.3. CH_4 Emissions

Similarly, $CH_{4,LC,j}$ also consists of an upstream part ($CH_{4,up,j}$) and a term that represents direct emissions from combustion ($CH_{4,direct,j}$):

$$CH_{4,LC,j} = CH_{4,up,j} + CH_{4,direct,j} \tag{A14}$$

$$CH_{4,up,j} = \sum_{m=1}^{4} \sum_{x=1}^{9} (EI_{m,j} SH_{m,j,x} (CH_{4,direct,m,x} + CH_{4,up,x})) + CH_{4,j,noncomb} \tag{A15}$$

$$CH_{4,j,noncomb} = CH_{4,j,resource}/\xi_j \tag{A16}$$

where $CH_{4,direct,m,x}$ is the direct CH_4 emissions during the sub-stage m (g/MJ) of the production of SE x; $CH_{4,j,noncomb}$ corresponds to the indirect CH_4 emissions from non-combustion sources, including spills and losses during NG extraction (g/MJ SE j); and $CH_{4,resource}$ corresponds to indirect CH_4 emissions during the resource extraction stage (g/MJ resource obtained).

A.3.4. N_2O Emissions

$N_2O_{LC,j}$ also consists of an upstream component ($N_2O_{up,j}$) and direct emissions released during combustion ($N_2O_{direct,j}$):

$$N_2O_{LC,j} = N_2O_{up,j} + N_2O_{direct,j} \tag{A17}$$

$$N_2O_{up,j} = \sum_{m=1}^{4}\sum_{x=1}^{9}(EI_{m,j}SH_{m,j,x}(N_2O_{direct,m,x} + N_2O_{up,x})) \tag{A18}$$

where $N_2O_{direct,m,x}$ is the direct N_2O emissions released for SE x during stage m (g/MJ).

A.4. Basic Calculation Data

This section presents the basic data used for the calculation of the life cycle fossil energy consumption factors (EF_{LC}) and GHG emissions factors (GHG_{LC}) for the nine end-use energies. Table A2 presents original, China-specific data for oil-, NG-, and coal-based fuels and electricity and includes energy conversion efficiencies, transport distances and the proportion of the different process fuels used in the various resource exploitation, transport, fuel processing and fuel production stages. The energy intensity and breakdown of fuels used by various transport modes are shown in Table A3. Direct and indirect GHG emissions released from the use of various energies in the Chinese context are shown in Table A4.

Table A2. Input data for LCA of different end-use energies.

Item	Description	Data Source
(1) Oil exploitation		
Crude oil import proportion	64.4% (2015)	[2]
Oil exploitation efficiency	93% (Domestic), 98% (Imported)	[7,34]
Fuel mix for oil exploitation	Refined NG (43%), crude oil (28%), electricity (14%), diesel (9%), raw coal (4%) residual oil (1%) and gasoline (1%)	[42]
(2) Oil transportation mode	Sea tanker: 60% (11,000 km); rail: 30% (942 km); pipeline: 78% (440 km); waterway: 10% (250 km)	[34,55]
(3) Oil refining		
Process fuel mix for oil refinery	Crude oil (79%), raw coal (6%), electricity (6%), refined NG (4%), clean coal (3%), residual oil (2%)	[42]
Gasoline production efficiency	89.1%	[34]
Diesel production efficiency	89.7%	[34]
Residual oil production efficiency	94%	[34]
(4) Gasoline, Diesel and Fuel oil transportation mode	Railway: 50% (900 km); pipeline: 15% (160 km); waterway: 10% (1200 km); road (short distance): 10% (50 km)	[34,55]
(5) NG exploitation and processing		
NG exploitation efficiency	96%	[34]
Fuel mix for NG exploitation	Refined NG (43%), crude oil (28%), electricity (14%), diesel (9%), raw coal (4%) residual oil (1%) and gasoline (1%)	[42]
Leakage in NG exploitation stage	0.34%	
NG processing efficiency	94%	[34]
Fuel mix for NG processing	Refined NG (99%) and electricity (1%)	[42]
(6) NG transportation mode	Pipeline: 100% (1500 km)	[55]
(7) Coal exploitation and processing		
Coal exploitation processing efficiency	95%	[34]
Fuel mix for coal exploitation and processing	Raw coal (73%), electricity (15%), clean coal (8%), diesel (3%) and refined NG (1%)	[42]
(8) Coal transportation mode	Railway: 49% (642 km); waterway: 26% (650 km); road (long distance): 30% (310 km) and road (short distance): 100% (50 km)	[42,55]
(9) Electricity supply mix	Coal (67.2%), NG (3%), residual oil (0.1%) and many other sources (29.7%)	[55]

Table A2. *Cont.*

Item	Description	Data Source
(10) Loss ratio during transmission and distribution	6.67%	[55]
(11) Electricity supply efficiencies	Coal-based (36.4%), oil-based (32.0%), NG-based (45.9%)	[44]

Note: The sum of the proportions of individual transport modes may exceed 100%. We also assume that these values will not change substantially over the medium-to-long term. Refinery gas is used during the refining of crude oil but is not included in our scope of end-use energies. We therefore assumed that this refining byproduct did not consume additional primary fossil energy but had a GHG emission intensity of 65 g/MJ.

Table A3. Energy intensity and fuel structure of various transport modes [34].

Transport Mode	Energy Intensity (kJ/ton km)	Fuel Types and Structures
Ocean	23	Fuel oil (100%)
Railway	68	Diesel (41%), electricity (59%)
Crude oil pipeline	300	Fuel oil (50%), electricity (50%)
NG pipeline	372	NG (90%), electricity (10%)
Water transport	148	Fuel oil (100%)
Short-distance highway	1362	Diesel (72%), gasoline (28%)
Long-distance highway	1200	Diesel (72%), gasoline (28%)

Table A4. Data related to direct and indirect GHG emissions for the Chinese context [39,45].

End-Use Energy	CC_j (g/MJ)	FOR_j (g/MJ)	$CH_{4,direct}$ (g/MJ)	$CH_{4,noncomb}$ (g/MJ)	N_2O_{direct} (g/MJ)
Raw coal	24.08	0.9	0.001	0.406	0.001
Raw NG	15.3	0.99	0.001	0.072	0.001
Crude oil	20	0.98	0.002	0.009	0
Clean coal	25.8	0.9	0.001	0.406	0.001
Processed NG	15.7	0.99	0.001	0.072	0.001
Diesel	20.2	0.98	0.004	0.009	0.002/0.028 [a]
Gasoline	18.9	0.98	0.08	0.009	0.002
Fuel oil	21.1	0.98	0.002	0.009	0
Electricity	–	–	–	0.98	–

Note: [a] The value of 0.002 is for vehicle but 0.028 for others.

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British Columbia LNG
Greenhouse Gas (GHG)
Life Cycle Analysis

Discussion Draft

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Prepared for:

BC Ministry of Environment,
Climate Action Secretariat

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CONTENTS

EXECUTIVE SUMMARY

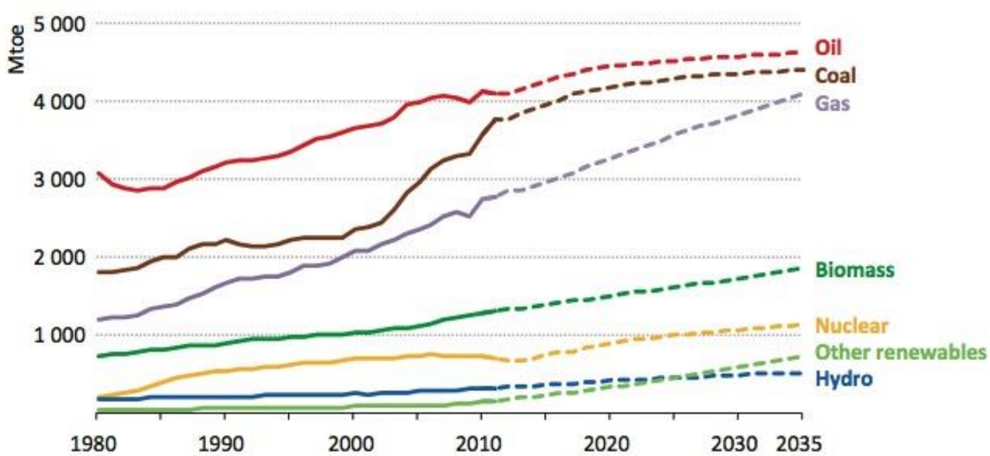
In September 2011, the BC Government released its *Canada Starts Here: The BC Jobs Plan*, which included a target to bring at least one liquefied natural gas (LNG) terminal online by 2015, with three LNG facilities in operation by the year 2020.

This project assesses the greenhouse gas (GHG) emissions impact of British Columbia's natural gas export value chain from the wellhead to various consumer markets overseas, assuming BC begins shipping LNG product within the next three years (by 2017). GLOBE's research is based on available international energy reports and public data supplied by the BC Government, Statistics Canada, and Environment Canada, as well as GHG life cycle models developed by Natural Resources Canada (GHGenius Model) and Argonne Labs in the United States (GREET Model).

The assessment involved an examination of the country partners and markets that are associated with potential LNG infrastructure projects in BC, with the aim to determine whether the export of LNG, originating in BC and exported globally, will have a positive or negative full life cycle impact on overall global GHG emissions.

Global Energy Demand and Supply

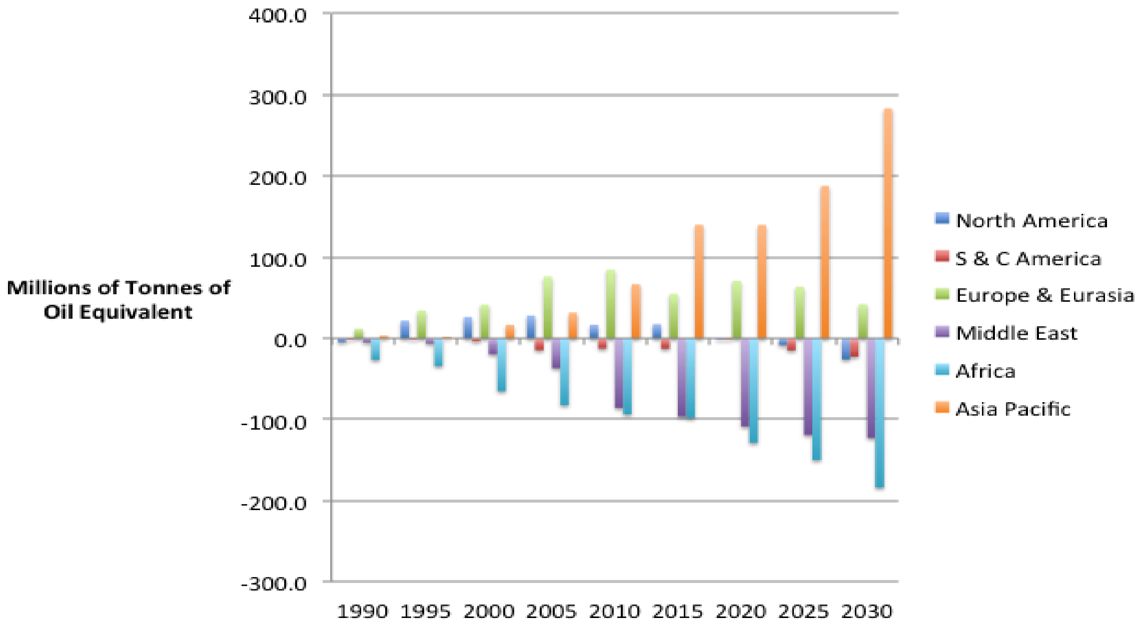
The future markets for natural gas in Asia, as reported by the International Energy Agency (IEA) and the United States Energy Information Office, forecast highly bullish natural gas markets over the next two decades, with the likelihood that much of this natural gas will be used to replace coal-fired power generation. The IEA, based on its *New Policies Scenario*, projects that there will be a growing global demand for natural gas, while the demand for other fossil fuels (in particular coal and oil) and nuclear power levels off by 2035.



Source: International Energy Agency, World Energy Outlook, 2013

Figure: World primary energy demand by fuel in the *New Policies Scenario*.

The Asia Pacific region is short in the supply of natural gas relative to demand (as illustrated in the figure below). While GLOBE cannot definitively conclude that all natural gas purchases in Asia will be used to replace coal, predictions by reputable sources including the IEA, suggest that this will largely be the case.



Source: BP Global Energy Projections

Figure: Global natural gas demand minus supply projections.

BC's Natural Gas Value Chain GHG Emissions

GLOBE estimated the full life cycle GHG emissions for BC's natural gas overseas export value chain. This value chain includes natural gas production at the wellhead; processing (treatment and compression); distribution to LNG facilities (transportation by pipeline); liquefaction at LNG facilities; ocean transportation; and consumption (combustion) by end users.

Two emissions scenarios were prepared: (1) a standard or "traditional" LNG plant with upstream emissions based on the GHGenius model; and (2) a "clean" LNG plant that utilizes renewable electricity, state-of-the-art practices, and carbon capture and storage (CCS) as part of its facility.

While proponents have yet to develop LNG projects along the BC coastline, the proposed LNG plants can achieve very significant efficiencies for reduced GHG emissions due to the use of electric drive compressors that, in turn, run on a combination of new renewable power, existing BC grid hydro electricity, and efficient combined-cycle natural gas generators.

There is also the potential for using CCS technologies. These technologies do not necessarily involve the more traditional practice of storing CO_2 in rock caverns or depleted gas and/or oil wells, but may also include technologies and/or processes that allow for CO_2 to be converted into useful products such as biofuel, biochemicals, bioplastics, and building materials. There are a number of CCS technology options that can be explored in British Columbia for lowering overall upstream GHG emissions.

For scenario one, the "traditional" LNG plant scenario, the GHGenius model provided a well-to-waterline GHG emissions ratio of approximately 0.75 tonnes of CO_2e per tonne of LNG (tCO2e / tLNG) produced, assuming that no CCS technologies are employed. For scenario two, the "clean" LNG plant scenario, GLOBE Advisors assumed that the proposed LNG plants in BC will be developed in-line with current "best-in-class" LNG projects, as well as CCS technology, and as such, could produce well-to-waterline GHG emissions of approximately 0.38 tCO2e / tLNG, equal to a 50 per cent reduction over the "traditional" plant scenario.

Average LNG tanker transportation emissions from BC to Asian markets amount to an estimated additional 0.08 tCO2e / tLNG. Consequently, delivering BC's LNG product to customers overseas results in approximately 0.83 tCO2e / tLNG produced under the "traditional" LNG plant scenario and 0.46 tCO2e / tLNG from the "clean" LNG plant scenario.

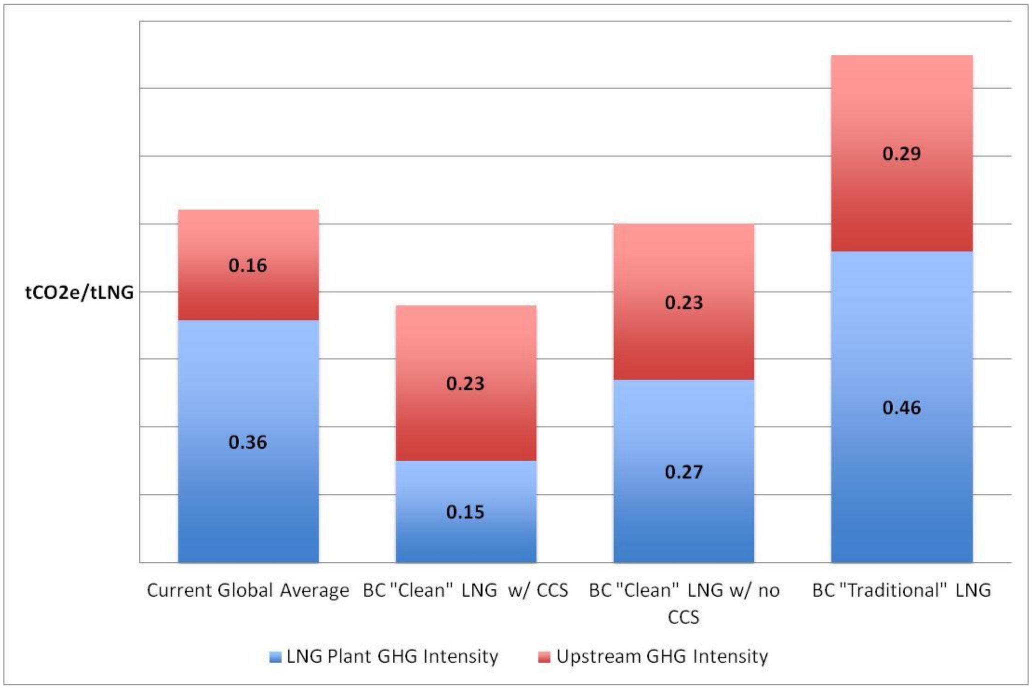
The wellhead to customer GHG emission factors are a relatively small components of the full life cycle of natural gas when combustion factors are included based on the customer burning natural gas for producing electrical power. As such, the full life cycle GHG emissions from wellhead to overseas customer ranges from 2.95 tonnes of CO_2e per tonne of LNG produced (scenario 1) to 3.32 (scenario 2), as shown in the table below.

Table: Full life cycle GHG emissions for the overseas export and consumption of BC natural gas to Asian markets for both "traditional" and "clean" LNG plant operations.

	"Traditional" LNG Plant GHG Emission Rate (tCO_2e / tLNG)	**"Clean" LNG Plant GHG Emission Rate** (tCO_2e / tLNG)
Exploration & Wellhead		
Fuel distribution and storage	0.07	0.06
Fuel production	0.07	0.06
Feedstock recovery	0.09	0.08
Gas leaks and flares	0.07	0.04
Subtotal	**0.29**	**0.23**
LNG Plant		
CO_2, H_2S removed from NG	0.12	0.01
Liquefaction at LNG Plants	0.33	0.14
Subtotal	**0.46**	**0.15**
Well-to-Water Upstream with CCS		**0.38**
Well-to-Water with no CCS	**0.75**	**0.50**
Tanker Emissions	**0.08**	**0.08**
Customer Combustion Emissions	2.49	2.49
Total Life Cycle Emissions with CCS		**2.95**
Total Life Cycle Emissions without CCS	**3.32**	**3.07**

LNG plant emissions of 0.15 tonnes of GHG per tonne of LNG produced (or a 58 per cent reduction from a “traditional” LNG plant powered by fossil fuels) is both possible and plausible, as the LNG plants in BC can employ near-zero emission clean electricity to power the compressors.

The figure below compares the global average well-to-waterline GHG emissions for various LNG plants around the world, equal to 0.52 tCO2e / tLNG, to hypothetical LNG plants in British Columbia under three scenarios: (a) the BC “clean” LNG plant emissions factor of 0.38 tCO2e / tLNG with the application of CCS technologies ; (b) the BC “clean” LNG plant factor with no CCS that results in plant and upstream emissions of 0.50 tCO2e / tLNG; and (c) the “traditional” LNG plant well-to-waterline emissions factor of 0.75 tCO2e / tLNG based on the GHGenius model.



Source: GLOBE Advisors and Australia Pacific LNG Project Volume Greenhouse Gas Assessment by LNG Facility (Worley Parsons)

Figure: Global average well-to-waterline GHG emissions intensity compared to three BC LNG plant well-to-waterline GHG emissions scenarios.

As illustrated in the figure above, the BC “traditional” LNG plant factor, based on GHGenius, results in emissions in excess of the current global average while the BC “clean” LNG plant factor with CCS would result in significantly less GHG emissions.

Impact of BC's LNG Exports on Global GHG Emissions

A fundamental question is whether or not natural gas being exported from BC will be consumed as an alternative to other fuel sources, and in particular, as a replacement for coal. When natural gas is used to replace coal and/or natural gas being sourced from other locations with higher life cycle GHG emissions, it has an overall positive impact on reducing global GHG emissions and local air pollutants.

Natural gas is a particularly attractive fuel for countries and regions that are urbanizing and seeking to satisfy rapid growth in energy demand, such as China and India. These countries will largely determine the extent to which natural gas use expands over the next 25 years.[1] Research suggests that natural gas imported by Asian economies is expected to largely replace existing or planned thermal coal power and, hence, will provide an overall reduction in CO_2 equivalent emissions due to the lower combustion emissions of natural gas over coal.

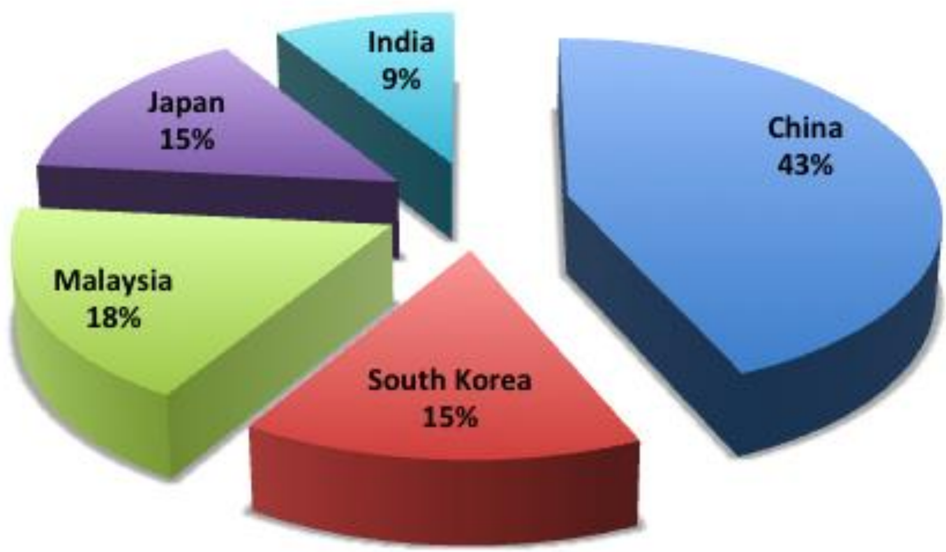
In order to determine the overall impact on global GHG emissions from the export of BC's natural gas to Asia, an examination of energy consumption trends for each market was carried out. This assessment provided the conclusion that natural gas exports from BC would, for the most part, replace coal and to a lesser degree, natural gas coming from other sources, with the exception of Malaysia where natural gas would most likely replace diesel used for power generation (see table below).

Table: Impact of BC's natural gas exports on energy consumption in select Asian markets.

Country	Impact on Energy Consumption
China	Mixture of replacing coal and natural gas from other sources
Japan	Mixture of replacing coal and LNG from other sources
South Korea	Mixture of replacing coal and LNG from other sources
India	Mixture of replacing coal and natural gas from other sources
Malaysia	Replace diesel power

[1] See: http://www.iea.org/newsroomandevents/pressreleases/2011/june/name,20306,en.html

This assessment was further linked to the projected distribution of BC's LNG exports to economies in Asia based on projected Asian market demand scenarios by the IEA, as well as the planned LNG infrastructure project investments in BC (see figure below). It was assumed that by 2021, 67 per cent of the proposed LNG projects in BC would be operational, producing approximately 88 million metric tonnes per annum (mmtpa) of LNG.



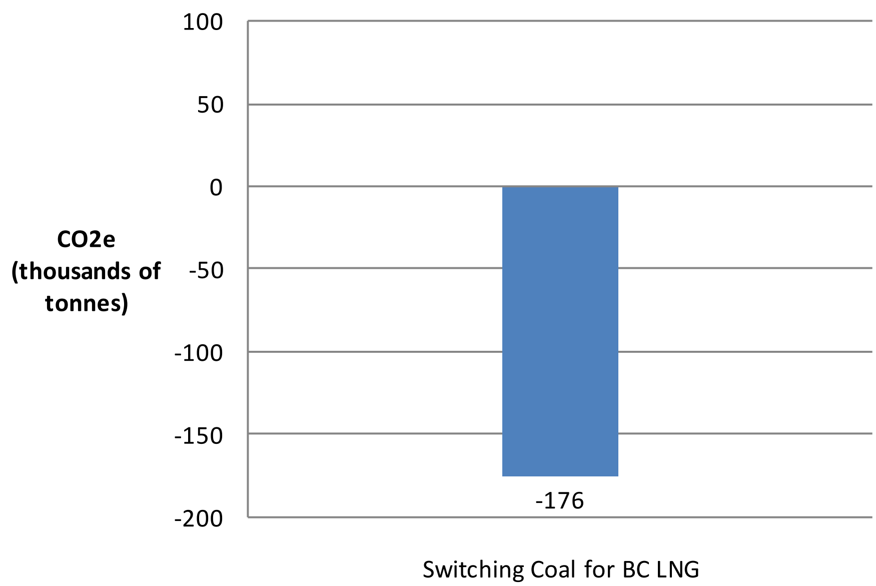
Source: IEA World Outlook 2013 and various BC LNG infrastructure websites

Figure: Estimated distribution of BC's LNG exports to countries in Asia.

Natural Gas Switching Scenarios

GLOBE Advisors examined the impact on global GHG emissions of two scenarios where natural gas from BC is exported as LNG to Asian markets for consumption.

The "*Full Coal Switching*" scenario looks at the GHG emissions impact of having natural gas from BC completely replace coal-powered electricity production and/or serve as an alternative to the construction of new coal-fired power facilities. The GHG emissions avoided by Asian markets consuming 88 mmtpa of LNG produced in BC could amount to an annual reduction of 176 million tonnes of CO_2e over the GHG emissions from the same amount of energy produced by the combustion of thermal coal.



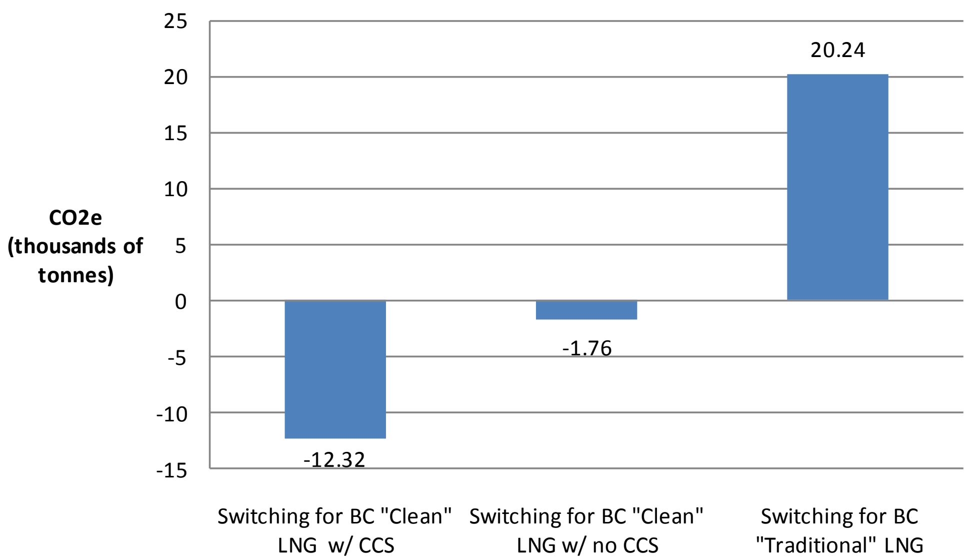
Source: GLOBE Advisors

Figure: Annual GHG emissions impact of having BC natural gas completely replace coal-powered electricity production under the *Full Coal Switching* scenario (assuming LNG production of 88 mmtpa).

The "*Full Natural Gas Switching*" scenario looked at the impact on global GHG emissions of having natural gas exported from BC to Asian markets replace natural gas coming from other global suppliers where the global LNG average well-to-waterline GHG emissions was compared to BC's hypothetical LNG well-to-waterline GHG emissions.

In the *Full Natural Gas* switching scenario, achieving the "clean" LNG plant well-to-waterline factor of 0.38 tCO_2e / tLNG produced could result in a fairly significant reduction of global GHG emissions – in the range of 12.4 million tonnes of CO_2e per year (based on BC's estimated annual production level of 88 mmtpa by 2021). If BC's LNG plants apply renewable energy and upstream best practices but no CCS technology, the reduction in global GHG emissions would be 1.8 million tonnes of CO_2e per year for the production of 88 mmtpa of LNG in BC. Nonetheless, even in the absence of CCS, lower global GHG emissions occur when "clean" BC natural gas replaces LNG produced elsewhere.

The net CO_2e savings based on BC natural gas replacing natural gas sourced from global suppliers (using the global average) is shown in the figure below.[2] Note that where BC's natural gas under the "traditional" LNG plant scenario replaces natural gas with the global average GHG emissions factor, a net increase in global CO_2e emissions occurs.



Source: GLOBE Advisors

Figure: Annual GHG emissions impact of having BC natural gas replace natural gas supplied by natural gas with the global average GHG emissions footprint under the *Full Natural Gas Switching* scenario (assuming LNG production of 88 mmtpa).

[2] **Note to reader:** Marine transportation GHG emissions are not included in this comparison as these vary based on the consumer market and global supplier. However, the difference in transportation emissions between global suppliers is relatively small, particularly when compared with the full life cycle emissions.

Conclusions

Based on a review of secondary sources and global trends in energy demand and supply, GLOBE Advisors believes that the most realistic outcome for natural gas exported from BC to Asian markets will be a combination of switching out / replacing both thermal coal *and* natural gas product from other global suppliers (with the exception of Malaysia where it may go primarily to replacing diesel).

The scenarios discussed in this report provide three examples where, on a full life cycle basis, there is a net reduction of global GHG emissions from the export of BC's natural gas to overseas markets in Asia. These scenarios include the replacement / substitution of thermal coal in Asian markets and the replacement or substitution of LNG coming from other global suppliers (assuming the global average for life cycle GHG emissions) with LNG produced in BC under the two "clean" LNG plant examples. Our analysis shows that "clean" natural gas from BC could result in significantly reduced global GHG emissions depending on which scenario is achieved.

In the case where it acts as a substitute for natural gas from other global suppliers, it is particularly important to consider whether or not the upstream life cycle GHG emissions for the supply of natural gas coming from other global markets (i.e., shale and coal bed plays in Russia, China, Australia, and elsewhere) and, in some cases the related LNG plant facilities, is more or less carbon intensive than the natural gas being exported from British Columbia. This is a difficult question to answer, as BC has not yet built LNG plants and the GHG emissions described in this report are only hypothetical at this stage.

At the end of the day, the total net benefit that will come from exporting BC's natural gas to Asian markets in terms of its ability to reduce overall global GHG emissions will depend largely on how much coal is displaced.

Where it serves as a substitute for natural gas from other sources, keeping the BC well-to-waterline factor below the global average (currently estimated to be 0.52 tCO_2e / tLNG) would result in a net benefit in terms of reducing global GHG emissions. Achieving the well-to-waterline GHG emissions factor of 0.38 tCO_2e / tLNG could result in a significant reduction of global GHG emissions.

British Columbia has an opportunity to produce some of the cleanest LNG in the world, in part by reducing fugitive emissions and flaring, but particularly by encouraging action during LNG production at the plant. British Columbia can achieve LNG plant production GHG emission factors that are better than the current Canadian "industry standard" and global average by applying renewable power, modern and efficient technology such as electric drive compressors, and CCS solutions where feasible.

INTRODUCTION

This project assesses the greenhouse gas (GHG) emissions impact of British Columbia's natural gas export value chain from the wellhead to various consumer markets overseas. The key question is "*will the development and export of LNG, originating in BC and exported globally, have a positive or negative impact on overall global GHG emissions?*"

Many believe that natural gas is a bridge fuel to the low carbon economy, as it burns cleaner than other fossil fuels. Some, however, challenge this view. They argue that while natural gas burns cleaner at the consumer stage, it can produce considerable GHG emissions at the exploration and production stage, mostly due to fugitive gases, which may be under-reported. Their position is that if these fugitive gases were counted accurately, natural gas could produce similar or even higher GHG emissions than coal, diesel, and petrol.

Producing LNG for export involves the actual liquefaction facility, as well as the full upstream chain of production that includes gas extraction, processing, and transportation. The LNG producers will source some of their gas from unconventional shale deposits, some of which have a higher carbon dioxide content than conventional deposits. This shale gas would be piped across the province, and liquefied at different locations, which, without mitigation measures, may increase the carbon footprint of the final product.

To what extent will BC's LNG be replacing higher or lower GHG intensive fuels? To get at the crux of this question, a detailed examination of the end user of potential natural gas exports from British Columbia is required through the examination of the country partners and markets that are associated with potential LNG infrastructure projects in BC.

In this research, GLOBE examines the realities of BC's natural gas GHG emissions based on available data produced by BC Stats, Statistics Canada, and Environment Canada, as well as GHG life cycle models developed by Natural Resources Canada and Argonne Labs in the United States. GLOBE also examined the potential GHG life cycle of natural gas in British Columbia from the wellhead to the overseas consumer, assuming BC begins shipping LNG product within the next five year timeframe.

GLOBE also examined future markets for natural gas in Asia as reported by the International Energy Agency (IEA) and the United States Energy Information Office. These reports strongly forecast highly bullish natural gas markets over the next two decades and the likelihood that much of this natural gas purchases will replace coal power. GLOBE cannot definitively conclude that all Asian natural gas purchases will replace coal, although this occurrence should be mostly accurate. Subsequently, the analysis puts forward scenarios where varying amounts of coal are being replaced by natural gas such as 25 percent, 50 percent, and 100 percent.

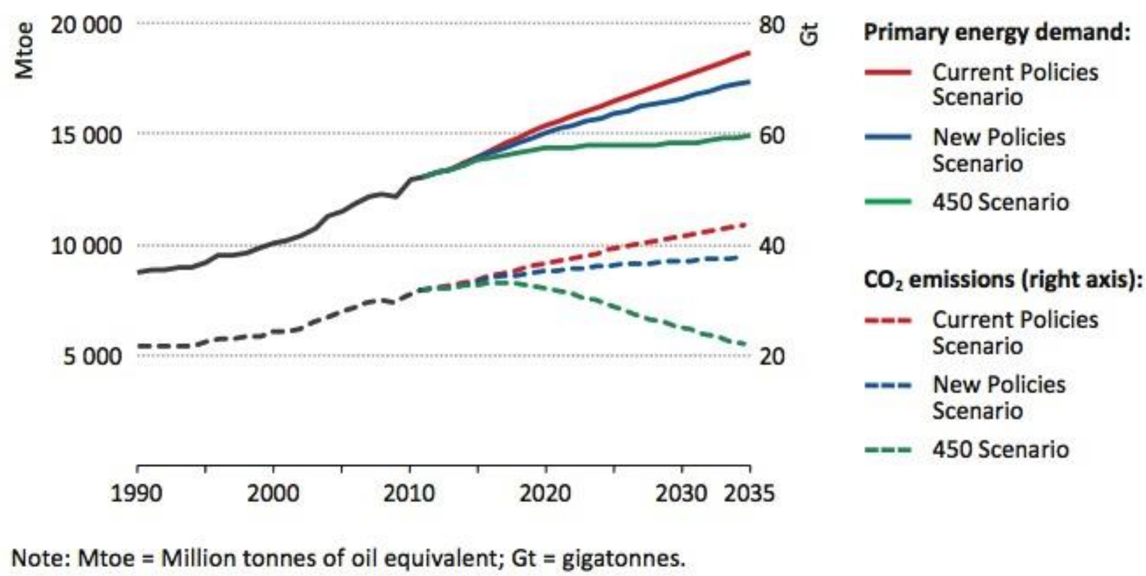
This report is not a detailed engineering study but rather, is meant to serve as a document to help inform policy makers by putting the lifecycle GHG emissions for BC's LNG production into a global perspective. Please note that GLOBE uses the term GHG emissions to include CO_2 equivalent emissions. These two terms GHG and CO_2e are used interchangeably in this document.

PART 1: GLOBAL ENERGY DEMAND, SUPPLY & GHG EMISSION SCENARIOS

This section provides an overview based on existing sources for global medium and long-term energy and greenhouse gas (GHG) emission scenarios where BC is not exporting LNG to overseas markets.

Global Market for Energy

The International Energy Agency's 2013 global forecasts for energy demand and associated CO2 emissions are illustrated in Figure 1 below.



Source: International Energy Agency, World Energy Outlook, 2013

Figure 1: World primary energy demand and related CO2 emissions by scenario

This forecast provides scenarios for the continuation of current energy policies (*Current Policy Scenario*), *New Policies Scenario* where governments are committed to increased energy efficiency and lower GHG emissions, and the *450 Scenario*, which is a "scenario presented in the World Energy Outlook that sets out an energy pathway consistent with the goal of limiting the global increase in temperature to 2 degrees Celsius by limiting concentration of greenhouse gases in the atmosphere to around 450 parts per million of CO_2".[3]

[3] See: http://www.iea.org/publications/scenariosandprojections/

More specifically, the global forecast for energy-related CO_2 emissions is shown by fuel type in Figure 2 below.

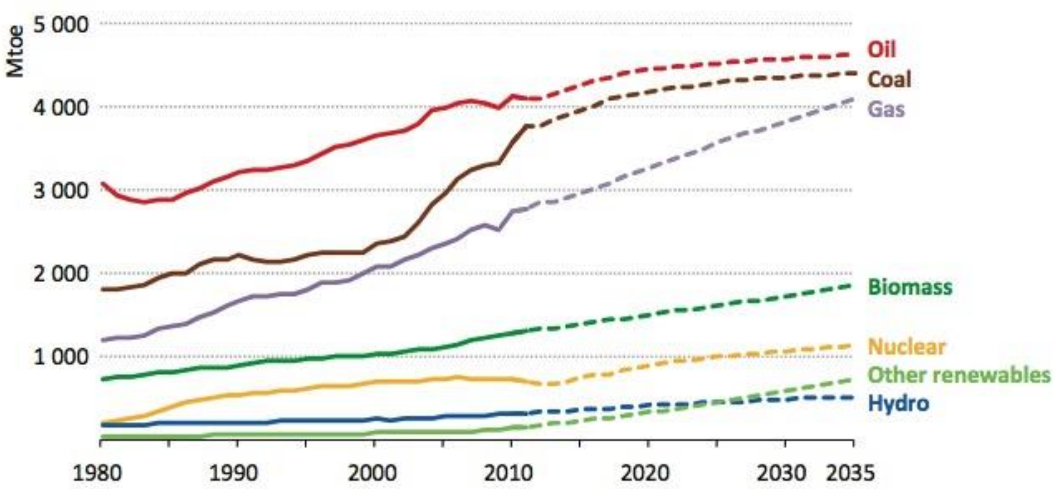
			New Policies Scenario		Current Policies Scenario		450 Scenario	
	2000	2011	2020	2035	2020	2035	2020	2035
Coal	2 357	3 773	4 202	4 428	4 483	5 435	3 715	2 533
Oil	3 664	4 108	4 470	4 661	4 546	5 094	4 264	3 577
Gas	2 073	2 787	3 273	4 119	3 335	4 369	3 148	3 357
Nuclear	676	674	886	1 119	866	1 020	924	1 521
Hydro	225	300	392	501	379	471	401	550
Bioenergy*	1 016	1 300	1 493	1 847	1 472	1 729	1 522	2 205
Other renewables	60	127	309	711	278	528	342	1 164
Total (Mtoe)	**10 071**	**13 070**	**15 025**	**17 387**	**15 359**	**18 646**	**14 316**	**14 908**
Fossil fuel share	*80%*	*82%*	*80%*	*76%*	*80%*	*80%*	*78%*	*64%*
*Non-OECD share***	*45%*	*57%*	*61%*	*66%*	*61%*	*66%*	*60%*	*64%*
CO_2 emissions (Gt)	**23.7**	**31.2**	**34.6**	**37.2**	**36.1**	**43.1**	**31.7**	**21.6**

* Includes traditional and modern biomass uses. ** Excludes international bunkers.

Source: International Energy Agency, World Energy Outlook, 2013

Figure 2: World primary energy demand and energy-related CO2 emissions by fuel type and scenario

This forecast is shown graphically for the *New Policy Scenario* in Figure 3. Note that globally, the IEA predicts under its *New Policies Scenario* that there will be a growing demand for natural gas, while the demand for other fossil fuels and nuclear power begins to level off by 2035. In the IEA's *450 Scenario* and its *Golden Age of Gas Scenario*[4], natural gas demand actually pushes the share of coal in the energy mix into decline and overtakes it by 2030.



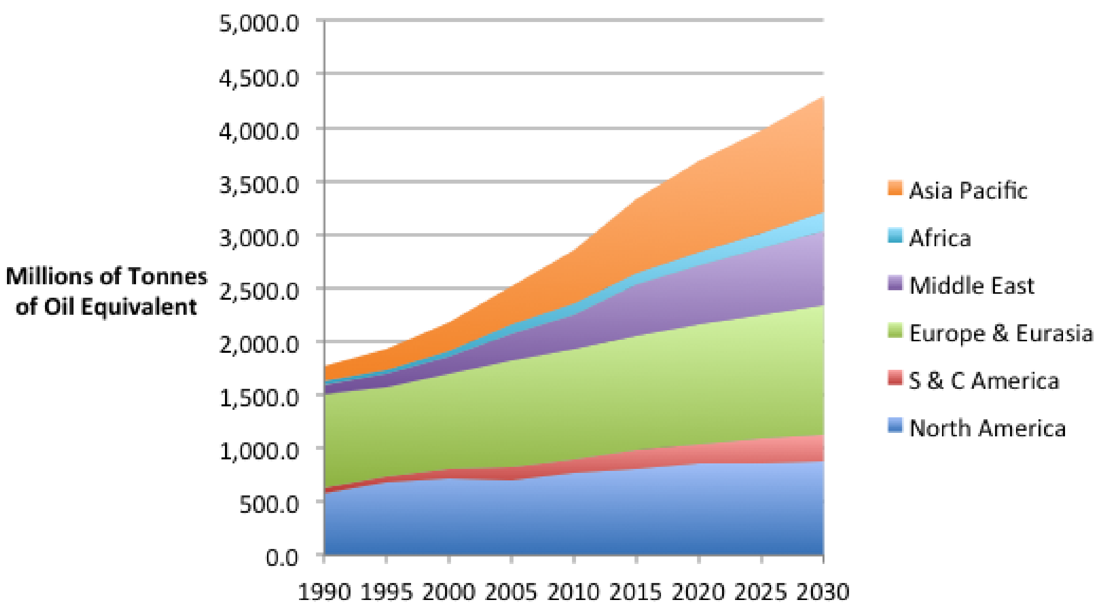
Source: International Energy Agency, World Energy Outlook, 2013

Figure 3: World primary energy demand by fuel in the *New Policies Scenario*.

4 See: http://www.worldenergyoutlook.org/media/weowebsite/2011/WEO2011_GAG_FactSheet.pdf

Global Market Demand for Natural Gas

Demand for liquefied natural gas (LNG) is heating up around the world, with demand projections to 2030 showing exponential growth – especially in Asian economies (Figure 4). These economies, however, will not be producing sufficient natural gas to meet their demand, as is illustrated in the following section on global supply.



Source: BP Global Energy Projections

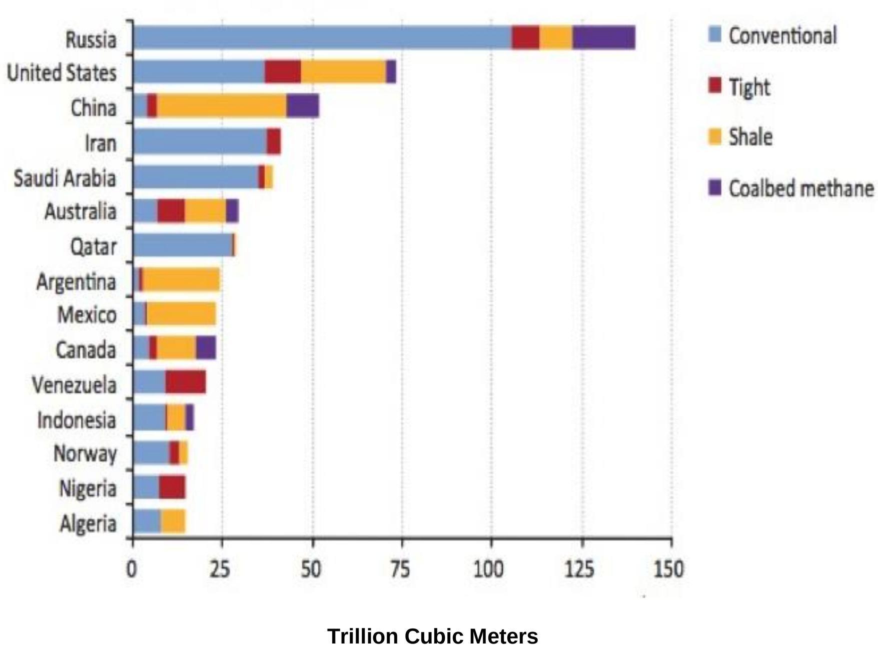
Figure 4: Natural Gas Demand Projections

Global Supply of Natural Gas & LNG Infrastructure

In its *Special Report on Unconventional Gas, Golden Rules for a Golden Age of Gas,* the International Energy Agency (IEA) concluded that "*natural gas is poised to enter a golden age, but will do so only if a significant proportion of the world's vast resources of unconventional gas - shale gas, tight gas, and coalbed methane - can be developed profitably and in an environmentally acceptable manner*….Yet a bright future for unconventional gas is far from assured: numerous hurdles need to be overcome, not least the social and environmental concerns associated with its extraction."[5]

Producing unconventional gas is an intensive industrial process, generally imposing a larger environmental footprint than conventional gas development. More wells are often needed and techniques such as hydraulic fracturing are usually required to boost the flow of gas from the well. The scale of development can have major implications for local communities, land use, and water resources. Serious hazards, including the potential for air pollution and for contamination of surface and groundwater, must be successfully addressed. Greenhouse gas emissions must be minimized, both at the point of production, and throughout the entire natural gas supply chain. Improperly addressed, these concerns threaten to curb, if not halt, the development of unconventional resources.

The IEA report discussed natural gas supply opportunities for several regions around the globe. These are illustrated in Figure 5. The top five overall natural gas supply countries include Russia, the United States, China, Iran, and Saudi Arabia. However, China, the United States, Argentina, Mexico, and Australia have the largest potential supplies of shale gas and tight gas. Canada is positioned slightly behind Australia in shale and tight gas supplies.

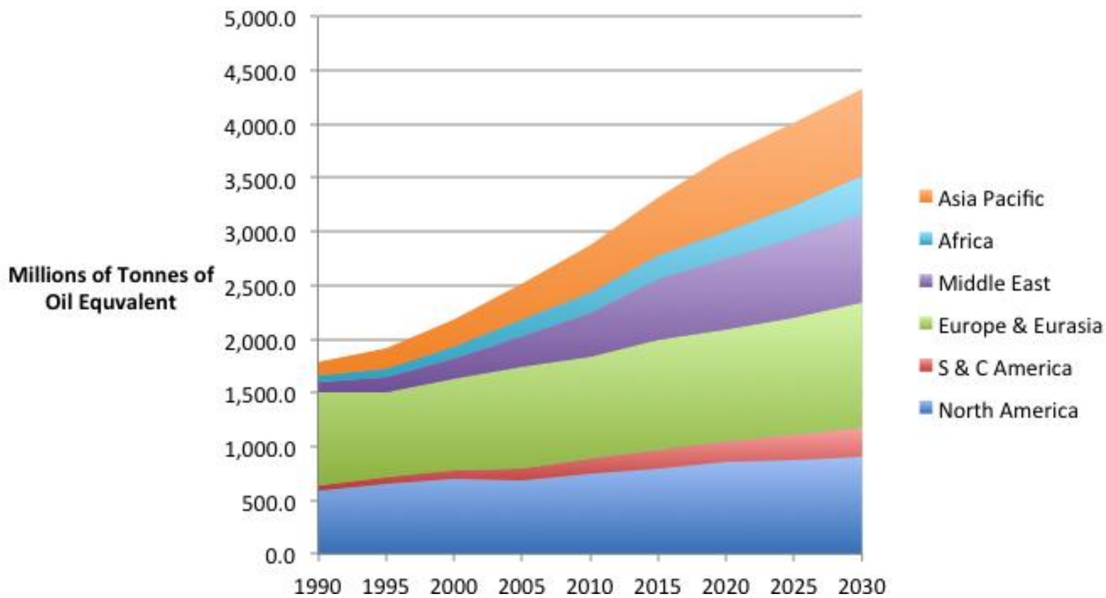


Source: International Energy Agency, Golden Rules for a Golden Age of Gas

Figure 5: Remaining recoverable natural gas reserves in the top 15 countries (end-2011)

[5] International Energy Agency in a Special Report on Unconventional Gas, *Golden Rules for a Golden Age of Gas*.

LNG exporters in Australia, Russia, Malaysia, and Qatar have been quick to respond to the demand for natural gas Asia. The chart in Figure 6 below shows natural gas supply projections by major geographic region to 2030. This supply is forecast to grow significantly in all regions of the globe. As such, competitors are already on track to develop much of the necessary infrastructure to fulfill the needs of this expanding market and are responding by locking in multiyear supply contracts.



Source: BP Global Energy Projections

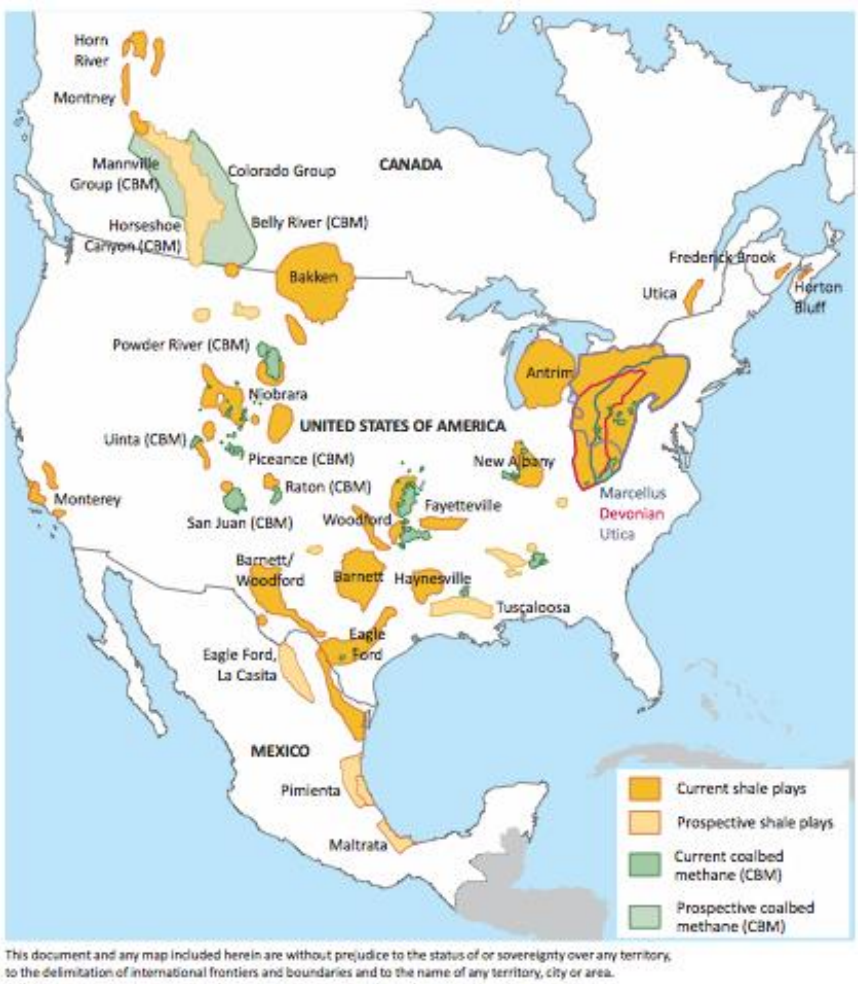
Figure 6: Natural gas supply projections to 2030.

North American Supply of Unconventional Natural Gas

The Canadian Association of Petroleum Producers (CAPP) have forecast that the majority of future natural gas production in Canada will be unconventional gas including tight gas, shale gas, and coalbed methane. In fact, CAPP is forecasting that in Western Canada, including BC, conventional gas will decline and production of unconventional gas will significantly grow. In short, in most non-OPEC countries, the future of gas is in the unconventional play. Therefore, a brief discussion of unconventional reserves by global region follows below.

The IEA has published in its Golden Age of Gas report a map of the recoverable shale gas reserves for North America (see Figure 7). Significant supplies of current and prospective shale plays are located in the Peace River Region of Alberta and British Columbia, the Bakken Region in the Dakotas, Mid-Eastern United States, and in Texas. The Mexican shale gas plays are located in that country's East Coast. In BC, the Horn River and Montney are the dominant unconventional natural gas plays, which are of the shale gas variety.

The IEA reports that for the United States only 65% of tight gas, 45% of coalbed methane and 40% of shale gas resources are accessible.

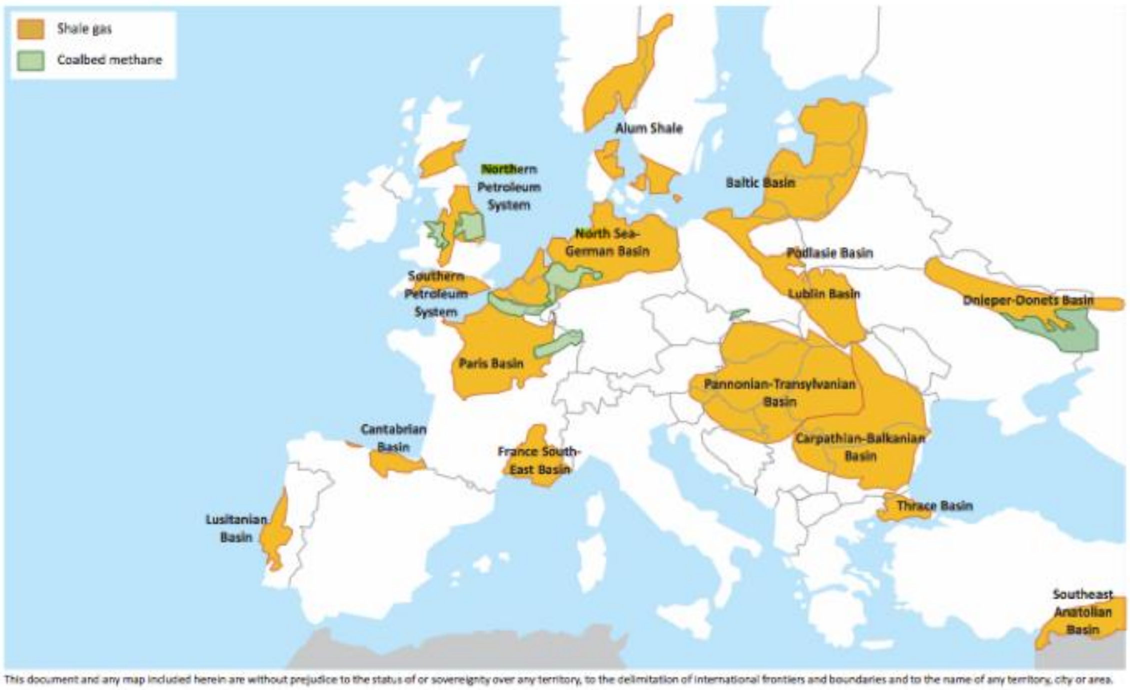


Source: International Energy Agency, 2013

Figure 7: Major unconventional natural gas resources in North America.

European Supply of Unconventional Natural Gas

The IEA has published in its Golden Age of Gas report a map of the recoverable shale gas reserves in Europe (see Figure 8). Unconventional supplies of natural gas in Europe are of interest to BC as these supplies may compete with BC as a supplier to Asian markets.

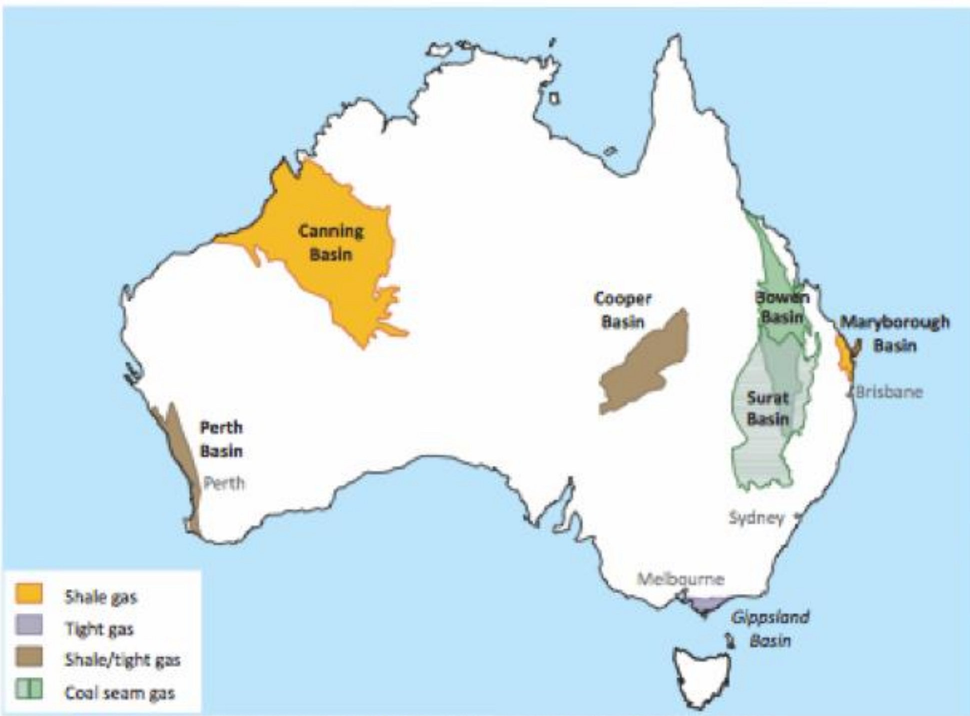


Source: International Energy Agency, 2013

Figure 8: Major unconventional natural gas resources in Europe.

Australian Supply of Unconventional Natural Gas

The IEA has published in its Golden Age of Gas report a map of the recoverable shale gas reserves for Australia (see Figure 9). In Australia, only 40% of coalbed methane and none of the shale gas resources are assumed to be accessible. Development of both types of resources has already become controversial in Australia. About 5 bcm of coalbed methane was produced in Australia in 2010 and there are three large-scale projects underway to build LNG plants fed by coalbed methane. The restriction to 40% of available resources essentially amounts to no new projects being authorized beyond those announced.



This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: International Energy Agency, 2013

Figure 9: Major unconventional natural gas resources in Australia.

Chinese Supply of Unconventional Natural Gas

The IEA has published in its Golden Age of Gas report a map of the recoverable shale gas reserves for China (see Figure 10). For China, the IEA report that only 40% of the coalbed methane and 20% of the shale gas resources are assumed to be accessible. Public acceptance is likely to be a lesser influence in China than in other countries.

This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: International Energy Agency, 2013

Figure 10: Major unconventional natural gas resources in China.

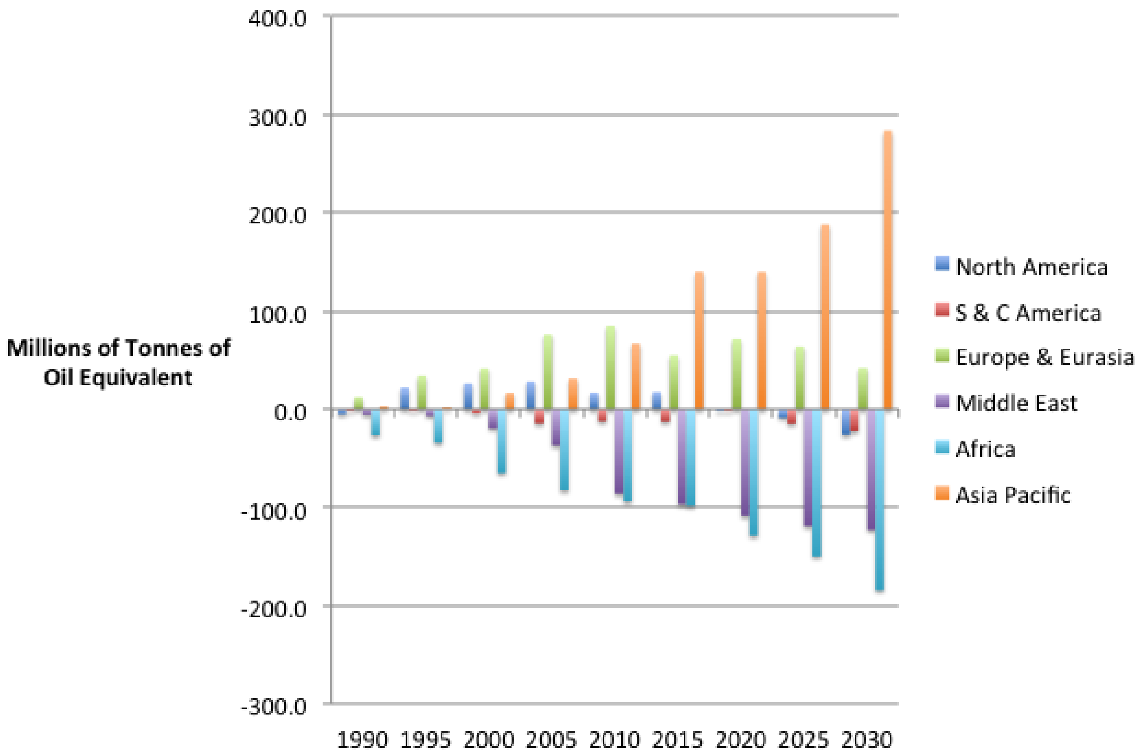
For the rest of the world, the IEA reports that no new unconventional gas resources are assumed to be developed (for which GLOBE uses per centages of about half of those in the United States to reflect similar dynamics, but the smaller part of the resources so far developed).

While Russia has significant conventional supplies of natural gas, unconventional resources are not expected to play a significant role. It is fair, however, to assume that natural gas from Russia will be in direct competition with LNG being exported from BC to Asian markets.

One issue is whether or not the shale and coalbed plays in Asia and Australia are more GHG intensive than the activities in British Columbia. Longer pipeline distances to the LNG plant will of result in somewhat higher fugitive emissions. Similarly, older LNG plants will likely be less efficient and emit higher amounts of GHG emissions than more modern, process-efficient or “cleaner” plants.

Global Demand for Natural Gas Relative to Supply

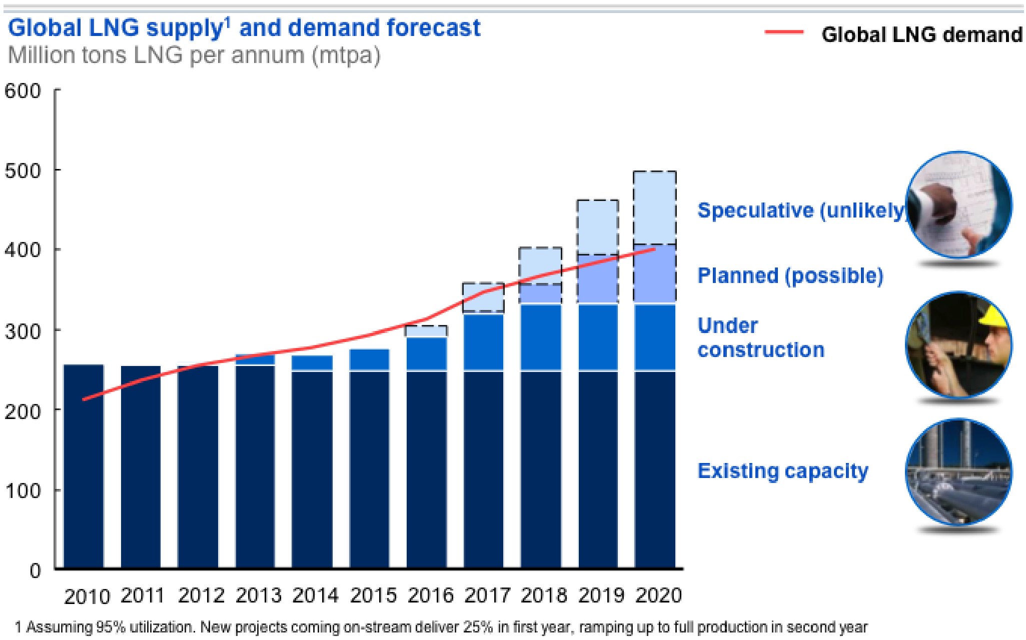
North America, including BC, has substantial excess supply of natural gas relative to its demand and the Asia Pacific Region is short of supply relative to demand (as illustrated in Figure 11). Taking a supply / demand view of the Asia Pacific region through 2030, there is still a projected gap in supply to meet projected demand, especially when taking into account the huge growth expected in China and India.



Source: BP Global Energy Projections

Figure 11: Natural Gas Demand Minus Supply Projections

Figure 12 illustrates the global LNG supply and demand forecast. Global demand for LNG is expected to be in the range of 400 million tons per annum (MMTPA) by 2020.



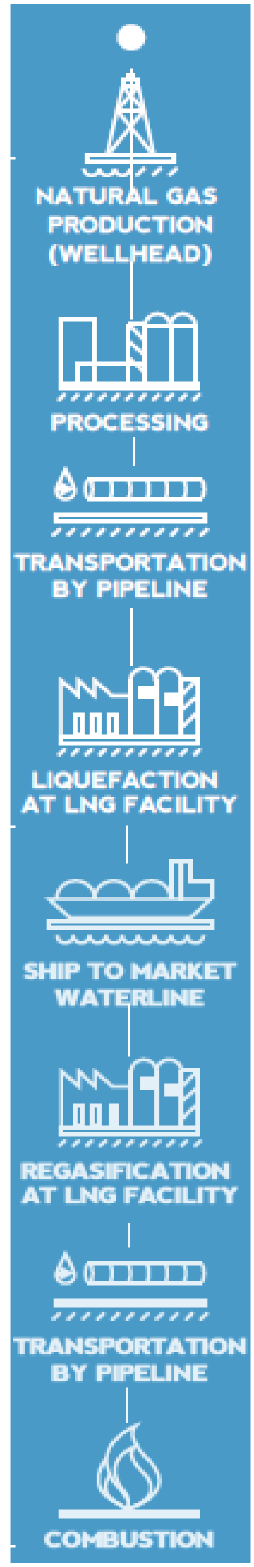
Source: LNG Growth and Opportunities in Thailand, Ptt Group

Figure 12: Global LNG Supply and Demand Forecast

PART 2:
BC's NATURAL GAS VALUE CHAIN GHG EMISSIONS

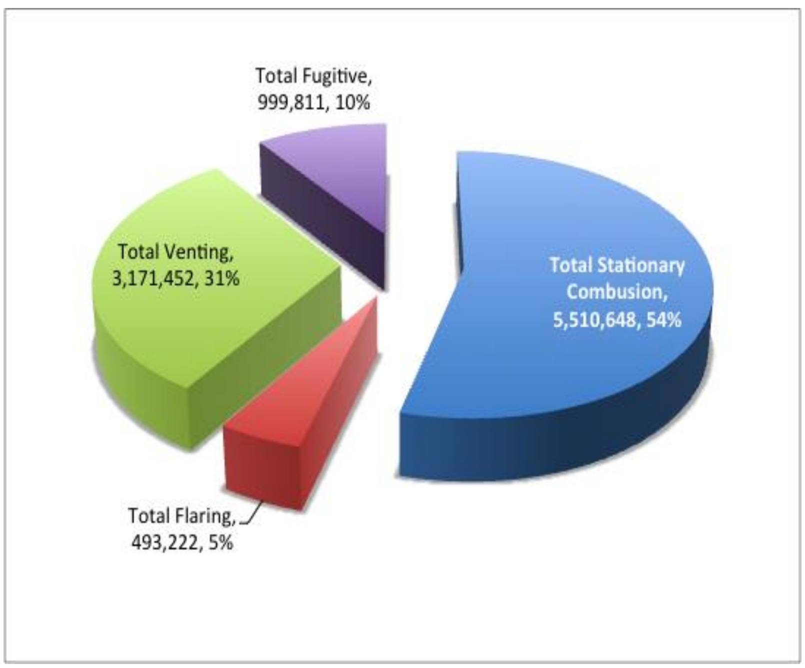
This section shows estimates for the life cycle GHG emissions for BC's natural gas overseas export value chain. As illustrated in the sidebar, this value chain includes natural gas production at the wellhead; processing (treatment and compression); distribution to LNG facilities (transportation by pipeline); liquefaction at LNG facilities; ocean transportation; regasification at LNG facility; distribution to users (transportation by pipeline); and consumption (combustion) by end users.

Side Bar Figure: BC's natural gas value chain from wellhead to consumer (combustion). Source: Clean Energy Canada



BC's GHG Emissions by Reporting Facility

British Columbia publishes a report annually on GHG emissions by reporting facility. In 2012, 46 per cent of GHG emissions released by the oil and gas sector (including pipelines and distribution channels) were from gas that was vented, flared, or from fugitive releases (see Figure 13).

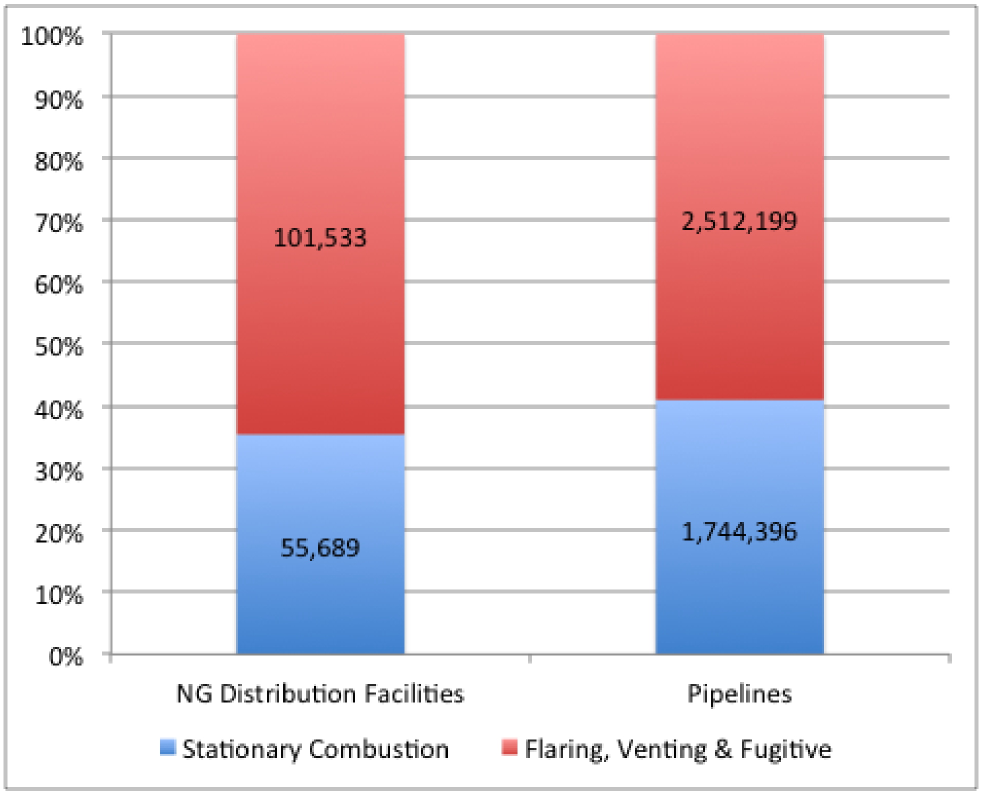


Source: BC report on GHG emissions by annual reporting facility 2012, linear facilities

Figure 13: Greenhouse gas emissions in tonnes and per cent from linear facilities in British Columbia (conventional oil and gas extraction), 2012

BC's GHG Emissions from Natural Gas Extraction & Pipeline Transport

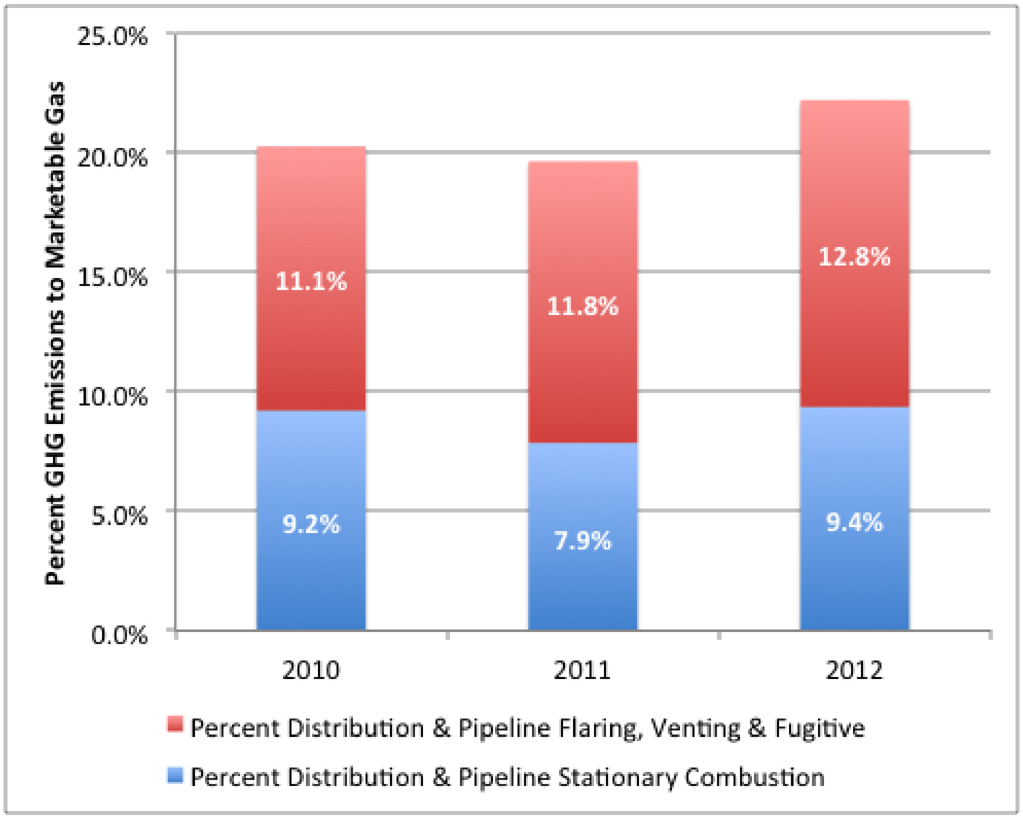
The BC report on GHG emissions by annual reporting facility also provides data on GHG emissions by both natural gas distribution and pipeline facilities. Figure 14 shows the amount of GHG emissions in tonnes of CO_2 equivalent reported by both distribution and pipeline facilities in 2012.



Source: BC report on GHG emissions by annual reporting facility 2012, linear facilities

Figure 14: GHG emissions in tonnes and percent type by natural gas distribution and pipeline facilities in British Columbia, 2012

Figure 15 shows flaring, venting, and fugitive emissions as a percentage of marketable gas for distribution and pipeline facilities from 2010 to 2012.



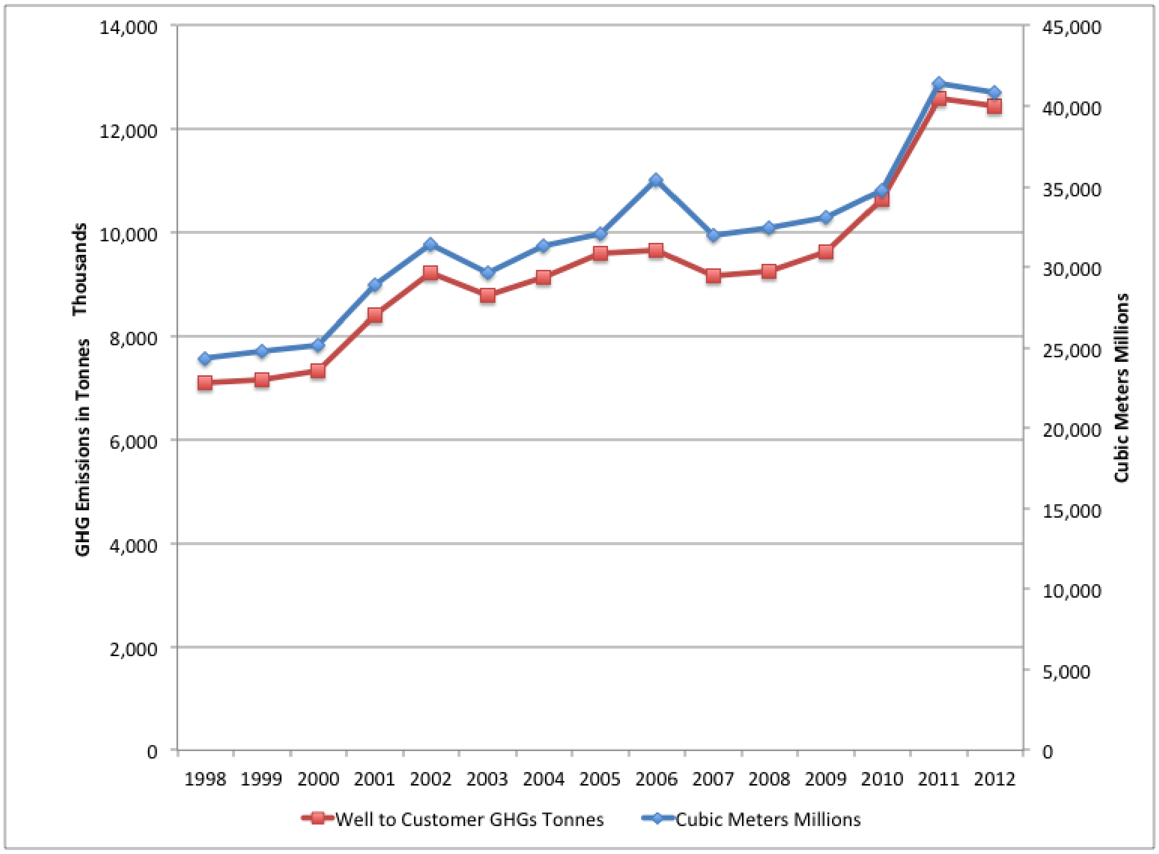
Source: BC report on GHG emissions by annual reporting facility 2012, linear facilities

Figure 15: Percentage of GHG emissions to marketable gas, distribution, and pipeline facilities in British Columbia, 2010 to 2012.

In order to reduce GHG emissions, project developers could use a combination of strategies and tools such as electrification—using electricity instead of natural gas to process natural gas and to power water pumps (rather than diesel)—and low-bleed valves and plunger lifts, which reduce leaks and venting. It is also important to limit the impact from black carbon (residual burn).

Flaring, venting, and fugitive releases of natural gas are significant for pipelines based on the BC survey. In terms of limiting pipeline losses and related GHG emissions, ensuring regular inspection and maintenance is critical. Project developers when constructing pipeline routes must also consider the one-time but material impact of removing trees that would normally act as carbon sinks.

Figure 16 shows the production of natural gas in BC and estimated GHG emissions associated with this production from 1995 to 2012. These emission estimates are derived from the algorithms published in GHGenius model for BC. As a point of reference, CO_2 equivalent emissions are also reported based on the BC large plant survey.[6] In 2012, BC produced approximately 40 billion cubic meters of natural gas. The potential for expanded production and related GHG emissions growth due to LNG projects coming online over the next decade is examined in more detail later in this section.



Source: Table 131-0001 Supply and disposition of natural gas, annual (cubic metres x 1,000,000) and CO2 equivalent emission rates from the BC GHGenius model.

Figure 16: British Columbia production of natural gas in millions of cubic meters and GHG emissions in tonnes, 1998 to 2012.

[6] British Columbia Reporting Regulation Emissions Report, 2012.

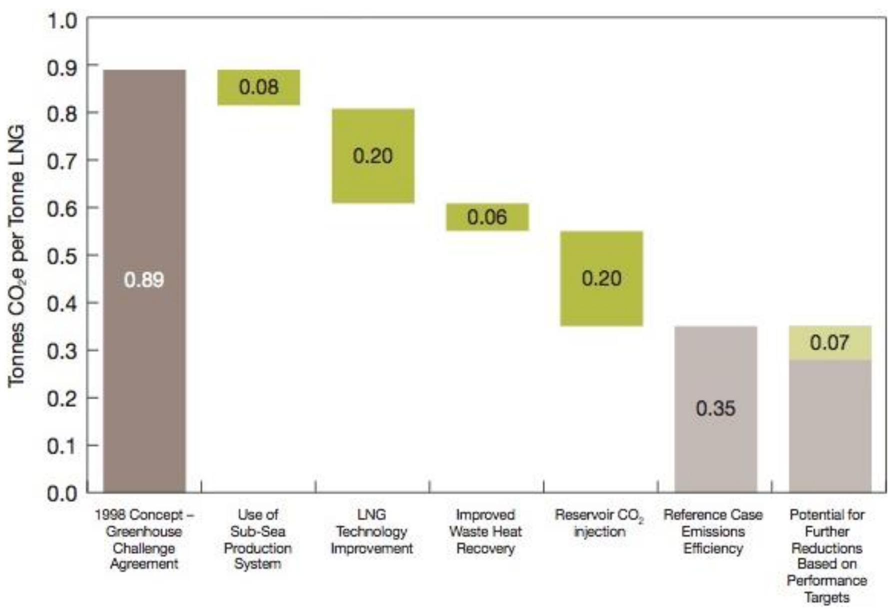
BC's GHG Emissions from LNG Plant Production

Liquefied natural gas plants are essentially industrial-sized refrigerators that run massive power-consuming condensers to cool incoming natural gas to -162 degrees Celsius. The liquefaction process also involves removal of certain components, such as dust, acid gases, helium, water, and heavy hydrocarbons, which could cause difficulty downstream.

The processing and compression of LNG involves energy and if this energy is a fossil fuel, it contributes to the life cycle GHG emissions. LNG facilities may burn natural gas to run these condensers directly. However, they can also be operated by electricity, which may use lower carbon energy sources including wind, hydro, and also natural gas burned in an efficient "combined-cycle" power plant.

While proponents have yet to develop LNG projects along the BC coastline, an opportunity exists to develop them using technology and processes that allow for best-in-class production and, in turn, lower GHG emissions. Using renewable zero emissions electricity to power these LNG plants has the potential to substantially reduce the GHG footprint of the plant. Examining the GHG emissions impact of existing LNG plants around the world can help to determine the standard that BC can aim for in order to minimize overall life cycle GHG emissions.

In Australia, the Gorgon LNG plant is a state of the art facility that has improved its GHG emissions substantially due to "changes in process technology, improved waste heat recovery on the gas turbines resulting in a significant reduction in the use of supplementary boilers and heaters, and significantly reduced GHG emissions by the injection of reservoir CO_2 into the subsurface".[7] Figure 17 illustrates how the Gorgon LNG plant achieved substantial reductions in GHG emissions from an original concept target of 0.89 tonnes of GHGs per tonne of LNG produced down to 0.35 tonnes. A further reduction of .07 tonnes of GHG emissions is currently being targeted.

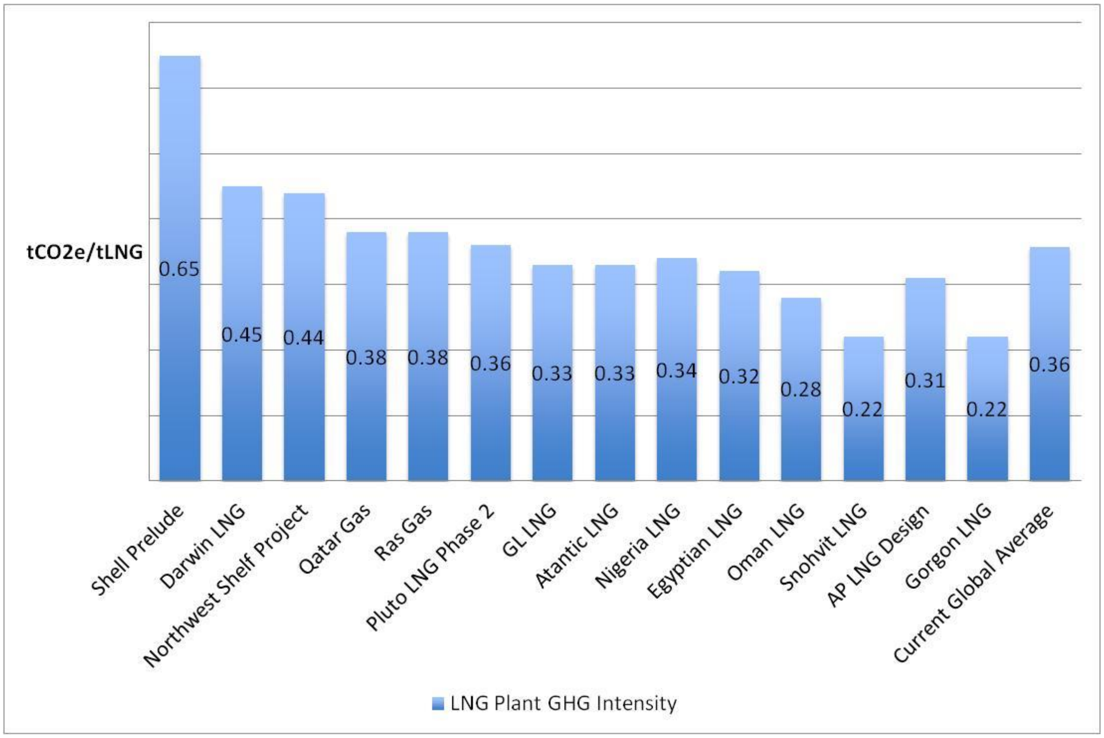


Source: Draft Environmental Impact Statement/Environmental Review and Management Programme for the Gorgon Development, Chapter 13, Greenhouse Gas Risks and Management

Figure 17: Emissions efficiency improvements, Gorgon LNG plant, Australia.

[7] Draft Environmental Impact Statement/Environmental Review and Management Programme for the Gorgon Development, Chapter 13, Greenhouse Gas Risks and Management.

GLOBE Advisors also reviewed the GHG emissions from several additional LNG production plants across the globe (as illustrated in Figure 18).



Source: Australia Pacific LNG Project Volume 5: Attachments, Attachment 31: Greenhouse Gas Assessment - LNG Facility, WorleyParsons

Figure 18: GHG emissions intensity of select international LNG plants.

The GHG emissions factors in Figure 18 represent the LNG plant compression and releases of CO_2 embedded in the natural gas. The Snohvit LNG plant, for example, has a relatively low emission factor of 0.22 tonnes per tonne of LNG produced. This plant captures and stores the CO_2 that is embedded in the natural gas.

The average GHG emission ratio for these plants is 0.36 tonnes of CO_2 equivalent per tonne of LNG produced. These LNG plants are powered from different fuels and technologies and hence, caution must be exercised in making a definitive comparison to British Columbia. In addition, some plants employing carbon capture and storage technologies have greater and easier access to rock caverns to store CO_2 than others, which makes a comparison of CO_2 equivalent intensities highly spurious amongst these international plants.

This information is useful, however, as the range of GHG emission factors illustrate the potential savings that are made possible through the use of more efficient technologies and, in some cases, carbon capture and storage. GLOBE Advisors believes that the LNG plants that will be built in BC can achieve very significant efficiencies for reduced GHG emissions due to the use of electric drive compressors that, in turn, run on a combination of new renewable power, existing British Columbia grid hydro electricity, and efficient combined-cycle natural gas generators. There is also the potential for using carbon capture and storage (CCS) technologies designed to cleanse the embedded CO_2 from the methane.

These potential CCS technologies do not necessarily involve the more traditional practice of storing CO_2 in rock caverns or depleted gas and/or oil wells. Various ways of storing carbon could include:

- **Algae / Biofuel Production**
  - Algae thrives on carbon dioxide. Algae farming with CO2 is probably the most mature technology, and the first fuel-producing plants are already going online.
- **Converting into Plastics**
  - Captured CO2 to produce polycarbonate plastics, like those used in CDs and DVDs. The idea is to take carbon dioxide emissions, and instead of sequestering them in the ground, trap them in resilient products. This approach makes sense, but because it relies largely on sequestering carbon in disposable products, like plastic forks and water bottles. So, basically, we'd be sequestering carbon every time we threw away plastic.
- **Sodium Bicarbonate (Baking Soda) Production**
  - Captures CO2 as it exits power plant smokestacks and mixes it with sodium hydroxide to form baking soda. This process, called SkyMine, also removes heavy metals and dangerous pollutants and coverts the CO2 into sodium bicarbonate. Baking soda has a variety of uses on the commercial market, and this process could help make carbon capture more economically viable. Even if the baking soda is not sold, because it is solid it is immensely easier to store it in old mines or landfills than it would be to sequester gaseous CO2 beneath the ground.
- **Calcium Carbonate / Concrete Production**
  - A new process called GreenCarbon, which, at the base of things, turns carbon dioxide into useful stuff. The GreenCarbon process mixes the CO2 with crushed calcium minerals, one of the most abundant elements in the earth's crust. The end result is calcium carbonate, an industrial chemical that's used in thousands of applications, from PVC to paper to toothpaste and, in its pure form, as wall board and chalk.
- **Other Fuel Production**
  - The carbon dioxide would be super heated to around 1,200 C and mixed with water to create various hydrocarbons of the sort is already burning in cars. The idea is to use leftover heat from nuclear or utility-scale solar thermal power generating plants. The process basically reverses combustion, and is only economically viable if the energy can come from cheap, clean sources.

A plethora of CCS technologies including those discussed above could be explored in BC.

GLOBE Advisors carefully examined GHG emission ratios developed for the GHGenius and GREET models and prepared a set of emission ratios (tonnes of GHG emissions per tonne of LNG produced) for a traditional LNG plant (based on GHGenius model results), as well as for a plant that utilizes renewable electricity and state-of-the-art practices for carbon capture and storage as part of its facility. These emission ratios are illustrated in Table 1 below.

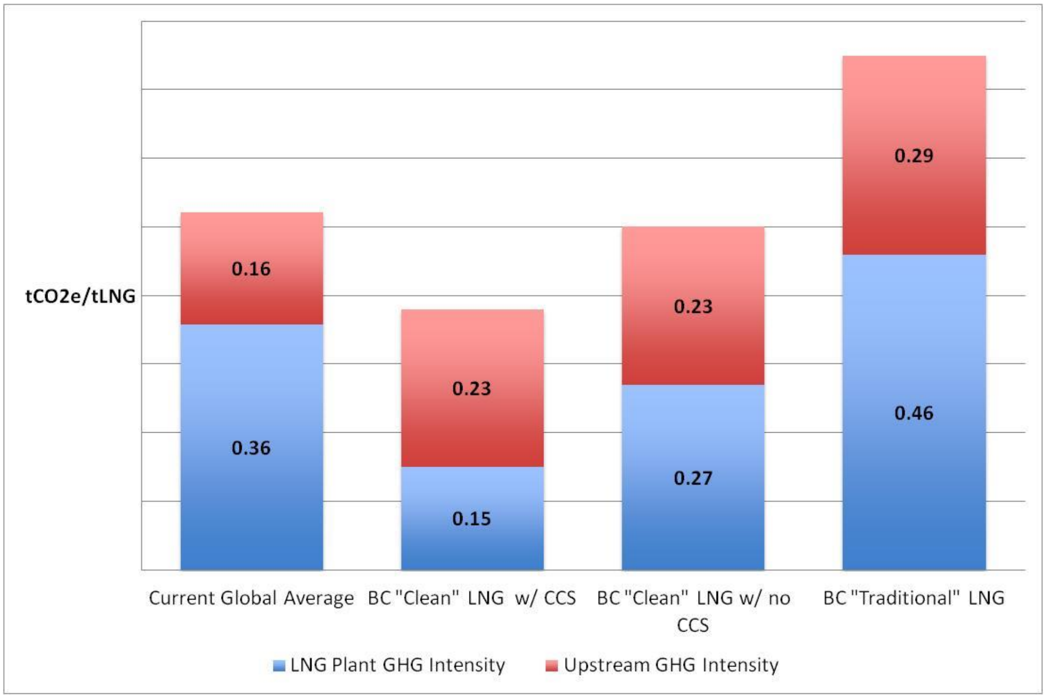
Table 1: Wellhead to waterline GHG emission factors for both "traditional" and "clean" LNG plants in BC.

	Traditional Plant GHG Emission Factor	Clean Plant GHG Emission Factor
Exploration & Wellhead		
Fuel distribution and storage	0.07	0.06
Fuel production	0.07	0.06
Feedstock recovery	0.09	0.08
Gas leaks and flares	0.07	0.04
Subtotal	**0.29**	**0.23**
LNG Plant		
CO_2, H_2S removed from NG	0.12	0.01
Liquefaction at LNG Plants	0.33	0.14
Subtotal	**0.46**	**0.15**
Well-to-Water Upstream with CCS	**0.75**	**0.38**
Well-to-Water with no CCS	**0.75**	**0.50**

Based on the GHGenius model, a traditional LNG plant in BC that does not utilize "clean" practices (including renewable power supplemented by CCS) will produce well-to-water GHG emissions of approximately 0.75 tCO2e / tLNG. However, if LNG plants in BC utilize renewable power for compressing the natural gas and, conceivably, employ CCS technologies to capture the embedded CO_2, a well-to-water emissions factor of 0.38 tonnes per tonne of LNG product is achievable.[8] Using some combination of renewable energy technology and/or CCS can achieve well-to-water emissions somewhere in between 0.75 and 0.38 tCO2e / tLNG produced.

[8] GLOBE includes the exploration, production, distribution, and LNG facilities in its upstream emissions.

As illustrated in Figure 19, the global average for upstream GHG emissions combined with LNG plant emissions (well-to-water ratio) for various LNG projects around the world is 0.52 tCO2e / tLNG produced. Included in this graph are three GHG emission factors that represent hypothetical LNG plants in British Columbia under three scenarios. These scenarios include the "traditional" plant emissions factor of 0.75 tCO2e / tLNG based on the GHGenius model, the "clean" plant emissions factor of 0.38 tCO2e / tLNG that includes application of CCS technologies, and a hybrid scenario that does not include CCS and results in plant emissions of 0.50 tCO2e / tLNG.



Source: GLOBE Advisors and Australia Pacific LNG Project Volume 5: Attachments, Attachment 31: Greenhouse Gas Assessment - LNG Facility, WorleyParsons

Figure 19: Global average well-to-waterline GHG emissions intensity compared to three BC LNG plant well-to-waterline GHG emissions scenarios.

GLOBE Advisors believes that a target of 0.15 tonnes of GHG emissions per tonne of LNG produced (or a 58 per cent reduction from a "traditional" LNG plant powered by fossil fuels) is both possible and plausible, as the LNG plants in BC can employ near-zero emission clean electricity to power the compressors. This improvement in emission efficiency is in-line with the Gorgon targets that were achieved in Australia.[9]

Liquefied natural gas plants in BC have the potential to produce some of the lowest well-to-waterline value chain GHG emissions if both renewable electricity and CCS technologies are applied. However, without the application of CCS, BC plants would be marginally less GHG emissions intensive than the global average. If LNG plants in BC do not employ renewable energy and new technologies in order to reduce emissions, then the traditional emission rate of 0.75 tCO2e / tLNG would be considerably higher than the global average of 0.52 tCO2e / tLNG produced.

[9] The CO_2 venting and possible capture and sequestration is assumed to occur at the LNG plant phase similar to what has been reported for the international examples including the Gorgon Plant. An argument can be made that CO_2 venting occurs at the upstream phase; however, this does not change the overall life cycle CO_2 intensity.

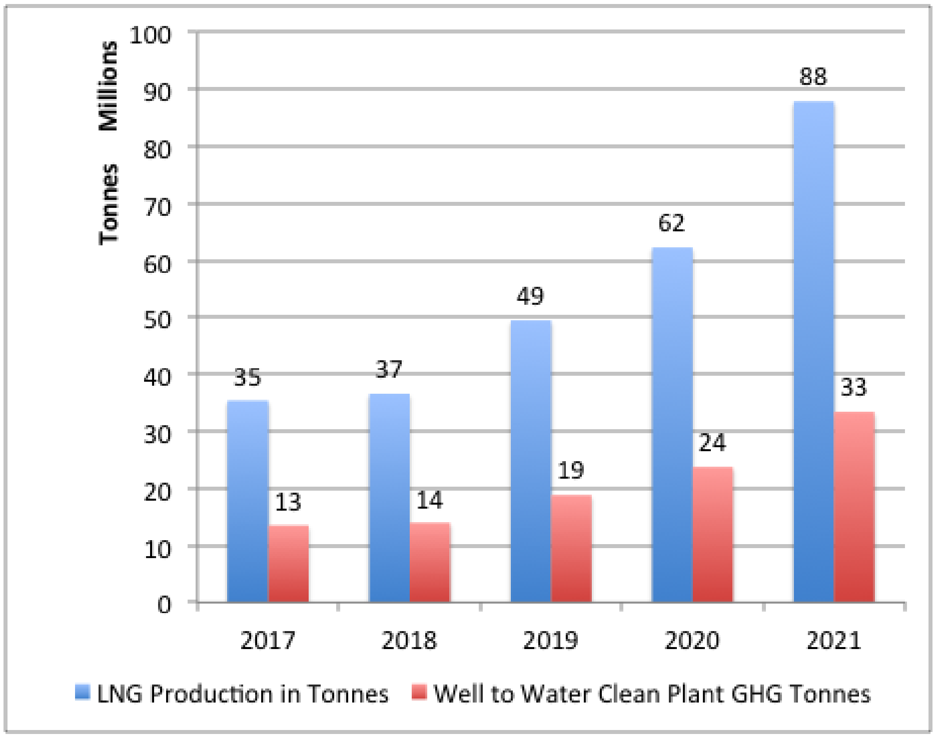
At present, there are a total of ten LNG projects proposed for development in British Columbia. Table 2 provides an overview of each project's proposed capacity and its current status. If all of these projects were to proceed to full potential capacity, approximately 131 million metric tonnes per annum (mmtpa) of LNG would be produced and available for export to overseas markets.

Table 2: Overview of forecast LNG infrastructure projects in BC, 2017 to 2021.

Project Name (Location)	**Project Lead & Partners**	**Potential Capacity (mmtpa)**	**Current Status**
Douglas Channel Energy Project (Kitimat)	**BC LNG Export Co-Operative** Haisla Nation Golar LNG	0.9	Export license approved
LNG Canada (Kitimat)	**Shell Canada Ltd.** Korea Gas Corp. (KOGAS), Mitsubishi Corp., PetroChina Company Ltd.	24	Export license approved
Kitimat LNG (Kitimat)	**Apache Canada Ltd.** Chevron Canada Ltd.	15	Export license approved
Prince Rupert LNG (Prince Rupert)	**BG Group** Spectra Energy Natural Gas Transportation System	14	NEB currently reviewing
Pacific Northwest LNG (Prince Rupert)	**Progress Energy Canada Ltd.** Petroliam Nasional Berhad (Petronas) JAPEX	18	NEB currently reviewing
Imperial Oil / Exxon Mobil (Prince Rupert or Kitimat)	**Imperial Oil** Exxon	30	NEB currently reviewing
AltaGas Idemitsu Joint Venture (Prince Rupert or Kitimat)	**AltaGas** Idemitsu Kosan Co. Ltd.	2.3	NEB currently reviewing
Woodfibre LNG (Squamish)	Woodfibre Natural Gas Ltd.	3	NEB currently reviewing
Aurora LNG (Prince Rupert)	**CNOOC** Inpex JGC Corp.	12	NEB currently reviewing
Kitsault Energy LNG (Kitsault)	Kitsault Energy	15	Feasibility phase
Total Proposed LNG Production in BC (MMTPA)		**131.2**	
Estimated LNG Production in BC by 2021 (131.2 MMTPA X 67%)		**87.9**	

Realistically, not all ten of the proposed LNG projects listed in the table above will proceed to full capacity. In this report, GLOBE Advisors worked with an assumption that two-thirds (67 per cent) of the total capacity proposed for construction will come on stream by 2021. In this regard, once constructed and operational, these LNG projects will produce 87.9 million metric tonnes of LNG per annum (mmtpa).

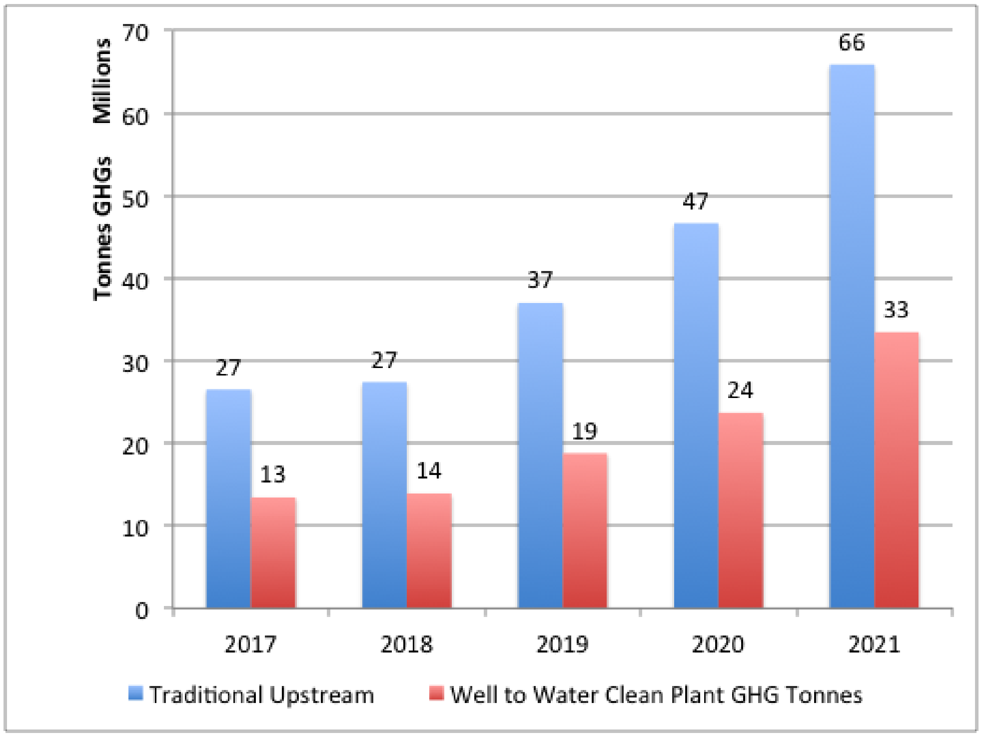
Figure 20 shows the expected production of natural gas and associated GHG emissions from 2017 to 2021, as the estimated LNG plant production in BC begins to come on stream. Under this scenario, approximately 33 million tonnes of GHG emissions (CO_2 equivalent) would be produced in 2021 as the life cycle GHG emissions from wellhead to waterline, assuming that LNG plants in BC utilize "cleanest" practices for plant operations and upstream management of GHG emissions. LNG production units are in millions of metric tonnes and GHG emissions are in tonnes of CO_2e.



Source: GLOBE Advisors

Figure 20: British Columbia projected production of LNG and related GHG emissions in Tonnes, 2017 to 2021 (based on estimated 67% of proposed LNG infrastructure construction proceeds to full operation).

Figure 21 shows the relevant tonnes of GHG emissions (CO_2 equivalent) for a LNG plant in BC using the "cleanest" production processes relative to GHG emissions of LNG produced in BC from a "traditional" plant, based on 88 mmtpa of LNG produced.

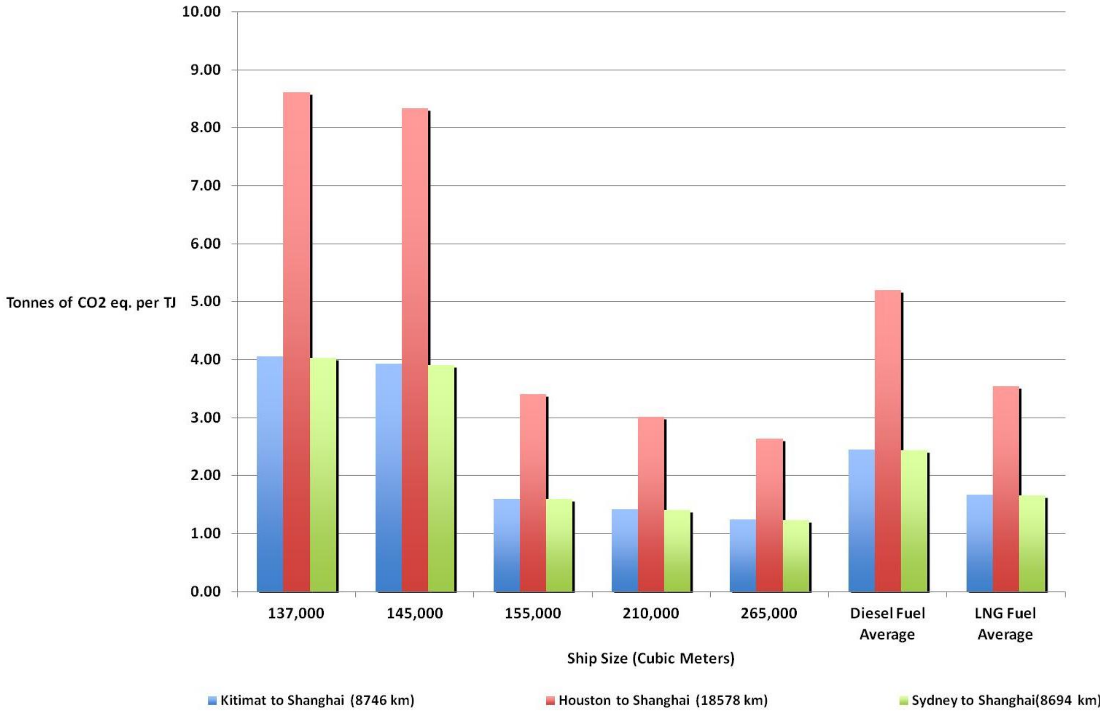


Source: GHGenius and GLOBE Advisors

Figure 21: Well to waterline GHG emissions for a "traditional" LNG plant in BC (modeled with GHGenius) compared with a "clean" LNG plant.

GHG Emissions from LNG Tanker Transportation

Tanker shipping accounts for a certain level of GHG emissions and these emissions should be included in the full life cycle analysis. Shipping emissions occur during the consumption of fuel used to power the propulsion engine. The amount of GHG emissions from LNG tankers depends on the distance shipped, the type of fuel consumed (diesel or natural gas), and the size of the tanker. Figure 22 shows various LNG tanker emission factors based on these three variables.

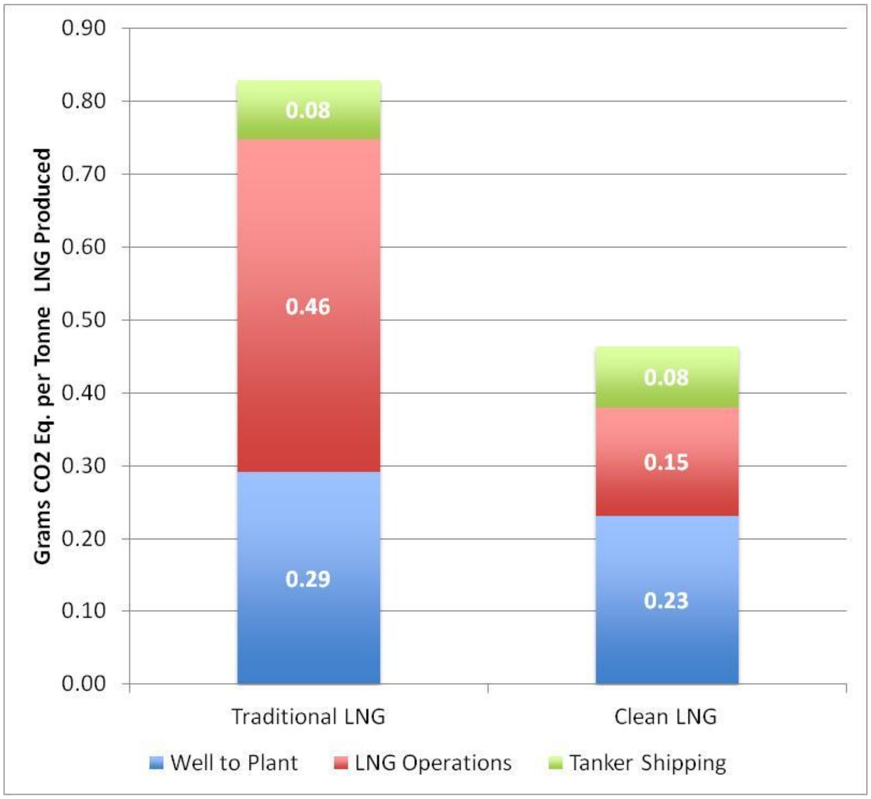


Source: University of Queensland, Life Cycle Assessment (LCA) of Liquefied Natural Gas (LNG) and its environmental impact as a low carbon energy source.

Figure 22: GHG emission factors by distance shipped, tanker size, and fuel type.

The route from Kitimat, BC, to Shanghai, China, for example, is considerably lower than from Houston, Texas. As a consequence, so are the related GHG emissions. The distance from Kitimat, BC, and Sydney, Australia, are nearly identical and as such, so are the GHG emissions from marine transportation given similar vessels are used. It should be noted that GHG emissions are further reduced when bunker or diesel fuel is switched for cleaner LNG fuel used to power ship transportation.

Figure 23 shows these GHG emission factors for both a "traditional" LNG plant (based on the GHGenius model) and for the potential "clean" plant (based on GLOBE's target for best-in-class operations).

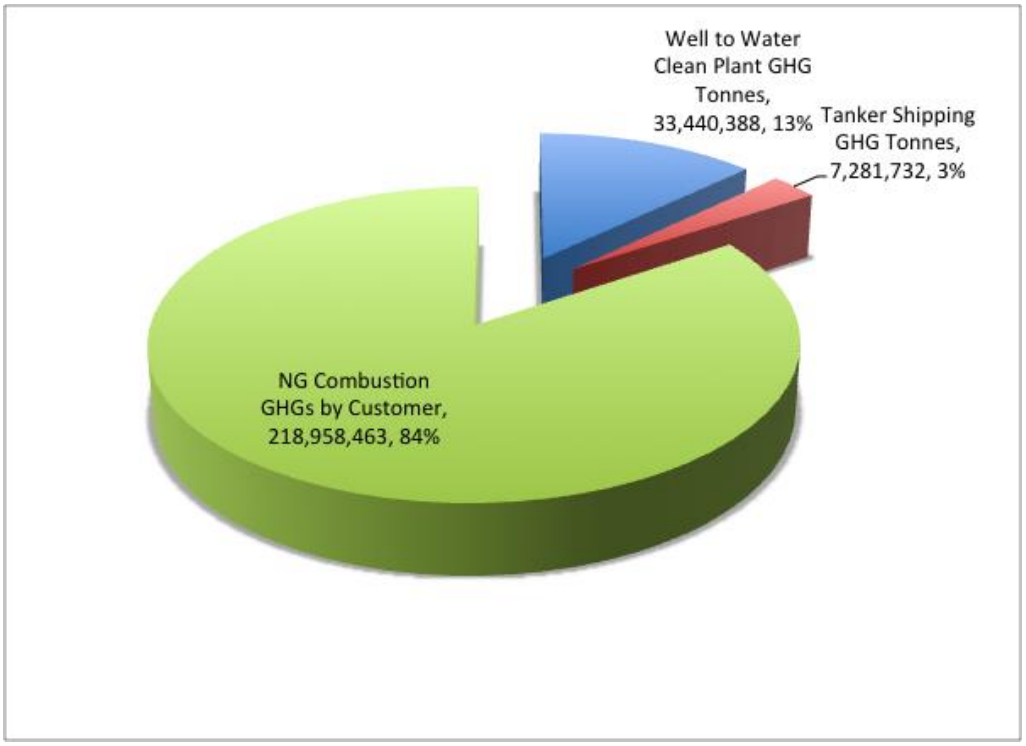


Source: GHGenius and GLOBE Advisors

Figure 23: GHG emission factors for "traditional" and "clean" LNG plants in BC.

BC's GHG Life Cycle Emissions from Wellhead to the Customer

Figure 24 shows the potential GHG emissions (CO_2 equivalent) in tonnes and percentages for the full natural gas and LNG life cycle based on export of 88 mmtpa of LNG from BC to Asian markets.



Source: GLOBE Advisors and GHGenius

Figure 24: GHG emissions impact for the full life cycle of BC natural gas and LNG from the wellhead to the customer, tonnes of CO_2 (based on 88 MMTPA production)

GLOBE Advisors has assumed that the proposed LNG plants in BC will have been developed in-line with current best-in-class “clean” LNG projects and as such, will produce approximately 0.38 tonnes CO2e per tonne of LNG. The tanker transportation emissions amount to a further 0.08 tonnes CO2e per tonne of LNG production. Thus, delivering the product to the customer results in 0.46 tonnes of GHG emissions for every tonne of LNG produced.

However, the wellhead to market GHG emission factors pale in comparison with the full life cycle of BC's natural gas when combustion factors are included, based on the customer burning BC's natural gas product for electrical power (as illustrated in Figure 26 above). As illustrated, BC's upstream GHG emissions from wellhead to waterline are equal to 16 per cent of total life cycle GHG emissions.

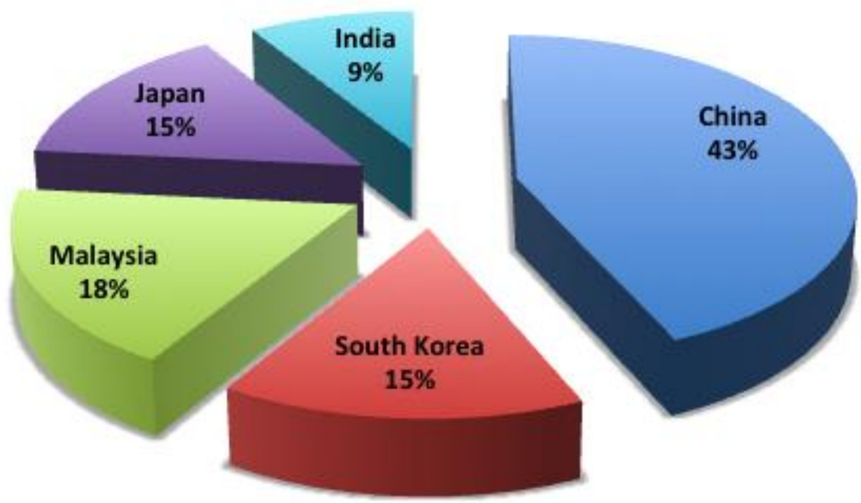
PART 3:
IMPACT OF BC's LNG EXPORTS ON GLOBAL GHG EMISSIONS

This section addresses the issue of whether or not natural gas being exported from BC will be consumed as an alternative to fuel from other sources, and in particular, as a replacement to coal.

The question being addressed is to what extent will BC's LNG be replacing higher GHG intensive fuels. Replacing coal with natural gas has the potential to reduce GHG emissions substantially. This analysis requires a more detailed examination of the end user of BC's LNG exports.

Estimated LNG Exports by Country

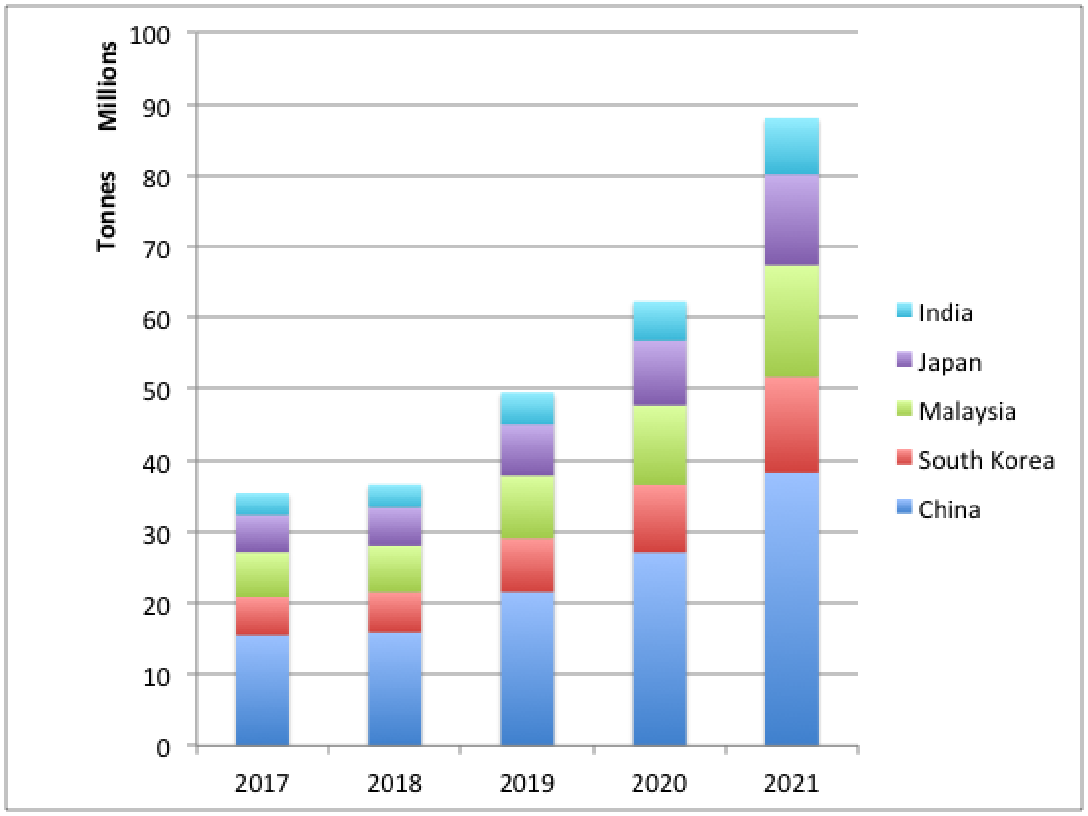
GLOBE Advisors estimated the distribution of British Columbia's LNG exports to Asian economies based on examining proposed LNG plant investment shares by various Asian partners, as well as on projected demand recently published in the International Energy Agency's World Outlook for 2013. These estimated shares are illustrated in Figure 25 below.



Source: International Energy Agency and various BC LNG infrastructure websites on investor partners

Figure 1725: Distribution of BC's LNG exports to Asian countries.

British Columbia's potential LNG export capacity by country is shown in Figure 26. As illustrated, China is the dominant economy for receiving LNG exports from British Columbia based on the current proposed projects.



Source: International Energy Agency and BC LNG infrastructure projects based on investor partners.

Figure 26: Potential LNG exports to Asian countries, 2017 to 2021 (in mmtpa).

Table 3 shows the ten proposed LNG projects and their major partners, mostly from Asia. Based on these partners, GLOBE has provided an anecdotal discussion of possible GHG impacts within the various customer markets in the following section.

Table 3: Target Country Markets of Forecast LNG Projects in BC, 2017 to 2021

Project Name (Location)	**Project Lead & Partners**	**Target Country / Region**	**Impact on Energy Consumption**
Douglas Channel Energy Project (Kitimat)	**BC LNG Export Co-Operative** Haisla Nation Golar LNG	Asia	Mixture of replacing coal and natural gas from other sources
LNG Canada (Kitimat)	**Shell Canada Ltd.**	Asia	Mixture of replacing coal and natural gas from other sources
	Korea Gas Corp. (KOGAS)	South Korea	Mixture of replacing coal and LNG from other sources
	Mitsubishi Corp.	Japan	Mixture of replacing coal and LNG from other sources
	PetroChina Company Ltd.	China	Mixture of replacing coal and natural gas from other sources
Kitimat LNG (Kitimat)	**Apache Canada Ltd.** Chevron Canada Ltd.	Asian utility companies	Mixture of replacing coal and natural gas from other sources
Prince Rupert LNG (Prince Rupert)	**BG Group** Spectra Energy Natural Gas Transportation System	China	Mixture of replacing coal and natural gas from other sources
		Japan	Mixture of replacing coal and LNG from other sources
		South Korea	Mixture of replacing coal and LNG from other sources
		India	Mixture of replacing coal and natural gas from other sources
Pacific Northwest LNG (Prince Rupert)	**Progress Energy Canada Ltd.** Petroliam Nasional Berhad (Petronas)	Malaysia	Replace diesel power
	JAPEX	Japan	Mixture of replacing coal and LNG from other sources
Imperial Oil / Exxon Mobil (Prince Rupert or Kitimat)	**Imperial Oil** Exxon	Asia and other markets	Mixture of replacing coal and natural gas from other sources
Woodfibre LNG (Squamish)	n/a	Asia and other markets	Mixture of replacing coal and natural gas from other sources
AltaGas Idemitsu Joint Venture (Prince Rupert or Kitimat)	**AltaGas** Idemitsu Kosan Co. Ltd.	Japan	Mixture of replacing coal and LNG from other sources
Aurora LNG (Prince Rupert)	**CNOOC**	China	Mixture of replacing coal and natural gas from other sources
	Inpex	Indonesia	Replace diesel power
	JGC Corp.	Japan	Mixture of replacing coal and LNG from other sources
Kitsault Energy LNG (Kitsault)	Kitsault Energy	Asia and other markets	Mixture of replacing coal and natural gas from other sources

BC's Natural Gas Life Cycle Impact on Global GHG Emissions

As a fossil fuel, GHG emissions are emitted when natural gas is burned. However, the GHG emissions associated with burning natural gas are lower than for most other fossil fuels.

When natural gas is used to replace coal and/or natural gas being sourced from other locations with higher life cycle GHG emissions, it will have an overall positive impact on reducing global GHG emissions and local air pollutants.

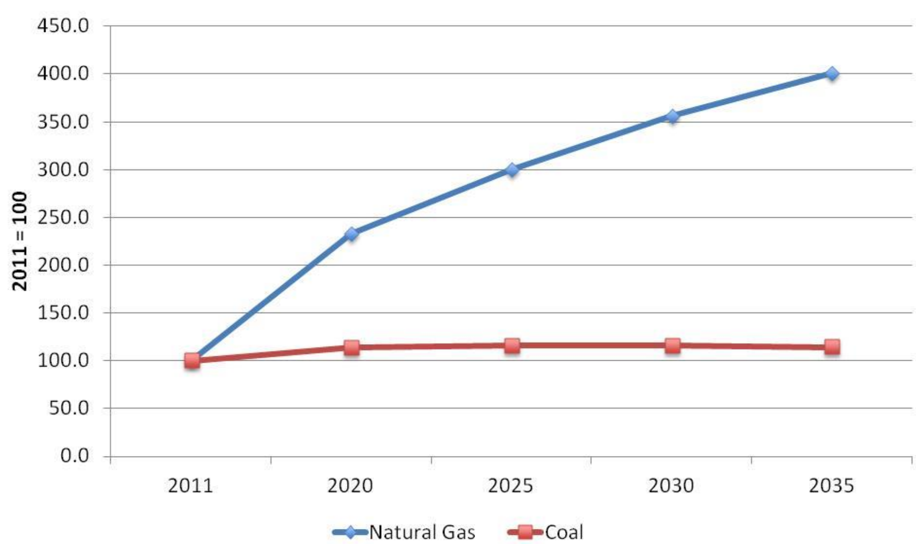
Natural gas is a particularly attractive fuel for countries and regions that are urbanizing and seeking to satisfy rapid growth in energy demand, such as China and India. These countries will largely determine the extent to which natural gas use expands over the next 25 years.[10]

As described earlier in this report in the section on the projected global demand for natural gas, the natural gas imported by Asian economies is expected to largely replace existing or planned coal thermal power and, hence, will provide an overall reduction in CO_2e emissions due to lower combustion emissions of natural gas over coal.

A more detailed examination of BC's primary markets for the export of LNG and the related impacts on local GHG emissions within each market follows below.

China

Based on the IEA's *New Policies Scenario*, the demand for natural gas in China is expected to quadruple by 2035, while the demand for coal is expected to remain relatively constant (see Figure 27).



Source: IEA 2013 World Energy Outlook, *New Policies Scenario*

Figure 27: Demand for natural gas and coal in China, 2011 to 2035.

[10] See: http://www.iea.org/newsroomandevents/pressreleases/2011/june/name,20306,en.html

At the same time, China is experiencing a serious shortage in natural gas. The problem is particularly acute in northern China, where its air is polluted and where officials are trying to end large-scale use of coal for heating and power generation. The country's domestic supply of natural gas cannot meet demand. “China's demand was 143.8 billion cubic meters, of which 40 billion had to be imported. It is estimated that China's dependence on imported natural gas will exceed 35 per cent by 2015.”[11]

The efforts to reduce coal usage in the Beijing-Tianjin-Hebei region are unprecedented. “On August 25, the Beijing Environmental Protection Bureau issued guidelines demanding that 137 boilers of about 4,900 tons of steam capacity in six urban districts switch from coal to gas from this year to 2015, thus reducing coal consumption by 1.2 million tons. Nearly all industrial and corporate boilers in the entire city were told to switch from coal to gas by 2016.”[12]

According to the United States Energy Information Administration, “natural gas usage in China has also increased rapidly in recent years, and China has looked to raise natural gas imports via pipeline and liquefied natural gas (LNG). China is also the world's largest top coal producer and consumer and accounted for about half of the global coal consumption, an important factor in world energy-related CO2 emissions.”[13]

Natural gas exports to China and the rest of Asia will be substantial. This power will, however, be produced with fewer GHG emissions than through the use of other fossil fuels (coal, diesel, etc.). Note that the IEA in an interview with the Press regarding the 2013 World Outlook Report rejected calls for British Columbia to forgo the production and export to Asia of LNG due to concerns that the province would not meet its own GHG reduction targets. Growing LNG imports in China and elsewhere should reduce the need for coal-fired electricity, leading to a global reduction in GHG emissions.

GLOBE Advisors believes that the strong Chinese demand for natural gas will coincide with a lower emphasis on coal thermal power due to the strong pressure to reduce pollution and CO_2 equivalent emissions as part of its 12th Five-Year Plan and future Five-Year Plans.

Japan

Japan is currently the world's largest importer of LNG. In light of the country’s lack of sufficient domestic hydrocarbon resources, Japanese energy companies are actively pursuing participation in upstream oil and natural gas projects overseas and provide engineering, construction, financial, and project management services for energy projects around the world. Coal continues to account for a significant share of total energy consumption, although natural gas is increasingly important as a fuel source.

“Because of its limited natural gas resources, Japan must rely on imports to meet its natural gas needs. Japan began importing LNG from Alaska in 1969, making it a pioneer in the global LNG trade. Due to environmental concerns, the Japanese government has encouraged natural gas consumption in the country. Japan is the world’s largest LNG importer, holding about 33 per cent of the global market in 2011.”[14]

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[11] See: http://english.caixin.com/2013-11-29/100611459.html
[12] Ibid
[13] See: http://www.eia.gov/countries/cab.cfm?fips=CH
[14] Ibid

With respect to nuclear power, since the Fukushima disaster, nuclear power production may decrease in Japan. Japan shut down all 50 commercial reactors in the wake of the 2011 earthquake and tsunami that triggered a nuclear crisis at the Fukushima plant. Two reactors were restarted in July of 2012, but were taken offline again in September 2013 for inspections, leaving the country without any nuclear power.

Coal has been the dominant replacement of power in Japan since the shutdown of nuclear power facilities in that country. As such, GLOBE Advisors has assumed that increased natural gas usage will be used to replace coal power that is currently being consumed, or natural gas sourced from other less “clean” sources.[15] As such, fuel switching from coal or “dirtier” natural gas to “cleaner” natural gas imported from BC when the LNG plants become operational (starting in 2017) will have positive impacts on reducing GHG emissions in Japan.

However, according to senior Japanese energy officials, nuclear power is expected to remain a key part of Japan’s energy profile, despite the safety concerns raised by the Fukushima disaster.[16] Prime Minister Shinzo Abe has openly backed a return to the widespread use of atomic energy, but the Japanese public remains divided, with opponents citing continued safety fears. The amount to which Japan returns to sourcing its power from nuclear plants may have an affect on the overall GHG benefits from natural gas imported from BC if it is used to replace nuclear.

Malaysia

According to the IEA, 37 per cent of the country’s energy consumption is met by natural gas and 18 per cent by coal. Thirty-nine per cent is being met by oil; 4 per cent by biomass and waste; and 2 per cent by hydroelectric power.

Malaysia was the world's second largest exporter of LNG after Qatar in 2012. Malaysia's state-owned Petronas dominates the natural gas sector. The company has a monopoly on all upstream natural gas developments, and it also plays a leading role in downstream activities and the LNG trade. The power sector consumes about 74 per cent of the Malaysia's natural gas market sales, and demand for power is expected to increase. Rising domestic demand and LNG export contracts place pressure on the gas supply. Malaysia is actively investing in reservoir development to meet these needs.

To a large extent, growing LNG imports will be effectively replacing coal and/or oil power, although some natural gas imports will represent incremental power. For these opportunities, BC natural gas can have a positive impact on reducing global GHG emissions, particularly if its natural gas is “cleaner” than the global average.

[15] See: http://www.eia.gov/countries/analysisbriefs/cabs/Japan/pdf.pdf
[16] See: http://www.japantoday.com/category/national/view/nuclear-power-still-key-to-japan-energy-mix-officials

South Korea

South Korea is one of the top energy importers in the world. In 2011, the country was the second largest importer of LNG, the third largest importer of coal, and the fifth largest importer of crude oil. South Korea has no international oil or natural gas pipelines, and relies exclusively on tanker shipments of LNG and crude oil. According to the IEA, natural gas accounts for 17 per cent of total energy consumption; petroleum 42 per cent; coal 29 per cent; and nuclear 13 per cent.

South Korea is the second largest importer of LNG in the world after Japan. "South Korea consumed 1.6 trillion cubic feet (Tcf) of natural gas in 2011, which was an increase of more than 125 per cent from 2001. The city gas network – serving residential, commercial, and industrial consumers – accounted for the majority (54 per cent in 2011) of natural gas sales, while power generation companies made up nearly all of the remaining shares."[17]

South Korea has four LNG regasification facilities, with a total capacity of 4.5 Tcf per year. Nearly an additional 1 Tcf of regasification capacity had been added since 2010.

With respect to electricity generation, 69 per cent comes from conventional thermal sources, 30 per cent came from nuclear power, and 1 per cent from renewable sources. It uses coal for a significant amount of its electricity generation (approximately 50%) and coal consumption has grown in the last few years. South Korea also has 14 new nuclear facilities planned for 2025, six of which are currently under construction.

These figures provide strong opportunities for natural gas power to replace thermal coal power to some extent. It is assumed that exports of natural gas from BC to South Korea will likely replace coal and, as such, will have an overall net benefit to reducing global GHG emissions.

India

In 2011, India was the fourth largest energy consumer in the world after the United States, China, and Russia. India's largest energy source is coal, followed by petroleum and traditional biomass (e.g., burning firewood and waste).

The power sector is the fastest growing area of energy demand, increasing from 23 per cent to 38 per cent of total energy consumption between 1990 and 2009. An estimated 25 per cent of the population lacks basic access to electricity.

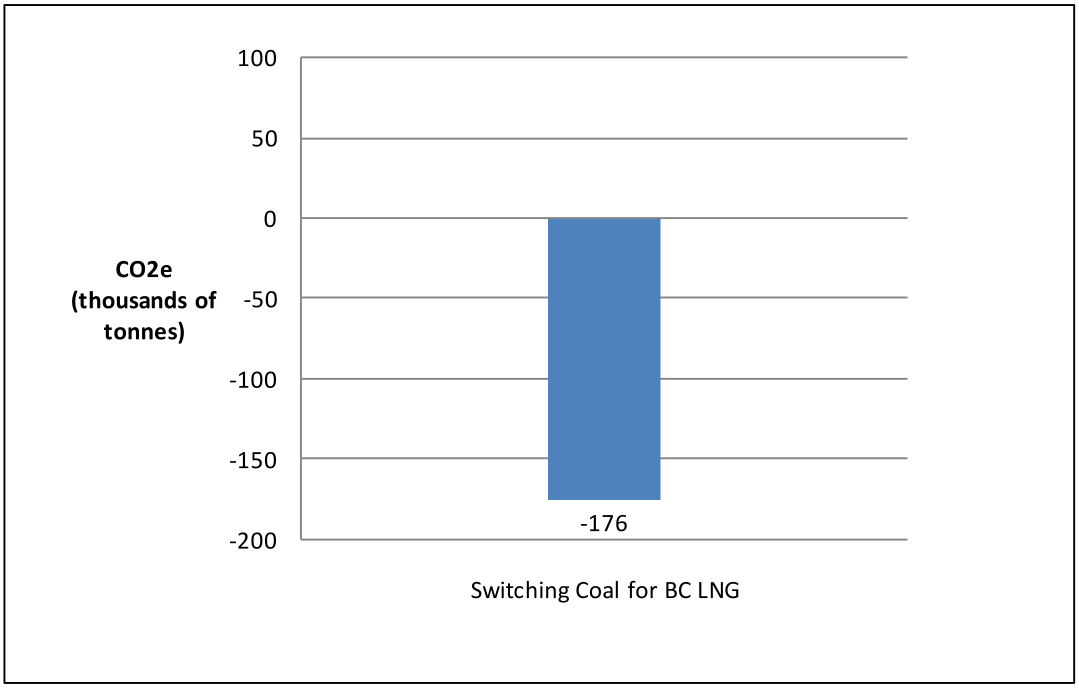
There is a strong need to balance the demand for electricity with environmental concerns and shift away from thermal power, which should bode well for future LNG exports from BC to India and have an overall net benefit to reducing global GHG emissions.[18] GLOBE Advisors believes that switching from coal to natural gas will become a reality as a result of this strong need for cleaner energy in India.

[17] See: http://www.eia.gov/countries/cab.cfm?fips=KS
[18] See: http://www.eia.gov/countries/cab.cfm?fips=IN

Natural Gas Switching Scenarios

GLOBE Advisors examined the impact on global GHG emissions of two scenarios where natural gas from BC is exported as LNG to Asian markets.

The first scenario looks at the GHG emissions impact of having natural gas from BC completely replace coal-powered electricity production and/or serve as an alternative to the construction of new coal-fired power facilities. In this "*Full Coal Switching*" scenario, the GHG emissions avoided from combustion of natural gas over coal alone amounts to an annual savings of 176 million tonnes of CO_2e in 2021, a fairly significant savings in overall global GHG emissions as illustrated in Figure 28 below.



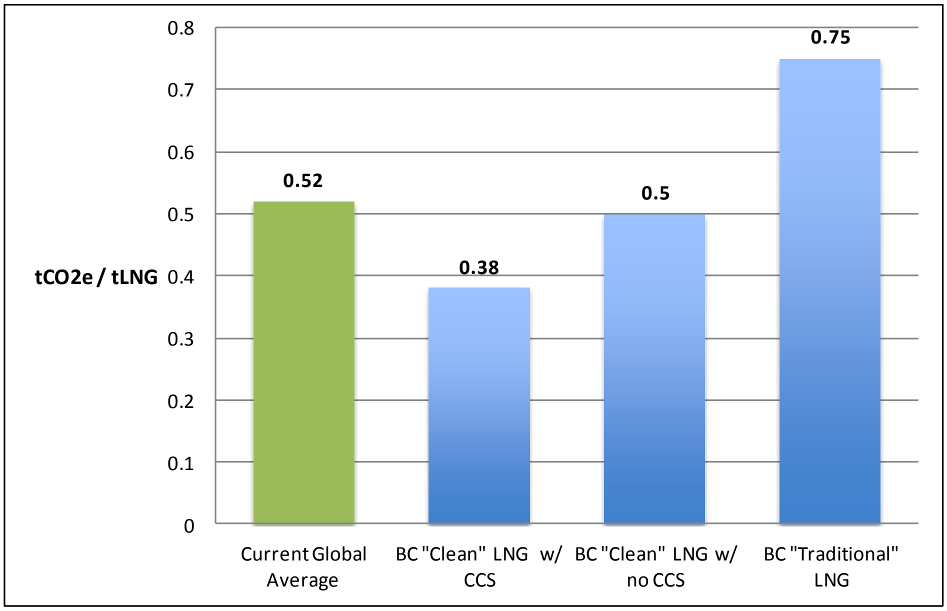
Source: GLOBE Advisors

Figure 28: Annual GHG emissions impact of having BC natural gas completely replace coal-powered electricity production under the *Full Coal Switching* scenario (assuming LNG production of 88 mmtpa).

These GHG emissions savings were calculated by subtracting the total GHG emissions that are produced from the combustion of the LNG produced in BC from the GHG emissions that would have otherwise been produced from burning the equal amount of coal used to generate the same amount of power (in terajoules).

The second scenario looked at the impact from having natural gas exported from BC to Asian markets replace natural gas coming from other global suppliers. Under this "*Full Natural Gas Switching*" scenario, the global average for LNG value chain GHG emissions was compared to BC's hypothetical LNG production scenarios.

The well-to-waterline GHG emission factors for the "clean" LNG plant and the "traditional" LNG plant scenarios against the global GHG emissions average are illustrated in Figure 29.



Source: GLOBE Advisors

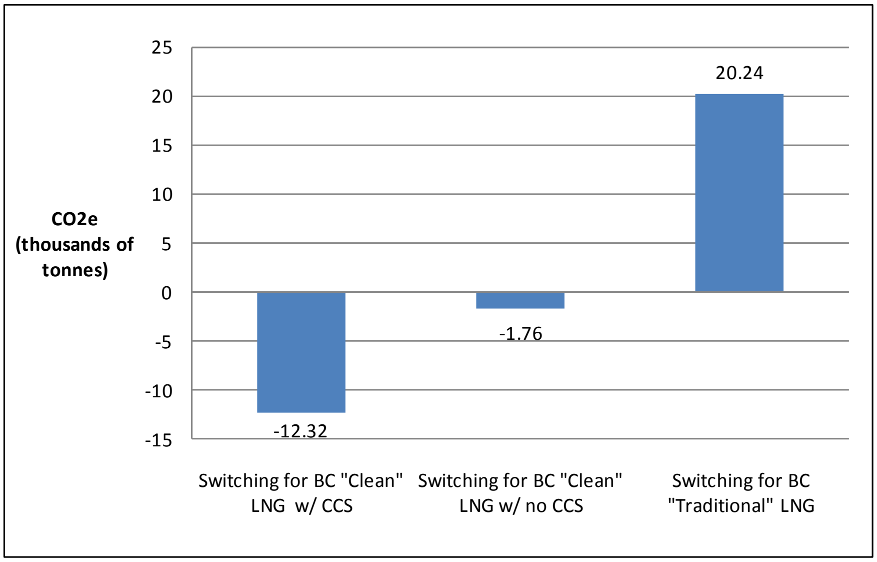
Figure 29: CO2e emission factors for various well-to-waterline LNG plant scenarios in BC against the international average (tCO_2e / tLNG).

Achieving the "clean" LNG plant well-to-waterline factor of 0.38 tCO_2e / tLNG produced, there would be a reduction of global GHG emissions in the range of 12.4 million tonnes of CO_2e per year (based on BC's estimated annual production level of 88 mmtpa by 2021), which is the difference between the "clean" LNG plant well-to-waterline emissions of 33.4 million tonnes of CO_2e and the 45.8 million tonnes of CO_2e that would be produced for an equal amount of LNG using the global average life cycle emissions value of 0.52 tCO_2e / tLNG.

If BC's LNG plants apply renewable energy and upstream best practices without CCS technology, the reduction in global GHG emissions is lower at 1.8 million tonnes of CO_2e per year for the production of 88 mmtpa of LNG in BC. Nonetheless, even in the absence of CCS, lower GHG emissions occur when BC natural gas replaces the same product produced elsewhere.

On the other hand, if the LNG plants in BC adopt the "traditional" LNG plant average of 0.75 tCO_2e / tLNG produced (in line with the GHG emissions factor published by the GHGenius model), then BC natural gas that replaces gas from other global suppliers would actually add to overall global CO_2e emissions by a factor of 20.2 million tonnes per annum (based on applying the global average life cycle GHG emissions factor of 0.52 tCO_2e / tLNG).

The net CO_2e savings based on BC natural gas replacing natural gas sourced from global suppliers (applying the global average) is shown in Figure 30.[19] Note that the "traditional" LNG plant scenario, based on the GHGenius model, would actually result in additional CO_2e emissions relative the average global LNG plant GHG emissions factor.



Source: GLOBE Advisors

Figure 29: Annual GHG emissions impact of having BC natural gas replace natural gas supplied by natural gas with the global average GHG emissions footprint under the *Full Natural Gas Switching* scenario (assuming LNG production of 88 mmtpa).

[19] **Note to reader:** Marine transportation GHG emissions are not included in this comparison as these vary based on the consumer market and global supplier. However, the difference in transportation emissions between global suppliers is relatively small, particularly when compared with the full life cycle emissions.

CONCLUSIONS

In developing this natural gas impact model, GLOBE Advisors examined BC's entire natural gas value chain from the wellhead to the industrial customer. A fundamental question is "will the development and export of LNG, originating in BC and exported to overseas markets, result in an overall increase or decrease in global GHG (CO_2e) emissions?"

The answer to this question depends largely on the extent that BC natural gas replaces coal power. In fact, the IEA's Chief Economist rejected calls for British Columbia to forgo the production and export to Asia of LNG due to concerns that the province would not meet its own GHG reduction targets, referencing that growing LNG imports in China and elsewhere could reduce the need for coal-fired electricity, leading to a global reductions in carbon dioxide emissions.[20]

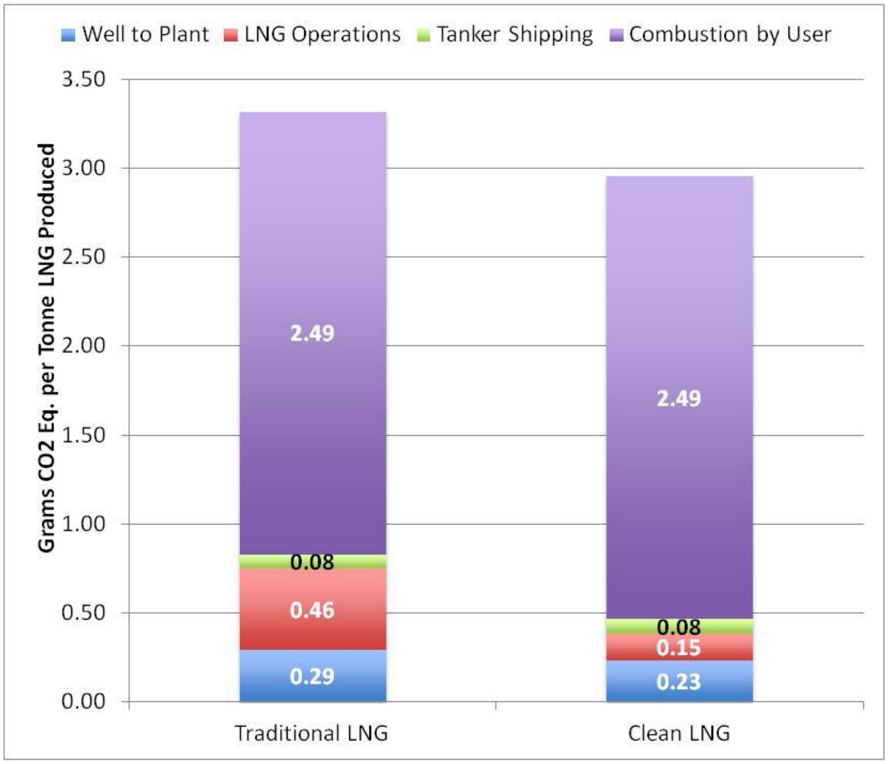
The full life cycle GHG emissions from wellhead in BC to overseas customers ranges from 2.95 tCO_2e / tLNG produced to 3.32 (as shown in Table 4 below).

Table 4: Full life cycle GHG emissions for the overseas export and consumption of BC natural gas to Asian markets for both "traditional" and "clean" LNG plant operations.

	"Traditional" LNG Plant GHG Emission Rate (tCO_2e / tLNG)	**"Clean" LNG Plant GHG Emission Rate** (tCO_2e / tLNG)
Exploration & Wellhead		
Fuel distribution and storage	0.07	0.06
Fuel production	0.07	0.06
Feedstock recovery	0.09	0.08
Gas leaks and flares	0.07	0.04
Subtotal	**0.29**	**0.23**
LNG Plant		
CO_2, H_2S removed from NG	0.12	0.01
Liquefaction at LNG Plants	0.33	0.14
Subtotal	**0.46**	**0.15**
Well-to-Water Upstream with		**0.38**
Well-to-Water with no CCS	**0.75**	**0.50**
Tanker Emissions	**0.08**	**0.08**
Customer Combustion Emissions	2.49	2.49
Total Life Cycle Emissions with CCS		**2.95**
Total Life Cycle Emissions without CCS	**3.32**	**3.07**

[20] Article from The Globe and Mail, November 17, 2013. See: http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/oil-sands-not-a-major-source-of-climate-change-says-iea-economist/article15480326/

Figure 31 below illustrates the full life cycle GHG emission factors for both a “traditional” LNG plant (based on GHGenius value of 0.75 tCO_2e / tLNG) and for an LNG plant in BC using the “cleanest” production factor of 0.38 tCO_2e / tLNG, assuming 88 mmtpa of LNG is exported to Asia. The vast majority of these full life cycle GHG emissions occur when the customer burns the gas to produce electricity.



Source: GHGenius and GLOBE Advisors

Figure 31: Full life cycle GHG emission factors for 88 mmtpa of LNG exported from BC to Asia, produced by a “traditional” LNG plant and a plant using current “clean” production best practices.

The scenarios discussed in this report provide three examples of where, on a full life cycle basis, there is a net reduction of global GHG emissions due to either replacing thermal coal in Asian markets, or from the replacement / substitution of LNG coming from other global suppliers (assuming the global average for life cycle GHG emissions) with LNG produced in BC under the “clean” plant assumptions.

Based on its review of secondary sources and global trends in energy demand and supply, GLOBE Advisors feels that the most realistic outcome for natural gas exported from BC to Asian markets will be a combination of switching out / replacing both thermal coal *and* natural gas product from other global suppliers (with the exception of Malaysia where it may go primarily to replacing diesel). GLOBE believes that a high proportion of BC LNG exports to Asia can realistically replace existing or planned coal power.

In the case where it acts as a substitute for natural gas from other global suppliers, it is particularly important to consider whether or not the upstream life cycle GHG emissions for the supply of natural gas coming from other global markets (i.e., shale and coal bed plays in Russia, China, Australia, and elsewhere) and, in some cases the related LNG plant facilities, is more or less carbon intensive than the natural gas being exported from British Columbia. This is a difficult question to answer, as BC has not yet built LNG plants and the GHG emissions described in this report are only hypothetical at this stage.

Based on comparing the GHGenius and GREET models, BC has the potential for lower per unit upstream emissions than many parts of the world and, given the province's predominantly hydro-powered electricity grid, may be able to power much of the proposed LNG plant operations using a clean electricity mix. In addition, the well-to-waterline GHG emissions target rate proposed in this report of 0.38 tCO_2e / tLNG produced is close to the GHG emissions rate of select "best-in-class" LNG plants around the world (in Australia and Norway), albeit these plants are not comparable in nature since they mostly source their natural gas from deep sea locations.

An important issue on the level of upstream emissions in BC pertains to the amount of carbon dioxide gas that is embedded in the methane. The Pacific Institute for Climate Solutions (PICS) reported that "raw natural gas extracted from shale deposits in the Horn River Basin contains approximately 11-12% CO_2, considerably higher than the average content of 2-4.5% for BC's conventional natural gas reservoirs (NEB, 2009b; CAPP, 2004; CAPP, 2010) and the even lower 1% CO_2 content of the Montney fields (based on an update to the GHGenius model). Typically, commercial gas sold to market customers can contain no more than 2% CO_2 to ensure adequate heating value and for pipeline restrictions. When excess CO_2 is removed at natural gas processing facilities, it is usually vented to the atmosphere".

This information suggests that carbon capture and storage (CCS) may play an important role to keeping BC's natural gas GHG footprint as clean as the global best standard. Effective CCS technology requires suitable storage locations (e.g., depleted wells), with the CO_2 being transported to these storage facilities if none are near the processing and LNG facilities. This could add substantially to project costs. Alternatively, innovative technologies could be employed to convert the CO_2 to usable carbon-based products (see discussion on innovative "carbon recycling" technologies on page 21).

At the end of the day, the total net benefit that will come from exporting BC's natural gas to Asian markets in terms of its ability to reduce overall global GHG emissions will depend largely on how much coal is replaced. Where it serves as a substitute for natural gas from other sources, the well-to-waterline GHG emissions footprint would have to be kept lower than the global average of 0.52 tCO_2e / tLNG in order to maintain a net benefit. For BC, this will mean achieving better plant production than the current "industry standard" by applying renewable power where possible, best-in-class / efficient technology such as electric drive compressors, and preferably CCS solutions.

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Appendix A: Methodology

GLOBE Advisors worked with the British Columbia life cycle module of the GHGenius Model, which has been developed for Natural Resources Canada. GHGenius focuses on the life cycle assessment (LCA) of current and future fuels for transportation and stationary applications. A summary for natural gas and other fuels is shown Table A1. Table A1 shows that gasoline and highway diesel emit substantially more CO2 equivalent GHG emissions than any of the natural gas categories.

Table A1: CO2-Equivalent Emissions per Unit of Energy Delivered to End Users by Stage and Feedstock/Fuel Combination (Grams per GJ, British Columbia 2010

	Gasoline	Hwy diesel	LPG	CNG	NG to	NG to	NG to	NG to	NG to
	Oil	Oil	NG	NG	Power	Industry	Commerce	NG pipeline	NG field
Fuel dispensing	19.1	19.5	19.6	183.9	0.0	0.0	0.0	0.0	0.0
Fuel distribution and storage	402.5	411.2	661.5	1,275.6	1,144.1	1,144.1	1,271.2	444.9	0.0
Fuel production	10,385.5	7,909.0	2,566.7	1,345.8	1,339.3	1,341.1	1,341.2	1,339.0	1,338.8
Feedstock transmission	78.8	80.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feedstock recovery	11,936.5	12,194.0	1,729.5	1,653.6	1,645.7	1,647.9	1,646.3	1,644.1	1,644.1
Land-use changes, cultivation	427.5	427.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas leaks and flares	2,190.4	2,185.7	636.3	2,378.0	654.4	1,133.5	1,149.8	564.9	508.0
CO2, H2S removed from NG	0.0	0.0	638.3	641.2	638.1	638.9	639.0	637.9	637.8
Emissions displaced	-189.7	-189.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	25,250.6	23,037.8	6,251.9	7,478.0	5,421.6	5,905.6	6,047.5	4,630.8	4,128.7

Source: GHG Genius BC Model

Table A2 illustrates GHG emissions on a per centage basis. Note that gas leaks and flares are proportionally much higher for the natural gas categories than for gasoline and highway diesel.

Table A2: Per centage of CO2-Equivalent Emissions per Unit of Energy Delivered to End Users by Stage and Feedstock/Fuel Combination (Grams per GJ, British Columbia 2010

	Gasoline	Hwy diesel	LPG	CNG	NG to	NG to	NG to	NG to	NG to
	Oil	Oil	NG	NG	Power	Industry	Commerce	NG pipeline	NG field
Fuel dispensing	0.1%	0.1%	0.3%	2.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Fuel distribution and storage	1.6%	1.8%	10.6%	17.1%	21.1%	19.4%	21.0%	9.6%	0.0%
Fuel production	41.1%	34.3%	41.1%	18.0%	24.7%	22.7%	22.2%	28.9%	32.4%
Feedstock transmission	0.3%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Feedstock recovery	47.3%	52.9%	27.7%	22.1%	30.4%	27.9%	27.2%	35.5%	39.8%
Land-use changes, cultivation	1.7%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fertilizer manufacture	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Gas leaks and flares	8.7%	9.5%	10.2%	31.8%	12.1%	19.2%	19.0%	12.2%	12.3%
CO2, H2S removed from NG	0.0%	0.0%	10.2%	8.6%	11.8%	10.8%	10.6%	13.8%	15.4%
Emissions displaced	-0.8%	-0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Source: GHG Genius BC Model

The GHG emission intensity ratios that were applied in this report were derived from the GHGenius lifecycle model that was developed specifically for British Columbia by Natural Resources Canada. The lifecycle results from the wellhead to the waterline were lower than what has been reported by some other reports, including Clean Energy Canada and the Pembina Institute. Subsequently, GLOBE Advisors ran its production numbers through the American GREET lifecycle model as a point of comparison.

The following Figure illustrates and compares the GHG emission results based on both the British Columbia GHGenius model and the American GREET model. The GREET GHG emissions per tonne ratios are slightly higher than the GHGenius rates.[21]

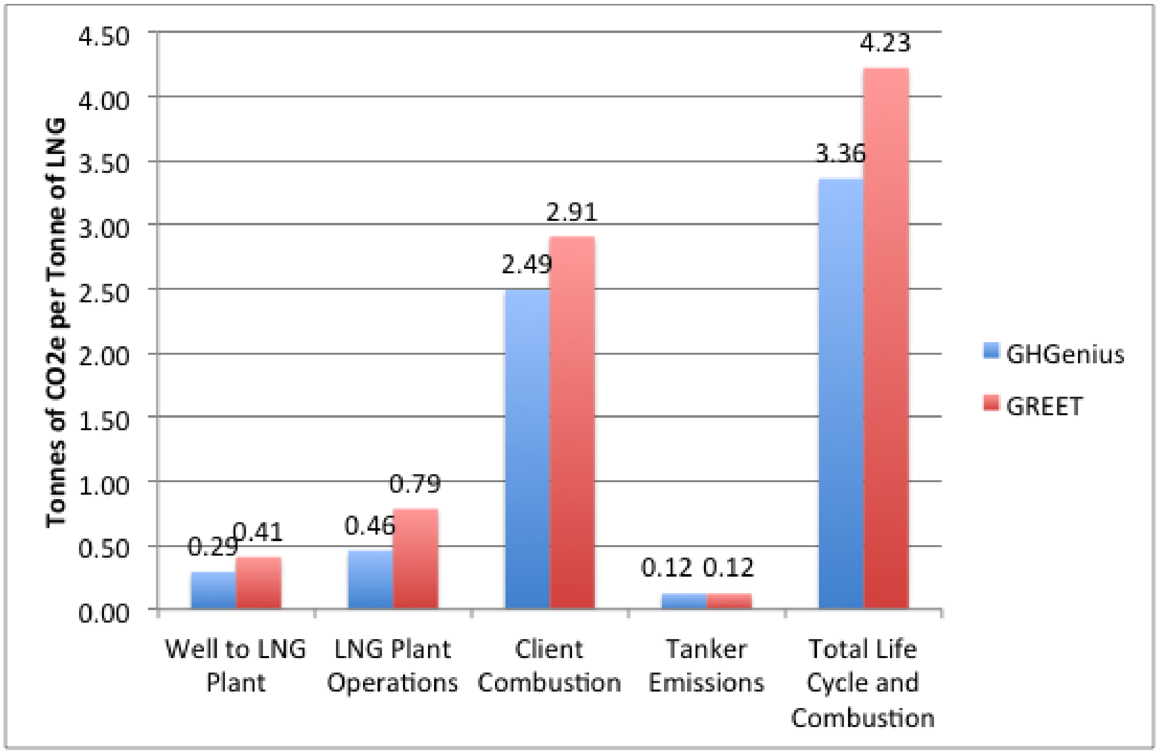


Figure A1: GHG Ratios, CO2 Equivalent Tonnes per Tonne of LNG for GHGenius and GREET Models

[21] The tanker emission factor was based on neither GHGenius nor GREET, but it is included in the chart in order to show complete life cycle emissions.

Attachment 60.6

PEMBINA institute

Limiting methane pollution from B.C.'s gas sector

A prime opportunity for stronger action on upstream emissions

by Maximilian Kniewasser | May 2018

Summary

Stronger action to reduce methane pollution from British Columbia's natural gas sector and prospective liquefied natural gas (LNG) industry is essential to meeting B.C.'s climate targets.

Methane emissions represent one of the most effective and cost-efficient opportunities to reduce carbon pollution in support of meeting climate targets for B.C.'s industrial sector. Current regulations to reduce methane emissions by 45% are estimated to cost just \$1.70/t-CO_2e. This suggests more cost-effective opportunities remain.

More ambitious regulations are already in place in several U.S. states that essentially eliminate venting from routine operations across the gas supply chain.

Fulfilling the B.C. government's commitment to balance LNG development with B.C.'s climate targets will require increasing ambition on methane emissions. Ambition should reflect best practices and the government's commitment to price fugitive emissions.

Context

The British Columbia government has made strong commitments with respect to getting B.C. back on track to meeting our climate targets, establishing sectoral goals, and developing an energy road map to transition B.C. to low-carbon industries.

While the government has signalled support for developing a liquefied natural gas (LNG) industry, it has also pledged to ensure LNG development is consistent with B.C.'s climate targets. B.C.'s current climate plan does not achieve this, and the recently announced LNG framework does not include any new measures to reduce emissions.

Additional measures to lower carbon pollution across the LNG supply chain are necessary. Upstream development offers a particularly impactful opportunity to reduce carbon pollution in the form of methane.

Considerations

Methane is one of the lowest-cost emissions reduction opportunities in the entire economy because:

- Leaked methane is a powerful greenhouse gas and reducing this pollutant has an outsized impact.
- Conserving methane eliminates waste of a sale product and therefore increases the amount of commercial product available for sale.

Maximizing the reductions from this low-cost opportunity will ensure cost impacts to industry are limited, and B.C. achieves its emissions targets at the lowest overall cost. Reducing methane emissions by 45% costs just \$1.70/t-CO_2e in B.C., according to research by the Pembina Institute.[1] For comparison, the costs of electrifying power processes either upstream or at terminals — the other most significant opportunity to reduce emissions — is estimated to cost around \$100/t-CO_2e.[2]

There is an expectation the carbon tax will be applied to methane emissions from B.C. gas operations, based on the government's commitment to expand the carbon tax to cover fugitive emissions. As such, the \$50/t-CO_2e level announced for 2021 should be seen as a common baseline for pricing and regulation applied to these emissions. This will ensure the gas sector faces the same stringency as other businesses and all British Columbians.

The recent *World Energy Outlook* by the International Energy Agency (IEA) shows that, in a 2°C world, we need to reduce methane emissions from oil and gas operations by 70% to 75%. In practice, according to the IEA, this means implementing "essentially all technically feasible solutions." Considering the technologies available across the supply chain today, this can be interpreted as achieving *no routine venting* from operations.

Current measures to reduce methane emissions by 45% in B.C., Canada, and across most of the United States fall short of the level identified by the IEA. The Pembina Institute estimates the costs of achieving a 45% reduction in B.C. is just \$1.70/t-CO_2e, substantially below the \$50/t-CO_2e price committed to by the government. For comparison, the cost of achieving a 70% to 75% methane reduction, as per IEA findings,[3] is estimated at \$20/t-CO_2e, also well below the \$50/t-CO_2e level.[4]

[1] ICF International, *Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries* (Environmental Defense Fund and Pembina Institute, 2016). http://www.pembina.org/pub/economic-analysis-of-methane-emission-reduction-opportunities-canadian-oil-and-natural-gas

[2] This considers fuel costs and carbon costs, and assumes equipment and other operating costs are generally comparable between natural gas and electric power equipment.

[3] International Energy Agency, *World Energy Outlook 2017* (2017).

[4] Based on preliminary analysis by the Pembina Institute, assuming a gas price in B.C. of \$2.50 per Mcf.

More ambitious methane control is already viable, both financially and technologically. Best practices are already happening in several U.S. states; B.C. has an opportunity to build on this leadership. For example, California mandates no venting from pneumatic pumps and devices, Colorado requires implementation of no-bleed pneumatic controllers if electricity is available, Colorado also requires controlling wet seal emissions from compressors by 95%, and several states require more frequent leak detection and repair (quarterly inspections). In fact, while spread across several jurisdictions, the regulations already in place today essentially eliminate routine venting from production, processing, and transportation. California is a leading jurisdiction that requires elimination of most venting emissions from new and existing sources and requires more ambitious leak detection and repair (LDAR), with costs estimated at $40/t-$CO_2$e or below[5] (with significant reduction opportunity well below this[6]).

Innovation of new technologies for detecting and reducing methane emissions is occurring at a rapid pace, and will continue to drive costs even lower. For example, a paradigm shift is occurring in the availability of low-cost sensors capable of detecting methane concentration in ambient air. [7] Coupled with the availability of inexpensive wireless communication and networking capabilities, this now allows for continuous monitoring at a fraction of the price of traditional infrared surveys. This will help identify leaks in a more timely manner at a lower cost. This is just one example of how technology and innovation is driving cost reductions and increasing the potential to reduce methane emissions from oil and gas operations.

Current industry practices are inconsistent with B.C.'s climate targets. Oil and gas operations in Canada often use out-dated equipment that results in much higher emissions than necessary. For example, a recent survey in Alberta found 95% of pneumatic equipment is leaking methane into the air, even though clean alternatives are readily available. (See Appendix 2; similar data is not available for B.C.)

The opportunity to reduce B.C.'s methane emissions is greater than realized. According to official reporting, methane accounts for about 20% of total gas sector emissions. However, data about methane emissions is poor, and emissions are likely much higher in total. For example, research shows that methane emissions in the Montney Formation are at least 2.5 times higher

[5] The Pembina Institute's analysis does not include measures that reduce emissions by less than 1% of total expected reductions, which are outliers at the top and bottom of the cost spectrum. Source: California Air Resources Board, *Public hearing to consider the proposed regulation for greenhouse gas emission standards for crude oil and natural gas facilities* (2016).

[6] For example, switching to no bleed pneumatic devices and pumps for new and existing facilities achieves almost a quarter of total reductions at a cost estimated at just $3/t-$CO_2$e.

[7] Ramboll Environ, *Technology Assessment Report: Air Monitoring Technology Near Upstream Oil and Gas Operations* (Environmental Defense Fund, 2017). https://www.edf.org/sites/default/files/Ramboll-report.pdf

than reported.[8] Recent findings in Alberta are even worse (see Appendix 2). Through stronger action on methane, more can be achieved to get B.C. back on track to its climate targets.

While much focus is on the opportunity to reduce emissions from LNG and associated upstream development,[9] reducing methane is important for the broader natural gas sector. Natural gas is already B.C.'s biggest source of industrial emissions, and it will continue to play an outsized role in B.C.'s emissions profile in the long term. As such, effectively reducing methane is critical to achieving the government's commitment to move industry to zero-carbon energy, whether LNG proceeds or not.

Fugitive emissions are tough to measure accurately, and we currently do not have the necessary reporting infrastructure in place. This will prevent us from broadening the carbon tax to apply to fugitives across the natural gas supply chain in the short-term. As such, we will remain in a regulatory environment for at least the short to medium term.

Recommendations

Based on our analysis, we believe the B.C. government should:

1. Convene key stakeholders in the short term to identify the right level of ambition on methane reductions needed to fulfill the government's commitment to balance LNG development with its climate targets. Subsequently, convene a multi-sector technical working group to help in the design and implementation of the recommendations.
2. Move quickly to implement up-to-date measurement and reporting infrastructure to be able to put a price on fugitives as per government's commitment. In the meantime, regulate methane emissions to a level in-line with the stringency of \$50/t-CO_2e and/or best practices.
3. Set the baseline for reductions as *no routine venting* from new operations in the short term. Increase ambition on existing operations to reflect best practices and/or current best regulations, with a particular focus on providing facilities with electricity to enable transition to no routine venting.
4. Implement quarterly LDAR along all facilities. Require continuous monitoring for all new facilities and implement continuous monitoring for already existing facilities that are potential high-emissions sources, such as processing plants and pipeline compressor stations.

[8] Atherton et al., *Mobile measurement of methane emissions from natural gas developments in northeastern British Columbia, Canada,* (2017). https://doi.org/10.5194/acp-17-12405-2017

[9] See: Dylan Heerema and Maximilian Kniewasser, *Liquefied Natural Gas, Carbon Pollution, and British Columbia in 2017* (Pacific Institute for Climate Solutions and Pembina Institute, 2017). http://www.pembina.org/pub/lng-carbon-pollution-bc

Conclusion

Any significant LNG development will put material upward pressure on B.C.'s carbon pollution and make meeting our climate targets increasingly challenging. Therefore, achieving the above should be seen as a prerequisite to making good on the government's promise to ensure LNG development is consistent with B.C.'s climate commitments.

Appendix 1. Reasons to take strong action on methane emissions

Highly effective: Tackling methane is one of the most effective ways to reduce carbon pollution from the natural gas sector.

Economically efficient: As one of the lowest-cost opportunities, methane emissions reductions will limit cost impacts to producers and ensure that B.C. achieves its climate targets at the lowest cost.

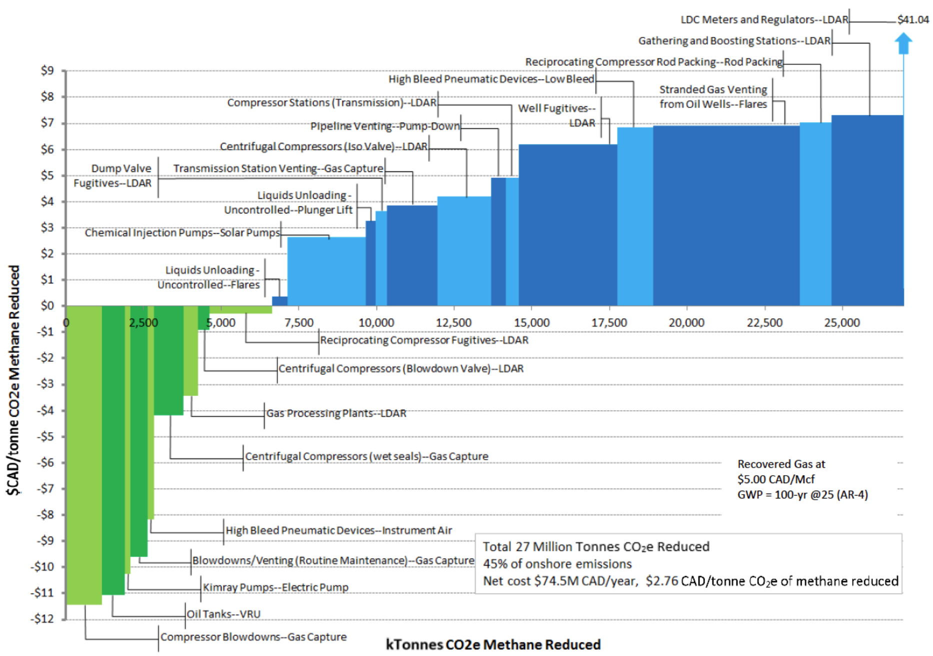
Equitable: Methane action ensures the gas sector does its fair share to reduce carbon pollution. Currently, approximately 40% of gas sector emissions are not priced, while other businesses and ordinary British Columbians pay for all of their carbon emissions.

Achievable: Leading U.S. states are already requiring the implementation of technologies that essentially eliminate routine methane venting across the supply chain, showing that stronger methane action is already technologically and financially feasible.

Promoting resiliency: Addressing methane emissions will future-proof investments, so B.C.'s gas sector will be able to compete as the world transitions to low-carbon energy sources.

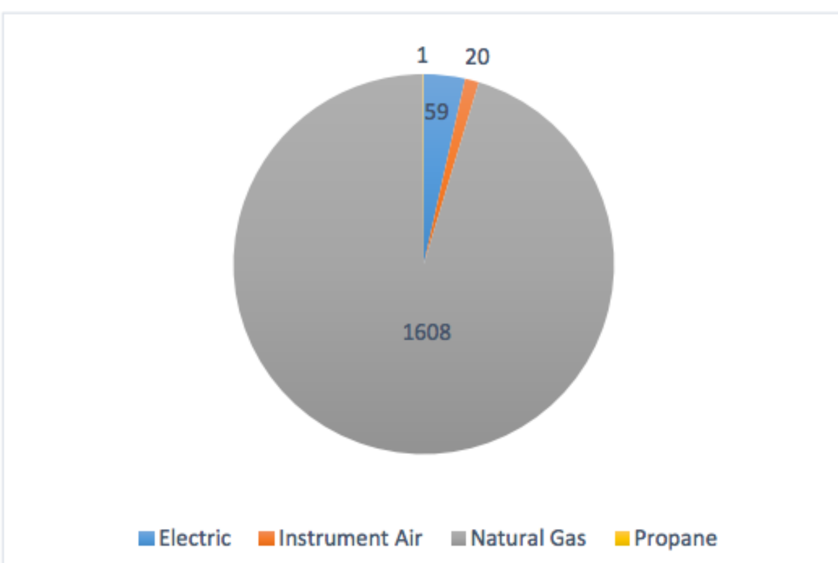
Appendix 2. Charts

Figure 1. Marginal abatement cost for methane reductions in Canada



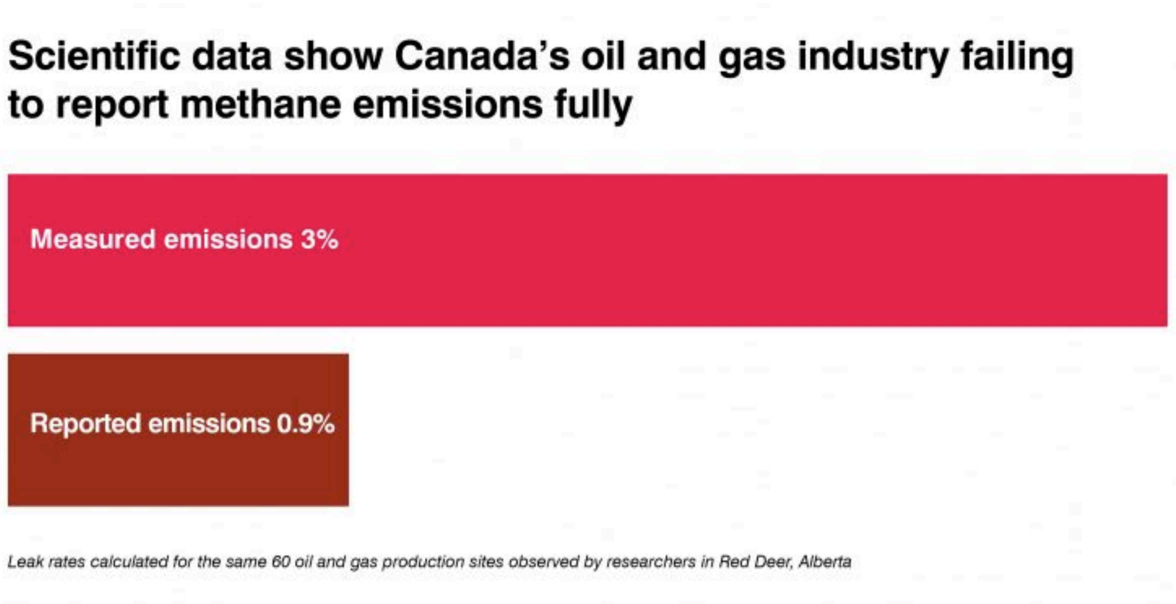
Source: ICF International, *Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries* (Environmental Defense Fund and Pembina Institute, 2016). http://www.pembina.org/pub/economic-analysis-of-methane-emission-reduction-opportunities-canadian-oil-and-natural-gas

Figure 2. Types of pneumatic device drivers in Alberta



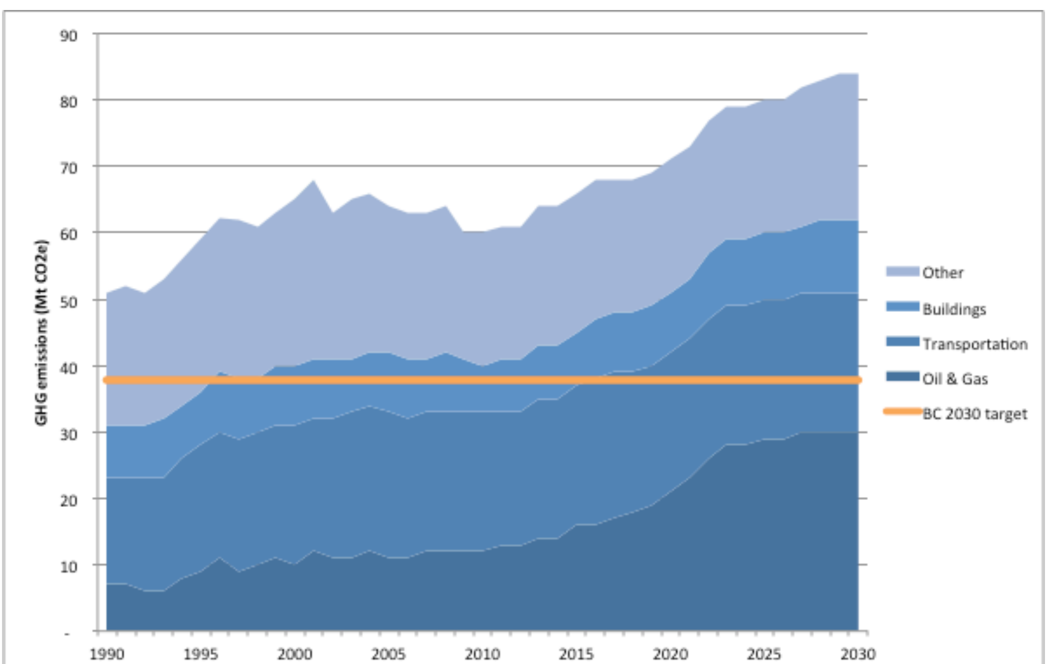
Source: Greenpath Energy Ltd., *Greenpath 2016 Alberta Fugitive and Vented Emissions Inventory Study* (2016). http://www.greenpathenergy.com/wp-content/uploads/2017/03/GreenPath-AER-Field-Survey-Results_March8_Final_JG.pdf

Figure 3. Methane emissions from wellheads in Red Deer, Alberta



Source: Environmental Defence, "New study finds methane gas emissions are 15 times higher than reported by industry" (March 22, 2018). https://environmentaldefence.ca/2018/03/22/study-finds-methane-emissions-15-times-higher-reported/

Figure 4: B.C. emissions forecast by sector



Source: Government of Canada, *Canada's Second Biennial Report on Climate Change* (2018). Note: The report assumes 19 Mtpa of LNG, with an emissions intensity of 0.19t-CO_2e/t-LNG. Oil and gas sector emissions in 2030 are forecasted at 30 Mt, or 79% of B.C.'s 2030 target.