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Calibrating Liquefied Natural Gas Export Life Cycle Assessment:
Accounting for Legal Boundaries and Post-Export Markets

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Abstract

The climate impact of liquefied natural gas (LNG) export from North America is one of the most pressing questions for Canadian and world energy policy today. This paper performs the first life cycle assessment (LCA) of the greenhouse gas emissions from LNG exports from Canada, assuming that importing countries use the natural gas for electricity generation. It shows that the climate impact of LNG depends on where it is sent. If LNG from Canada displaces electricity in coal-dependent countries, it will likely lower global greenhouse gas emissions. If it displaces electricity from countries that rely on low carbon sources such as hydroelectricity and nuclear power, it will likely increase global emissions. A broad suite of policy and regulatory measures is discussed for reducing greenhouse gas emissions due to LNG export, from life cycle regulation to facility-level emissions management.

List of Abbreviations

AB	Alberta
ANL	Argonne National Laboratory
AR4	IPCC Fourth Assessment Report
BC	British Columbia
BCM	billion cubic metres
bcf/d	billion cubic feet per day
BP	British Petroleum
CAPP	Canadian Association of Petroleum Producers
CCCL	Columbia Center for Climate Change Law
CFR	US Code of Federal Regulations
CH_4	methane
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CO_2e/MWh	carbon dioxide equivalent per megawatt hour
CSP	concentrated solar power
DOE	US Department of Energy
EIA	US Energy Information Administration
EIO	economic input output
EPA	US Environmental Protection Agency
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
gCO_2e/MJ	grams of carbon dioxide equivalent per mega joule
GHGRP	Greenhouse Gas Reporting Program
GIIGNL	International Group of Liquefied Natural Gas Importers
GPS	Global Perspectives & Solutions
GREET	Greenhouse gases, Regulated Emissions, and energy use in Transportation
GWP	global warming potential
HHV	higher heating value

IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
JEPIC	Japan Electric Power Information Center
JISEA	Joint Institute for Strategic Energy Analysis
kg	kilogram
kt	kilotonne
LCA	life cycle assessment
LEM	Life cycle Emissions Model
LNG	liquefied natural gas
MMBtu	million metric British thermal units
MMTPA	million metric tonne per annum
MOEA	Ministry of Economic Affairs of Taiwan
N. Miles	nautical miles
N_2O	nitrous oxide
NESHAP	National Emission Standards for Hazardous Air Pollutants
NETL	US National Energy Technology Laboratory
NG STAR	Natural Gas STAR
NSPS	New Source Performance Standards
OCDE	Organisation for Economic Co-operation and Development
OIES	Oxford Institute for Energy Studies
PERF	Petroleum Environmental Research Forum
PV	photovoltaic
TCEQ	Texas Commission on Environmental Quality
TWh	terawatt hour
UK	United Kingdom
US	United States

1. Introduction

In coming years, natural gas is slated to meet an increasing share of the world's burgeoning energy needs. At the same time, the world is faced with the pressing challenge of climate change. These twin developments have pushed the expansion of a global liquefied natural gas (LNG) industry to the heart of global energy conversations. Will North American LNG, enabled by the shale revolution, displace coal power in developing nations and complement renewable energy to help solve economic, energy and environmental challenges? Or are LNG projects simply another risky long-term investment in fossil fuels that will inevitably harm the climate or, if stringent carbon regulations are adopted, its investors? This paper begins to answer these questions by looking at the net greenhouse gas impact of LNG exports from Canada, considering whether LNG is likely to displace higher emissions sources of power such as coal, and exploring what Canadian regulators can do to minimize the net impact of LNG.

This paper performs a life cycle assessment (LCA) of greenhouse gas emissions from Western Canadian LNG exports. This is a crucial analysis for current energy policy because British Columbia (BC) has committed to exporting LNG and promised that its LNG exports will be the "cleanest LNG in the world [on a] life cycle basis."[1] LCA is a quantitative tool used to estimate the environmental burdens from a product or process over its entire life cycle from materials extraction to waste disposal. In this case, the environmental burden in question is the magnitude of greenhouse gas emissions. That is, this assessment considers more than merely the greenhouse gas emissions from burning a fuel for energy. Instead, emissions associated with all stages of a fuel's supply chain are determined. For natural gas, this includes production, processing, mid-stream infrastructure operations, liquefaction, transport, regasification and end use. Clearly, for such a broad study, data can be uncertain. As a result, our approach encompasses four objectives: (1) to undertake an assessment of the state of greenhouse gas emissions data for the Canadian natural gas supply chain, (2) to examine LNG export market potential, landed natural gas prices and current offtake agreements, (3) to determine first-order estimates for the greenhouse gas implications of LNG export for electricity generation in potential markets, and (4) to discuss the regulatory implications for the Canadian federal and provincial governments considering the implications of the analysis and uncertainty in the data. We conclude with recommendations for each objective to fill data gaps and push forward a research agenda.

This LCA is unique in two important respects. First, it is calibrated for boundaries on BC and Canada's legal jurisdiction — identifying greenhouse gas emissions that occur within Canada and in export markets. Second, the paper examines the full greenhouse gas impact of LNG exports by examining what sources of electricity LNG may displace in

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[1] Government of British Columbia, *British Columbia's Natural Gas Strategy: Fuelling B.C.'s Economy for the Next Decade and Beyond* (2012), online: <http://www.gov.bc.ca/ener/popt/down/natural_gas_strategy.pdf>.

the target markets for Canadian exports. The suggestion that LNG will displace coal-fired power in importing markets has been one of the key environmental arguments for LNG exports. This paper addresses that argument by aggregating data on LNG pricing and identifying potential export markets for Western Canada's LNG, and estimating electricity sector emissions in these target markets to determine whether displacing those sources with LNG from Canada would lower worldwide greenhouse gas emissions. The assumption here is that natural gas will be used for electricity.

The LCA was performed in two stages: an assessment of upstream emissions followed by an assessment of potential downstream emissions displacement. First, the upstream components of the LCA were examined and compared to existing datasets to determine potential gaps and areas for future research. Available data on greenhouse gas emissions from natural gas production, processing and transmission in BC and Alberta (AB),[2] were combined with data for liquefaction from a United States (US) Department of Energy/National Energy Technology Laboratory (DOE/NETL) study of LNG emissions[3] to present a first-order full life cycle estimate of greenhouse gas emissions from Canadian LNG. Because the upstream data were incomplete and had to be supplemented with estimates, we provide recommendations on how to improve national and provincial estimates, including enhanced measurement and liquefaction estimates specific to the region as they become available. In the second step, we estimate the net impact of LNG exports for the electric sector through identifying potential export markets, developing first-order estimates for emissions displacement, and providing recommendations for improving these estimates.

This paper brings clarity to the continuing debates on the climate impact of LNG, by showing the circumstances in which it may create a net climate benefit. It provides BC with the tools to assess whether it is achieving its goal of reducing greenhouse gases on a life cycle basis. Finally, it can serve as an example for future studies by integrating scientific and regulatory approaches to life cycle policies — providing regulators with both the information and the tools to accomplish their climate goals.

2. Life Cycle Assessment of LNG Export for Electricity Generation: Upstream Emissions

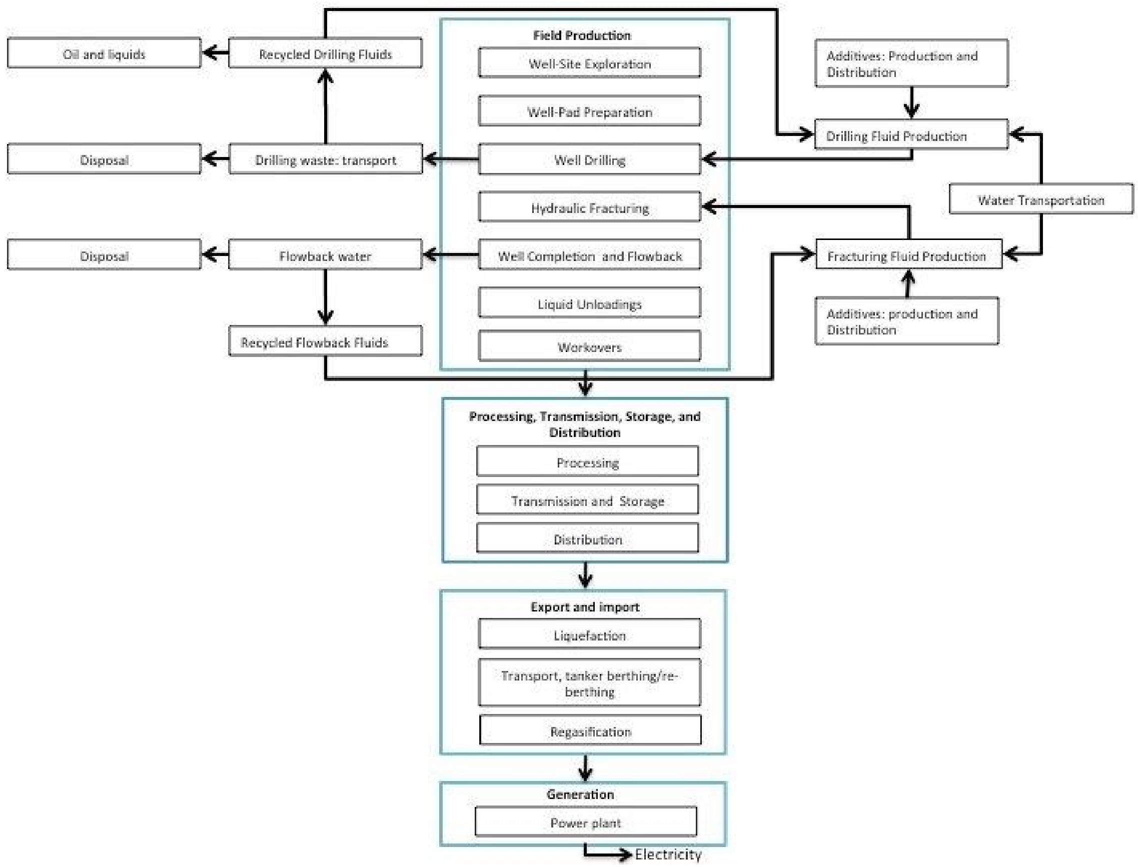
This section serves to meet the first objective, which is to undertake an assessment of the state of greenhouse gas emissions data for the Canadian natural gas supply chain. To achieve this objective, existing US life cycle assessment (LCA) studies were reviewed,

[2] Environment Canada, "Reported Facility Greenhouse Gas Data — Downloadable Emissions Data [MS Excel version, 1.90 MB]: Complete set of emissions data by facility from 2004-2012", online: <http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=8044859A-1>.

[3] TJ Skone et al, Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from United States, Report No DOE/NETL-2014/1649 (Pittsburgh, PA: DOE/NETL, 2014).

Canadian data were compiled, and the results were compared. From this, an estimate for Canadian upstream emissions associated with LNG exports was determined, complete with an investigation of the limitations of the available data. LCAs of LNG export for electricity generation will have system boundaries that capture some portion of the components in Figure 1.

Figure 1: Illustrative schematic of the life cycle of LNG that is exported for use in electricity generation



The different system boundaries that are applied across studies (as well as different methods) remain a key challenge in determining how to develop consistent LCAs so that both regional differences and effectiveness of control technologies can be investigated.

The processes outlined in Figure 1 can be broadly categorized in to nine life cycle stages: production, processing, transmission and storage, liquefaction, LNG transport, tanker berthing and deberthing, regasification, power plant operations, and electricity distribution. These life cycle phases are described in Table 1. Even within these stages, the system boundaries can differ and the sophistication of the measurements or estimates may vary between studies.

Table 1: Life cycle stages that may be considered in LCA of LNG export

Life cycle Stage	Description
Production	Construction, drilling, fracturing and completion
Processing	Flaring, lease energy (that used on site), plant emissions, vented CO_2, fugitive well emissions, fugitive plant emissions, workovers and liquids unloadings
Transmission and storage	Compression and fugitive emission
Liquefaction	Liquefaction process at the liquefaction facility
LNG transport	LNG transport from export terminal to import terminal in destination country
Tanker berthing and deberthing	Loading and unloading of LNG tanker
LNG regasification	Regasification of LNG to gaseous state
Power plant operations	Use of natural gas in power plant for electricity generation
Electricity distribution	Transmission and distribution of electricity

In this section, we focus first on the upstream component of existing studies, but then expand out to examine the life cycle implications of LNG. Later sections of the report will investigate alternative markets that may be serviced with Canadian LNG.

2.1 State-of-the-Art of Natural Gas LCA Studies

In our review, eleven existing studies from the US were examined[4] and results were compared to existing Canadian data.[5] Results were found to be inconsistent across studies

[4] R Howarth, R Santoro & A Ingraffea, "Methane and the greenhouse-gas footprint of natural gas from shale formations" (2011) 106:4 Climatic Change 679-690; T Stephenson, JE Valle & X Riera-Palou, "Modeling the Relative GHG Emissions of Conventional and Shale Gas Production" (2011) 45:24 Environmental Science &Technology 10757-10764; CL Weber & C Clavin, "Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications" (2012) 46:11 Environmental Science & Technology 5688-5695; A Venketash et al, "Uncertainty in Life Cycle Greenhouse Gas Emissions from United States Natural Gas End-Uses and its Effects on Policy" (2011) 45:19 Environmental Science & Technology 8182-8189; M Jiang et al, "Life Cycle Green House Gas Emissions of Marcellus Shale Gas" (2011) 6 Environ Res Lett 034014 1-9; M Fulton et al, *Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal* (Frankfurt, Germany: Deutsche Bank Group, 2011); J Logan et al, *Natural Gas and the Transformation of the US Energy Sector: Electricity*, Technical Report NREL/TP-6A50-55538 (Golden, CO: Joint Institute for Strategic Energy Analysis [JISEA], 2012); A Burnham et al, "Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum" (2012) 46 Environmental Science & Technology 619-627; Argonne National Laboratory (ANL), *Life-Cycle Analysis of Shale Gas and Natural Gas*, Report No ANL/ESD/11/11 (Oak Ridge, TN: DOE, 2011); IJ Laurenzi & GR Jersey, "Life cycle greenhouse gas emissions and freshwater consumption of Marcellus shale gas" (2013) 47:9 Environ Sci Technol 4896-4903, online: <http://pubs.acs.org/doi/abs/10.1021/es305162w>; NETL, *Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production*, Report No DOE/NETL-2011/1522 (Pittsburgh, PA: DOE/NETL, 2011); and Skone et al, *ibid*.

due to differences in assumptions, co-product allocation, baselines, and system boundaries. Several key differences are outlined in Table 2. One effort focuses on making studies consistent so that comparisons can be made through using a meta-analytical procedure referred to as harmonization.[6] The results indicate that median estimates of greenhouse gas emissions from shale gas-generated and conventional gas-generated electricity are similar on the basis of an electrical output unit. The goal of this work is not to harmonize results, but rather to obtain a reasonable first-order estimate for Canadian emissions and provide direction for future research in better quantifying life cycle phases for the life cycle of LNG export from North America.

In the compilation of the natural gas greenhouse gas emissions data, the most relevant challenges for comparing Canadian facility-level reporting data are:

1. Differences in system boundaries, assumptions and baselines used by different studies to estimate greenhouse gas emissions from natural gas extraction and use.

2. Differences in reporting requirements and thresholds for BC, AB and the US, making emissions comparison difficult. BC has a reporting threshold of 10 kilotonne (kt) that applies to overall company releases[7] while AB applies a Federal reporting threshold of 50 kt per single facility.[8]

3. Some data are not completely disaggregated into meaningful segments where potential emissions reductions can be adequately investigated; for example, AB data for well drilling and completions, upstream/gathering and processing are all aggregated.

4. No uncertainties reported for data in some studies.

For a more detailed review of each study, please refer to Appendix A.

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[5] GHGenius, *infra* note 108; Environment Canada, *supra* note 2.

[6] Garvin A Heath et al, "Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation" (2014) 111:31 PNAS, online: <http://www.pnas.org/cgi/doi/10.1073/pnas.1309334111>.

[7] BC Ministry of Environment "GHG Facility Reports — Questions & Answers", online: <http://www2.gov.bc.ca/gov/topic.page?id=FBB18F75B34F4B47BBBDECE8D784B0CF>.

[8] *Alberta Environment and Sustainable Resource Development: Report on 2011 Greenhouse Gas Emissions* (May 2013), online: <http://environment.gov.ab.ca/info/library/8849.pdf>. Environment Canada. "Facility Greenhouse Gas Reporting Program", online: <http://ec.gc.ca/ges-ghg/default.asp?lang=En&n=040E378D-1>.

2.2 Assumptions and Modifications

To reach a reasonable first-order estimate for Canadian life cycle emissions, the following steps were taken. Though a reasonable estimate was obtained, additional research remains to improve the accuracy of the results.

1. For the differences in system boundaries, data from different studies were put into the segments that were most comparable. All data were converted to the same basis of gCO_2e/MJ natural gas (HHV) using the 100-year IPCC AR4 global warming potential.

2. Liquefaction emission factor data was taken from the DOE/NETL report[9] and applied to data from other studies, also accounting for the combustion factor inherent in the DOE/NETL report.[10]

3. For the segments tanker berthing & deberthing, LNG regasification, power plant operations and electricity transmission & distribution, emission factor data from the DOE/NETL[11] study was applied to all cases.

4. For the LNG transport segment, the emission factor used in the DOE/NETL report[12] was applied to the distances in Nautical miles from Kitimat, BC to the various possible export destinations. To arrive at a single LNG transport emission factor, a weighted average was calculated based on the size of the export markets (and thus the relative potential of exporting to those markets). Table 4 in Appendix B shows the LNG transport emission factors for different export markets from Kitimat, BC.

5. For the LCA using data from GHGenius, data for emissions resulting from fuel dispensing was not considered.

2.3 Comparison of Life Cycle Greenhouse Gas Emissions

In Figure 2, the life cycle greenhouse gas emissions from various studies are compared. Estimates for natural gas life cycle greenhouse gas emissions for BC and AB are lower than those of all other studies, which may reflect a variety of factors such as differences between geological basins, operational practices, reporting limitations, or measurement limitations. In Figure 2, data for well drilling and completions, upstream/gathering and processing are all aggregated. Table 2 presents the key differences across the LCAs

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[9] Skone et al, *supra* note 3.
[10] *Ibid*.
[11] *Ibid*.
[12] *Ibid*.

examined. Time horizons refer to the time scale used in calculating Global Warming Potential (GWP).

The LCAs reviewed were found to have inconsistent systems boundaries, methods, reporting requirements, study areas, and assumptions. While we provide a comparison in Figure 2, this is primarily to illustrate the differences noted in Table 2, highlighting the need to develop standardized methods to ensure studies on natural gas can be rigorously compared. While key challenges remain with the consistency of reporting standards, we use these preliminary estimates of BC LNG emissions for the basis of the rest of the report. While these data provide a basis for this first-order assessment, it must be noted that uncertainty remains in the underlying measurement data for all North American emissions.[13] Improving actual measurements must be among the priorities in future work.

3. Market Analysis and Canada's LNG Export

This section addresses the third objective of the paper which is to examine LNG export market potential, landed natural gas prices and LNG projects that currently have purchase, sale or offtake agreements. We begin by identifying proposed projects that have existing offtake agreements, and finish by assessing which markets have potential for future export.

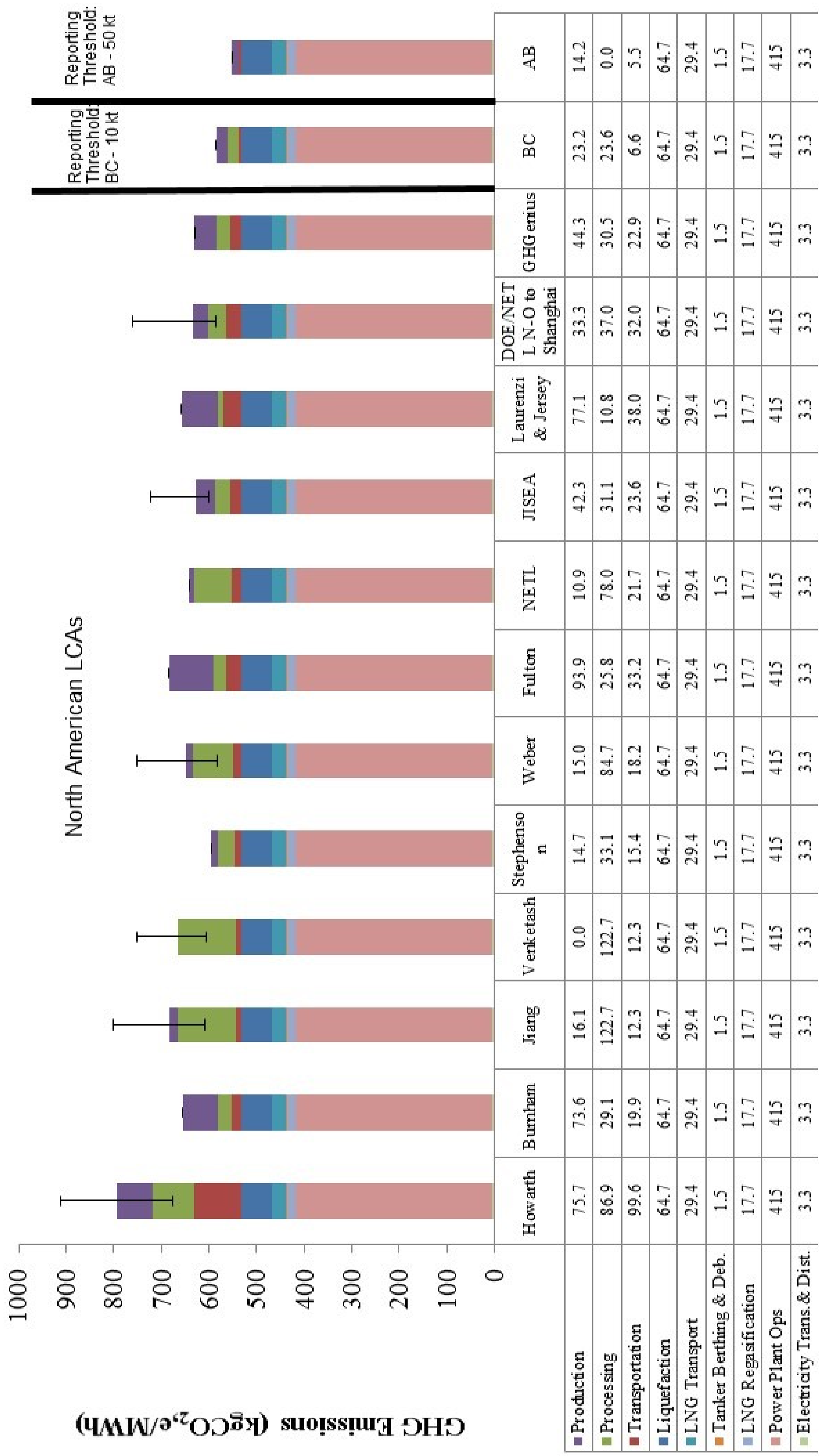
3.1 Proposed Projects and Offtake Agreements

To understand the current proposed projects and offtake agreements, a literature review was undertaken. According to the National Energy Board,[14] 19 export license applications had been submitted for LNG export from Canada as of September 5, 2014. If actually completed, the 19 projects would have an aggregate liquefaction capacity of 378 MMTPA. Start dates for some of the proposed projects are not scheduled, those with scheduled start dates would have an aggregate liquefaction capacity of 264 MMTPA by 2026, when the projects are scheduled to have been commissioned. As at the time of compilation of this report, 9 of the 19 projects, with a projected export capacity of 206 MMTPA by 2026, had been approved. Two of the remaining projects, with a projected capacity of 40 MMTPA, had incomplete status, while the remaining 8 projects, with a projected capacity of 132 MMTPA, were under review by the National Energy Board.

[13] AR Brandt et al, "Methane Leaks from North American Natural Gas Systems" (2014) 343 Science 733-735.

[14] National Energy Board, "LNG Export License Applications" (2014), online: <http://www.neb-one.gc.ca/clf-nsi/rthnb/pplctnsbfrthnb/lngxprtlcncpplctns/lngxprtlcncpplctns-eng.html>.

Figure 2: Comparison of different studies for life cycle greenhouse gas emissions of shale gas production



	Howarth	Burnham	Jiang	Venketash	Stephenson	Weber	Fulton	NETL	JISEA	Laurenzi & Jersey	DOE/NETL LNG to Shanghai	GHGenius	BC	AB
Production	75.7	73.6	16.1	0.0	14.7	15.0	93.9	10.9	42.3	77.1	33.3	44.3	23.2	14.2
Processing	86.9	29.1	122.7	122.7	33.1	84.7	25.8	78.0	31.1	10.8	37.0	30.5	23.6	0.0
Transportation	99.6	19.9	12.3	12.3	15.4	18.2	33.2	21.7	23.6	38.0	32.0	22.9	6.6	5.5
Liquefaction	64.7	64.7	64.7	64.7	64.7	64.7	64.7	64.7	64.7	64.7	64.7	64.7	64.7	64.7
LNG Transport	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4
Tanker Berthing & Deb.	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
LNG Regasification	17.7	17.7	17.7	17.7	17.7	17.7	17.7	17.7	17.7	17.7	17.7	17.7	17.7	17.7
Power Plant Ops	415	415	415	415	415	415	415	415	415	415	415	415	415	415
Electricity Trans. & Dist.	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3

Table 2: Summary of key differences across LCAs (Updated from EPRI 2013[15])

Study	Stand-alone or Review	Shale Plays	Pathways Included	Pathways Compared to Shale Gas	Time Horizon
Howarth	SA	Haynesville, Barnett, Piceance, Uinta, Den Jules	Upstream, combustion of fuel	Conventional gas, unconventional gas, diesel oil, and coal combustion	20, 100
Jiang	SA	Marcellus	Upstream, well to wire	Coal-fired electricity (IGCC and EXPC), Natural gas (NGCC)	100
Stephenson	SA	Generic	Upstream, well-to-wire	Conventional gas (average efficiency for US generators).	100
ANL	SA	Barnett, Marcellus, Fayetteville, Haynesville	Upstream, well to wire, well to wheel	Conventional natural gas (combined cycle and average efficiency for US generators) and coal-fired (pulverized coal, supercritical boilers) electricity with and without CCS, CNG to gasoline for passenger cars, CNG to diesel for buses	20, 100
Burnham	SA	Barnett, Marcellus, Fayetteville, Haynesville	Upstream, well to wire, well to wheel	Conventional natural gas (combined cycle and average efficiency for US generators) and coal- fired (pulverized coal, supercritical boilers) electricity with and without CCS, CNG to gasoline for passenger cars, CNG to diesel for buses	20, 100
Weber	R	Study dependent	Upstream, well to wire	Conventional natural gas (efficiency for steam turbine, combined cycle, boiler)	100
Fulton	R, SA	Generic, study dependent	Upstream, well to wire	Natural gas (NCC , average efficiency for US generation,) to coal-fired electricity (average efficiencies, supercritical pulverized coal)	100
NETL	SA	Barnett	Upstream, well to wire	Natural gas (NGCC, simple cycle, average fleet) and coal electricity (supercritical with and without CCS, existing pulverized, IGCC with and without CCS, average fleet)	20, 100
JISEA	SA	Barnett	Upstream, well to wire	U.S. Coal-fired power generation	100
Laurenzi	SA	Marcellus	Upstream, well to wire	U.S. Coal-fired power generation	100

[15] Andrew J Coleman, "Shale Gas and the Prism 2.0 US REGEN Model — Supplemental Project — Perspectives on a changing industry" (Presentation made at the 88th Petroleum Environmental Research Forum (PERF) Meeting on Optimizing Leveraging Opportunities through PERF Liaison Members, Richmond, CA, 5 November 2013). The LCA component of this work was completed by Vivian Li & Sarah Jordaan.

It is highly unlikely that all the 19 proposed LNG projects will come to fruition within the timeframe noted in Figure 3. A report prepared on BC LNG greenhouse gas Life Cycle Analysis for the BC Ministry of Environment, Climate Action Secretariat,[16] states that there are 10 LNG projects proposed for development in BC from 2017 to 2021, with a full potential capacity of approximately 131 MMTPA that would be produced and available for export to overseas market. It was estimated that only 67% of that capacity, or 88 MMTPA, will come on stream by 2021. Another technical report by the Canadian Association of Petroleum Producers (CAPP)[17] forecasts global LNG liquefaction capacity to increase from 294 MMTPA (38.6 bcf/d) in 2011 to 634 MMTPA (83.4 bcf/d) by 2019. The forecast shows that Canada's LNG liquefaction capacity will increase from zero in 2011 to 29 MMTPA (3.8 bcf/d) in 2019.

These lower projections may still be too optimistic. For example, CAPP's projection of 29 MMTPA would be a 26% increment of Canada's current total natural gas production of 110 MMTPA,[18] which may be challenging to accomplish by 2019. The BC Ministry of Environment projects an increase of 88 MMTPA of LNG, implying that Canada would almost double its natural gas production by 2021, adding another 80% increment to current production.[19] For comparison, US natural gas production increased by about 20% during the "shale gas revolution" years of 2008-2013. So far, only two of the proposed projects (Woodfibre and Pacific Northwest), which have a combined liquefaction capacity of 22 MMTPA, have offtake agreements for a part of their liquefaction capacity, with third parties from importing countries. Those offtake agreements total 8.8 MMTPA. In addition, the project LNG Canada Development (with an anticipated liquefaction capacity of 24 MMTPA) has a higher likelihood of being successfully developed. This is because the project is led by Shell, which has 40% stake in the project. Shell will likely allocate its share of LNG production, which amounts to about 9.6 MMTPA of the project's total LNG capacity, through its global portfolio. This makes a total of 18.4 MMTPA of LNG exports likely, and the three projects total LNG capacity would be 46 MMTPA, with 18.4 MMTPA. This paper assumes that the dynamics of global LNG demand and supply would favor the development of about 18.4 MMTPA, increasing Canada's current total natural gas production by 17%.

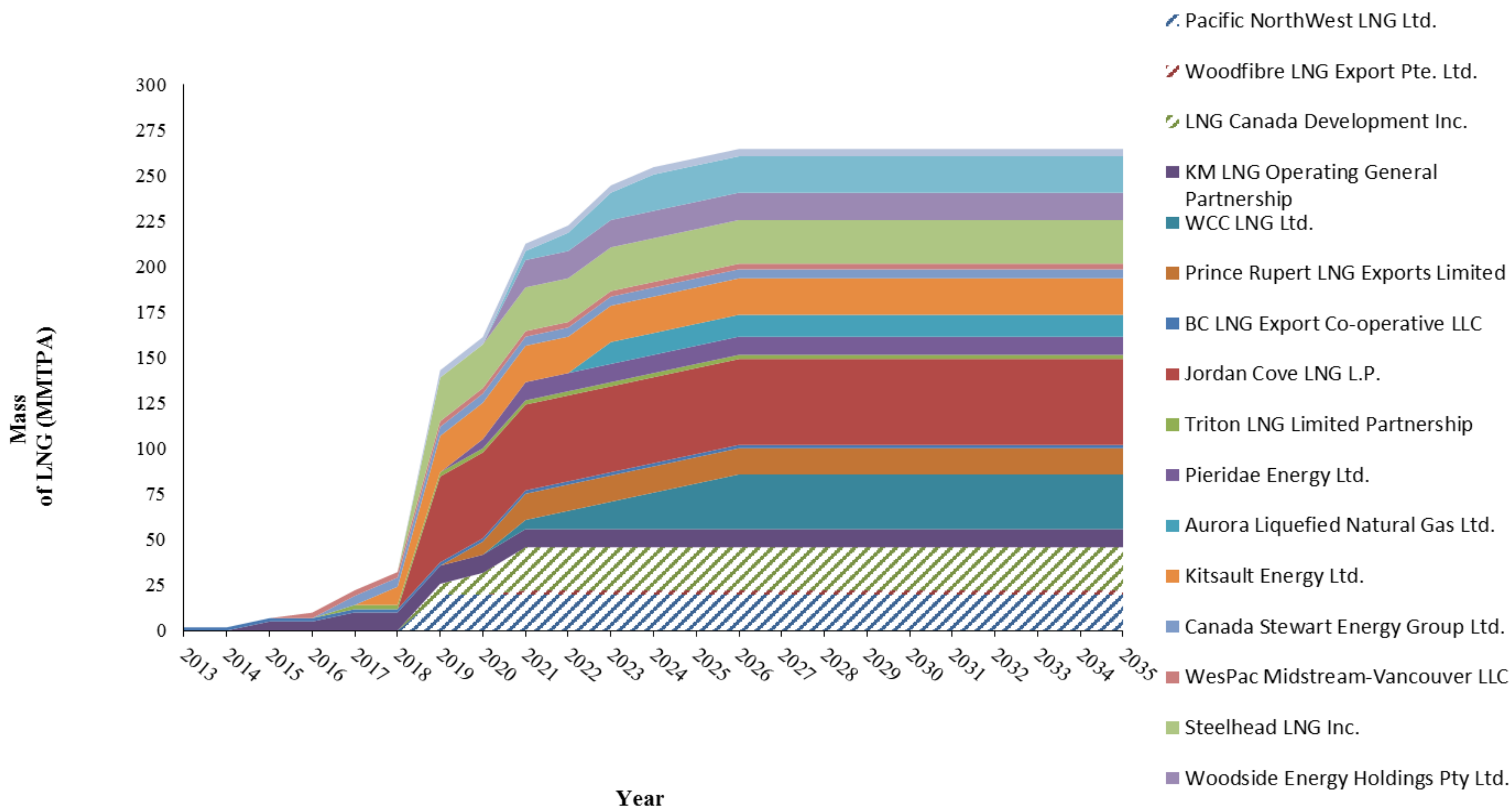
[16] BC Ministry of Environment, Climate Action Secretariat, *British Columbia LNG Greenhouse Gas (GHG) Life Cycle Analysis* (February 2014).

[17] CAPP, *An Overview of the World LNG Market and Canada's Potential for Exports of LNG*, Publication #2014-0010 (Calgary: CAPP, 2014), online: <http://www.capp.ca/publications-and-statistics/publications/238007>.

[18] CAPP, "Statistics", online: <http://www.capp.ca/library/statistics/basic/Pages/default.aspx>.

[19] BC Ministry of Environment, *supra* note 16.

Figure 3: Canada's projected LNG export capacity based on proposed projects with known start dates, submitted for approval to the National Energy Board. Nine of these have been approved and only two of these currently have offtake agreements. The three striped layers at the bottom of Figure 3 represent the two projects with offtake agreements and one with a high likelihood of being developed. Note that the Jordan Cove LNG L.P. Project liquefaction facility is proposed to be built across the border in the US, but supplied with natural gas from Canada.



3.2 Potential Markets for Canada's LNG Exports

Twenty-three potential markets for Canada's LNG exports were reviewed, including issues and trends within countries denoted as traditional buyers, non-traditional buyers and natural gas emerging markets, as well as recent developments and natural gas demand outlook in the LNG industry worldwide.[20] Thirteen of these markets are reviewed below, chosen on the basis of their:

- market size,
- current & planned regasification capacity,
- natural gas demand outlook,
- importance of natural gas in their electricity generation mix, and
- nuclear and coal decommissioning or enforcement of other relevant energy and climate change policies.

Local prices of liquefied natural gas from 2008-2013 were also reviewed.

3.2.1 Traditional Buyers

Traditional buyers are defined by Moore *et al*.[21] as developed economies with strong financial capacities and a long history of buying LNG. These countries may lack resources, requiring further investment while their energy needs grow. "Rules of the game" such as pricing mechanism and delivery gas conditions are well established. The countries examined here are Japan, South Korea, Belgium, the United Kingdom, and Spain.

Japan — Natural gas consumption grew by 25% between 2008 and 2013. Japan's natural gas demand is met primarily by LNG imports. The country is the world's largest LNG importer, accounting for 37% of LNG trade in 2013.[22] The current regasification

[20] MC Moore et al, "Risky Business: The Issue of Timing, Entry and Performance in the Asia-Pacific LNG Market" (July 2014) 7:18 University of Calgary, The School of Public Policy, SPP Research Papers, online: <http://policyschool.ucalgary.ca/sites/default/files/research/moore-lng-onl.pdf>; Anouk Honoré, *The Outlook for Natural Gas Demand in Europe*, OIES Paper No NG 87 (Oxford, UK: Oxford Institute for Energy Studies [OIES], 2014), online: <http://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/06/NG-87.pdf>.

[21] Moore et al, *ibid*.

[22] British Petroleum (BP), *Statistical Review of World Energy* (2014), online: <http://www.bp.com/content/dam/bp/pdf/Energy-economics/statistical-review-2014/BP-statistical-review-of-world-energy-2014-full-report.pdf>.

capacity of 262 BCM (Billion Cubic Meters), mainly owned by electricity and gas utilities, will increase because eight new terminals are expected to come on stream over the period 2014-2016.[23] Natural gas share in the electricity generation mix rose from 28% in 2010 to 48% in 2012,[24] following the Fukushima nuclear disaster in March 2011 and the government's decision to shut down Japan's nuclear reactors. Despite uncertainties regarding fuel consumption in the power sector, and the government plans to restart Japan's nuclear reactors, LNG demand has been forecasted to grow by over 10% from 2015 onwards.[25]

South Korea — South Korea is the second largest LNG importer worldwide and had a natural gas consumption growth of 47% between 2008 and 2013. South Korea's LNG trade was 17% of the global LNG trade in 2013.[26] Regasification capacity (130 BCM), which is owned mainly by Korea Gas Corporation, is expected to increase between 2014 and 2015, as two new terminals are envisioned.[27] Electricity from natural gas is 21% in the electricity generation mix.[28] Changes in Korea's energy policy mean an expanding use of LNG for power generation and less reliance on nuclear power. Natural gas demand is expected to grow by almost 2% per year through 2035, meaning an open gap from 2025 onwards (from 20 MMTPA to 41 MMTPA).[29]

Belgium — Due to the economic difficulties in Europe, natural gas consumption decreased by 12% in 2011 compared to the previous year, and has remained stagnant since then, at 17 BCM. Belgium is dependent on energy imports, including all of its natural gas requirements. LNG imports accounted for over 3 BCM in 2013,[30] while regasification capacity is 9 BCM.[31] The role of natural gas in the electricity generation mix is expected to grow from its current 34% share as the country plans to be less dependent on nuclear energy.[32]

United Kingdom (UK) — Natural gas consumption dropped by 22% in 2013, compared with 2010, when consumption peaked at 94 BCM. Despite being the second

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[23] International Group of Liquefied Natural Gas Importers (GIIGNL), *The LNG Industry in 2013* (2014), online: <http://www.giignl.org/publications/lng-industry-2013>.

[24] International Energy Agency (IEA), *Electricity Information Edition 2012* (Paris: OECD/IEA, 2012), Part IV "Detailed OCDE [Organisation for Economic Co-operation and Development] Electricity and Heat Data"; US Energy Information Administration (EIA), *Japan Country Analysis Brief* (Washington, DC: EIA, 2014), online: <http://www.eia.gov/countries/cab.cfm?fips=JA> (Accessed in 2014); Japan Electric Power Information Center (JEPIC), *Operating and Financial Data* (2014), online: <http://www.jepic.or.jp/en/data/EPIJ2014JapanData.pdf>.

[25] Moore et al, *supra* note 20.

[26] BP, *supra* note 22.

[27] GIIGNL, *supra* note 23.

[28] IEA, *supra* note 24.

[29] Moore et al, *supra* note 20.

[30] BP, *supra* note 22.

[31] GIIGNL, *supra* note 23.

[32] Honoré, *supra* note 20.

largest LNG importer within the European region, LNG imports in UK fell to just above 9 BCM in 2013, as a result of lower gas demand.[33] The electricity generation mix is currently dominated by natural gas (46%).[34] The natural gas share is expected to increase due to the plan to decommission about one third of the UK's nuclear plants by 2020. Natural gas is expected to fill the gap along with renewables.[35]

Spain — Natural gas consumption has consistently decreased since 2008. In 2013, the country imported 15 BCM of LNG, down by 30% compared to the previous year. However, Spain is still the largest LNG importer within the European region, with a regasification capacity of 60 BCM.[36] Increasing use of renewable energy sources for power generation has impacted natural gas demand, which has been increasingly driven by the availability of hydro and wind generation. Natural gas demand for the power sector would increase if there is a slowdown in renewable additions, change in environmental policies, decommissioning of nuclear plants, or reduction in coal-fired electricity generation in future years.[37]

3.2.2 Non-traditional Buyers

Non-traditional buyers are defined by Moore *et al*.[38] as less-developed economies, with greater commercial risk profile. Since their entrance into the market was made in the early- and mid-2000s, they have a short history of buying LNG. These countries produce natural gas domestically, but are not capable of meeting their energy needs. Argentina and Brazil are developing countries, but they fulfill the same profile described by Moore in regards to non-traditional buyers of the Asian-Pacific market. The countries, examined here, are China, India, Argentina, and Brazil.

China — Natural gas consumption almost doubled between 2008 and 2013, and LNG imports grew over 450% in the same time period.[39] Regasification capacity is 44 BCM, including four terminals commissioned in 2013. Four other terminals are under construction.[40] Coal largely dominates the electricity generation mix (77%), while gas accounts for less than 2%.[41] Some particular features of this market are: sustained economic growth and growing population increasing demand for energy; a large resource base currently under development, including unconventional gas (shale gas and coalbed

[33] BP, *supra* note 22.
[34] IEA, *supra* note 24.
[35] Honoré, *supra* note 20.
[36] BP, *supra* note 22; GIIGNL, *supra* note 23.
[37] Honoré, *supra* note 20.
[38] *Ibid*.
[39] BP, *supra* note 22.
[40] GIIGNL, *supra* note 23.
[41] EIA, *International Energy Outlook 2013* (Washington, DC: EIA, 2013), online: <http://www.eia.gov/forecasts/ieo/pdf/0484%282013%29.pdf>.

methane); and infrastructure available in the mid-stream value chain (pipeline networks). The power sector has been the main driver for LNG demand in recent years. Existing LNG contracts will meet China's gas needs until 2020, when there will be a supply/demand gap of 15 BCM. If proposed pipelines are not built, an increasing LNG demand would be expected beyond 2020.[42]

India — Natural gas consumption rose by 25% between 2008 and 2013. During this period, LNG imports grew by 65%.[43] Regasification capacity, including two terminals commissioned in 2013, is 28 BCM; four other terminals are under construction. The potential expansion of the Hazira terminal would increase regasification capacity by 7 MMTPA by 2017-2018.[44] Coal largely dominates the electricity generation mix (68%), while gas only accounts for 12%.[45] Increasing concerns about the reliability of its domestic supplies, plus existing fields' depletion open a supply/demand gap that is expected to reach about 56 BCM by 2030. The country has secured LNG contracts with the US.[46]

Argentina — Natural gas plays a crucial role in Argentina's energy and electricity generation mixes, with a share of 51% and 62%, respectively.[47] LNG increasingly meets natural gas needs; in 2013, LNG share was about 57% of total Argentinean natural gas imports. The country imported near 7 BCM of LNG — up by 33% compared with the previous year.[48] Argentina also increasingly relies on the spot market, being one of the best markets for LNG sellers due to high prices.[49] In 2013, the country accounted for 24 reloaded cargoes, which represents 29% of worldwide reloaded LNG cargoes.[50] The country adopted regulatory reforms to enable domestic gas production, particularly unconventional production. However, several issues need to be address before unconventional gas becomes commercially viable in the country.[51]

[42] Moore et al, *supra* note 20.

[43] BP, *supra* note 22.

[44] GIIGNL, *supra* note 23.

[45] EIA, *supra* note 41.

[46] Moore et al, *supra* note 20.

[47] BP, *supra* note 22; Department of Mining & Energy of Argentina, *Informe Estadístico del Sector Eléctrico 2012* / *Statistical Report on Electricity Sector 2012*, Table 2.1 "Generación de Energía Eléctrica por tipo y jurisdicción / Electricity Generation by Source and Jurisdiction", online: <http://www.energia.gov.ar/contenidos/verpagina.php?idpagina=3783>.

[48] BP, *ibid*.

[49] M Parraga & B Ellsworth, "As Venezuelan deliveries wane, allies tap traders for pricey fuel", *Reuters* (21 August 2014), online: <http://uk.reuters.com/article/2014/08/21/venezuela-oil-exports-idUKL2N0QR1I620140821>.

[50] GIIGNL, *supra* note 23.

[51] EIA, *Argentina Country Analysis Brief* (Washington, DC: EIA, 2014), online: <http://www.eia.gov/countries/country-data.cfm?fips=AR&trk=m>; David Mares, *Political Economy of Shale Gas in Argentina* (Houston, TX: Center for Energy Studies, Rice University's Baker Institute and Harvard Kennedy School,

Brazil — Brazil became a natural gas importer in 2008 due to decreasing production and growing demand. In 2013, the country imported just over 5 BCM, up by 59% compared with the previous year.[52] Brazil's electricity generation mix is largely dominated by hydroelectricity (79%).[53] Severe dry seasons have been one of the main drivers for increasing LNG demand between 2013 and 2014, due to lower hydropower generation. Like Argentina, Brazil increasingly relies on the spot market for LNG. In 2013, the country accounted for 18 reloaded cargoes, which represents 22% of worldwide reloaded LNG cargoes.[54] Brazil is expected to increase domestic gas production from its pre-salt fields. However, local content policies have prevented Brazil from executing its oil and gas projects as planned.[55]

3.2.3 Other Potential Markets

The remaining 15 countries are still considered potential targets for Canada's LNG export beyond 2030 because their natural gas supply/demand gap is expected to increase. These markets either lack a resource base, have contracts that are about to expire, or have uncertainties in some of their sources of supply. For example, they may be supplied by countries such as Indonesia and Malaysia that are likely to become LNG importers in the long-term. Countries in this category include Taiwan, France, Turkey, and Germany.

Taiwan — Natural Gas consumption has grown 41% between 2008 and 2013, driven by the power sector. Taiwan, considered a traditional buyer in the Asia-Pacific region, accounted for 5% of world's LNG imports in 2013.[56] The country's electricity generation mix is dominated by coal (50%), followed by gas (25%).[57] LNG demand is likely to grow steadily — there are no major energy policy changes expected[58] and new regasification projects are not envisioned. Growing natural gas demand, expiring contracts and unreliability of current suppliers (Indonesia, Malaysia) may open a supply/demand balance gap of about 6-8 MMTPA by 2020 and beyond.[59]

Belfer Center for Science and International Affairs, 2013), online: <http://belfercenter.ksg.harvard.edu/files/CES-pub-GeoGasArgentina-110113.pdf>.

[52] BP, *supra* note 22.

[53] EIA, *supra* note 41.

[54] GIIGNL, *supra* note 23.

[55] EIA, *Brazil Country Analysis Brief* (Washington, DC: EIA, 2013), online: <http://www.eia.gov/countries/cab.cfm?fips=BR>.

[56] BP, *supra* note 22.

[57] Ministry of Economic Affairs of Taiwan (MOEA), Bureau of Energy, *Energy Statistical Handbook 2012*, 2d ed (Taiwan, ROC: MOEA (2013), online: <http://web3.moeaboe.gov.tw/ECW/english/content/SubMenu.aspx?menu_id=1537>.

[58] Moore et al, *supra* note 20.

[59] *Ibid*.

France — France is considered a traditional buyer within the European region. Its natural gas requirements are met 100% by imports. It is the third largest LNG importer within the region, trading 8.7 BCM in 2013.[60] Its current regasification capacity is about 24 BCM, and there are no new projects envisioned at this time.[61] France is the second largest electricity market in Europe and power generation is largely dominated by nuclear (76%) — natural gas share is only 4%.[62] France recently banned hydraulic fracturing, and is working to add intermittent renewables to its grid that may require natural gas power to complement them potentially creating an opportunity for further LNG imports. Natural gas could take market share from the small coal sector by 2020.[63]

Turkey — Like France, Turkey is considered a traditional buyer of LNG, with regasification capacity of 12 BCM. In 2013, Turkey imported 6.1 BCM of LNG.[64] Both total energy mix and the electricity generation mix are dominated by natural gas, with shares of 36% and 46%, respectively.[65] In spite of this, nuclear, renewables and coal are expected to increase their role in the electricity generation mix. Only the residential and commercial sectors will likely be the key drivers for increasing natural gas demand. The natural gas demand from the power sector would increase if plans for nuclear power are reversed.[66]

Germany — Germany is considered an LNG emerging market. 86% of its natural gas use comes from imports, which is mainly through pipelines. About 41% (40 BCM) of gas imports by pipeline comes from Russia.[67] Despite fast growth in renewables and attractive coal prices, natural gas could increase its role in the electricity generation mix beyond 2020 due to decommissioning of nuclear plants and slow decline in coal generation. Power and transport sectors appear to be key drivers in natural gas demand recovery in the 2020s. Natural gas supply from Russia through Nord Stream pipeline is likely, but unreliability and political risks associated with Russian supplies could turn Germany towards other potential suppliers.[68]

Other Asian Emerging Markets — Southeast Asian countries such as Thailand, Singapore, Malaysia, Indonesia, Philippines, and Vietnam will likely become greater LNG importers in the coming decades. They have started to import LNG recently (from

[60] BP, *supra* note 22.
[61] GIIGNL, *supra* note 23.
[62] EIA, *supra* note 41.
[63] Honoré, *supra* note 20.
[64] GIIGNL, *supra* note 23.
[65] EIA, *supra* note 41; BP, *supra* note 22.
[66] Honoré, *supra* note 20.
[67] BP, *supra* note 22.
[68] Honoré, *supra* note 20.

2011) and the supply/demand gap may open further around 2020 due to unreliability of supply by pipelines.[69]

Other European Emerging Markets — Albania, Croatia, Cyprus, and Ireland are expected to be LNG importers in the long-term as they have enforced climate change policies aimed at reducing carbon dioxide (CO_2) emissions from coal and oil power plants, and also plan to decommission nuclear plants. More than six regasification projects are envisioned and would add no less than 28 MMTPA to the world regasification capacity if all of the proposed terminals were built.[70]

3.3 Natural Gas Prices

Another way of assessing likely destinations for Canadian LNG export is through reviewing where LNG import prices are highest. A review of the historical landing prices of natural gas in 11 key importing countries for the period 2008-2013 was completed by extracting monthly price data from the Federal Energy Regulatory Commission (FERC).[71] The Henry Hub and AECO-C spot prices were also included as the respective national benchmark prices for US and Canada. Results confirmed that while there is no global market for the price of natural gas, regional trends are emerging. Natural gas prices diverged starting in the middle of 2010, and by the last quarter of 2013, three broad market prices of gas existed. They can be classified by region: North America, Europe and Asia-Pacific/spot market.

The North American region, focusing on US and Canada, had the lowest market prices, driven by shale gas production as well as competitive markets and gas-to-gas pricing. In contrast, in the European and Asia-Pacific regions natural gas prices are linked to oil. The European region, made up of Belgium, UK and Spain, has higher prices and showed a price average around $10/MMBtu (USD). The highest market prices are in the Asia-Pacific region consisting of Japan, South Korea, India and China, with an average price of about $15/MMBtu at the end of 2013. Mexico, Argentina and Brazil also fall into the region with an average price similar to importing countries in the Asia Pacific region, because these three countries have relied increasingly on the spot market.

LNG reference price for Altamira terminal, on the East coast of Mexico increased more than 280% from $4.42/MMBtu (USD) in May 2013 to $17.20/MMBtu in June 2013. According to media reports, Mexico had to turn to the costly spot cargoes due to rising demand, falling domestic output and pipeline bottlenecks for less expensive US

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[69] Moore et al, *supra* note 20.

[70] Honoré, *supra* note 20.

[71] FERC, "Natural Gas Markets: National Overview", online: <http://www.ferc.gov/market-oversight/mkt-gas/overview.asp>.

imports by pipeline.[72] Figure 5 shows the historical natural gas prices for the period October 2008 to October 2013.[73]

There are several points to note regarding this data collection effort. First, data for Argentina, Brazil and China are not available for periods before August 2012, even though these countries imported LNG before this date. While Argentina and Brazil started to import LNG in 2008, China started in 2006 and became a net importer in 2007. Second, data corresponding to Mexico, Japan, Korea, India, Spain, Belgium, UK, and US. Lake Charles and Cove Point are not available for three months: February 2011, July 2012 and December 2013. The price of natural gas for the preceding month was carried forward for the missing month as an approximation.

Broadly speaking three regional prices are emerging across the globe that are relevant to the future of LNG export from Canada and globally: North America, Europe, and Asia-Pacific/spot market. There are qualifications to this general division, which are noted above,[74] but the broad categories remain useful.

4. Life Cycle Assessment of LNG Export for Electricity Generation: Downstream Emissions

The objective of this section is to determine first-order estimates for the greenhouse gas implications of LNG export for electricity generation in the thirteen most likely potential markets: China, India, Japan, South Korea, Spain, the UK, Belgium, Argentina, Brazil, Taiwan, France, Turkey, and Germany.[75] To meet this objective, the existing electricity mix in each potential market was determined. First order estimates for the life cycle greenhouse gas emissions for each generation type were assessed for each country. These estimates were used to determine what types of electricity generation imported LNG from Canada might displace. The total amount of LNG available from Canada was determined by the offtake agreements identified in Section 3.

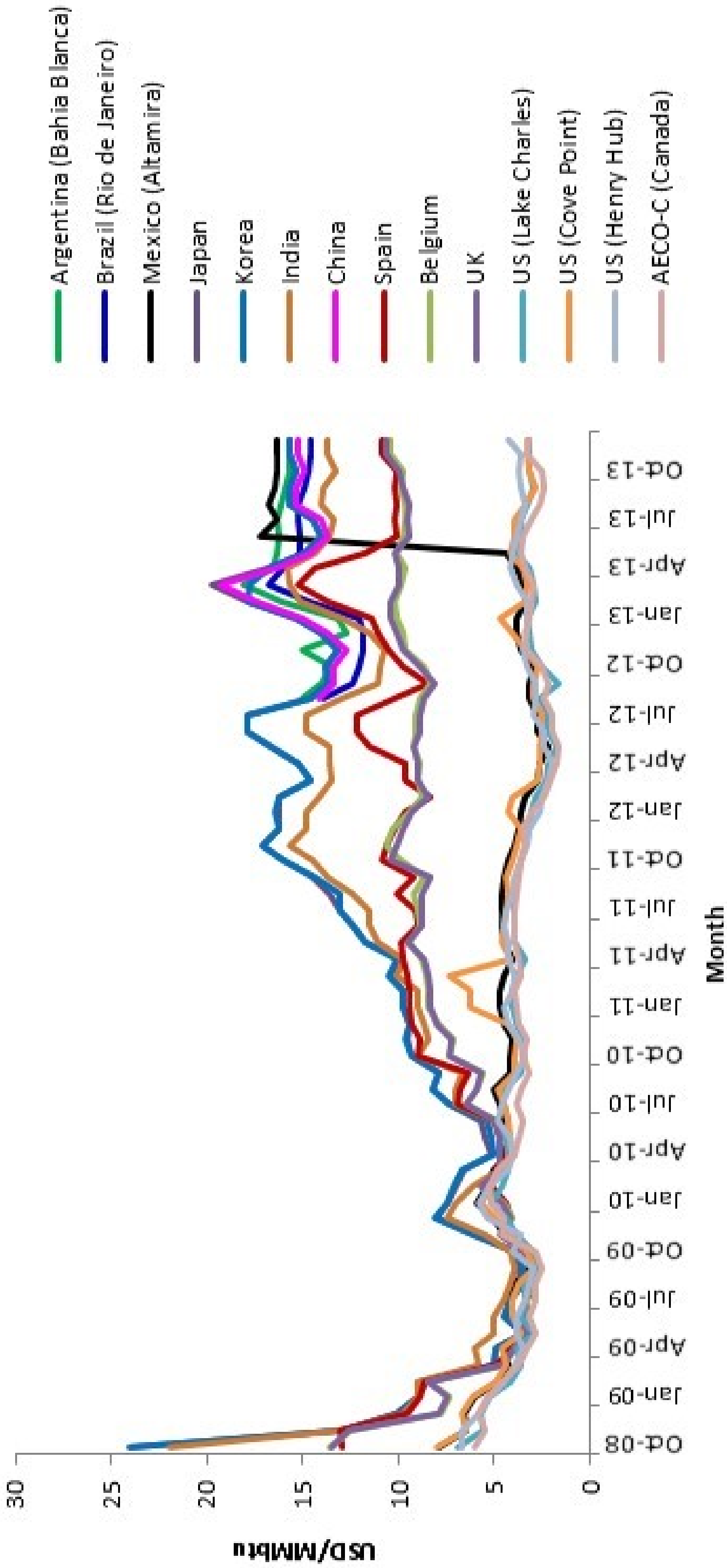
[72] O Vukmanovic & D Garcia, "Mexico shift to LNG drives gas costs higher", *Reuters* (9 May 2013), online: <http://www.reuters.com/article/2013/05/09/energy-lng-mexico-idUSL6N0DP24F20130509>.

[73] FERC, "World Estimated Landed Prices 2008-2013", online: <http://www.ferc.gov/market-oversight/othr-mkts/lng/archives.asp>; EIA, "Natural Gas Data 2008-2013, Henry Hub Natural gas Spot Prices" (2014), online: <http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm>; CAPP, "Reference Natural Gas Prices" (2006-2009); CAPP, "Reference Natural Gas Prices" (2010-2013).

[74] For example, Mexico moved rapidly from a North American price to a Latin American price in mid-2013.

[75] In this paper, it is assumed that the LNG is used for electricity. The electricity generation mixes of the most likely potential markets were also reviewed.

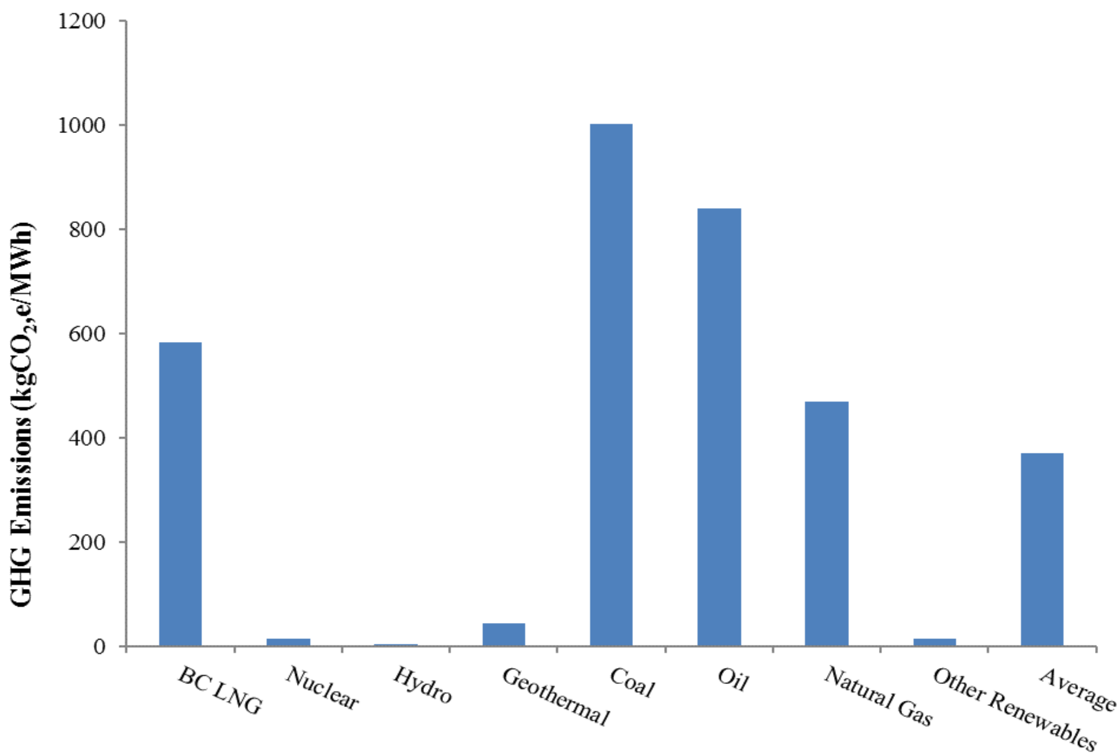
Figure 4: Historical natural gas prices for different markets, 2008-2013 (FERC). These have not been converted to current day, but rather reflect priced reported during the month noted.



4.1 Life Cycle Emissions from Different Power Generation Technologies

Figure 5 shows the magnitude of the life cycle greenhouse gas emissions of electricity generation from different sources, compared to the estimated life cycle emissions that would be generated using BC LNG for electricity generation in markets abroad. The emissions values for the BC LNG as an electricity generation source are the same as those shown in Figure 2. The values of emissions from electricity generated from other sources are from a special report on renewable energy sources and climate change mitigation,[76] and they correspond to the 50th percentile for each technology, from a meta-study of more than 50 papers. The value shown in the figure for "Other Renewables" is an average of life cycle greenhouse gas emissions from electricity generated from ocean, wind, biomass, solar CSP and solar PV. The average value shown is the mean of all estimated greenhouse gas emissions from all other sources of electricity on the chart.

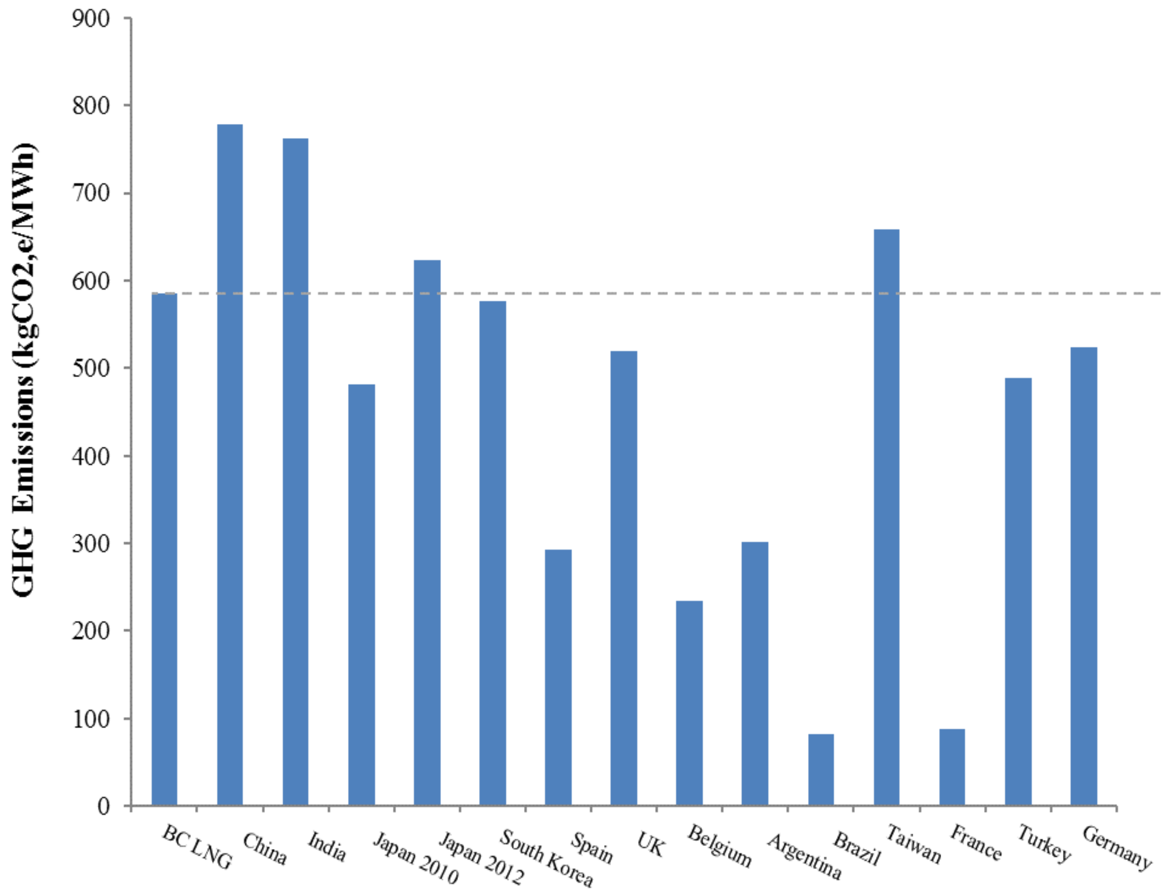
Figure 5: Life cycle greenhouse gas emissions from different sources of electricity generation



[76] Renewable Energy Sources and Climate Change Mitigation: Special Report of the Intergovernmental Panel on Climate Change (Geneva: IPCC, 2012), online: <http://srren.ipcc-wg3.de/report/IPCC_SRREN_Full_Report.pdf>.

Figure 6 shows that electricity generation using BC LNG would reduce greenhouse gas emissions only in countries heavily dependent on coal or oil as the major source of the electricity generation.

Figure 6: Life cycle greenhouse gas emissions from electricity generation in potential market countries

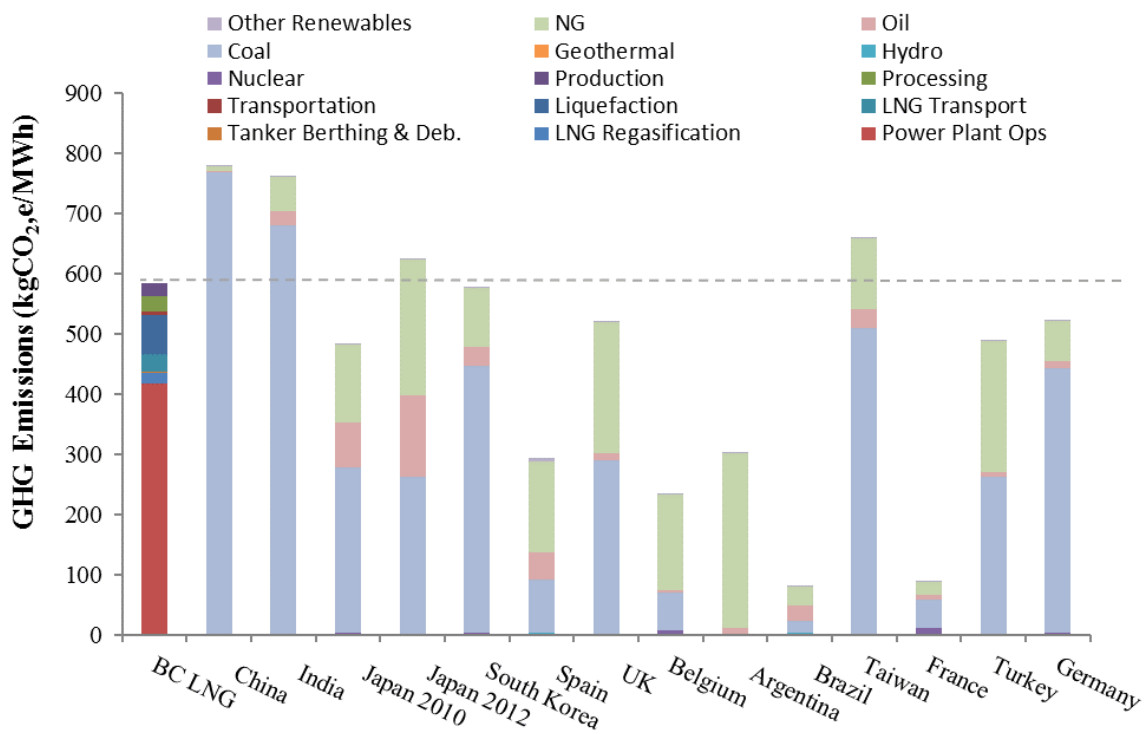


While Figure 6 and the remainder of this report focuses on the case where the average electricity generation is displaced, Figure 5 is particularly useful for showing what the displacement of a marginal unit of electricity might look like. It shows how net emissions would change if natural gas displaces other sources of electricity.

4.2 Life Cycle Greenhouse Gas Emissions of Electricity Generation in Potential Export Markets

Given the generation mix of the countries that are likely to import LNG from Canada and the life cycle emissions of each power type, weighted averages of life cycle greenhouse gas emissions of electricity generation in each of those countries were estimated. Figure 6 compares the estimated life cycle greenhouse gas emissions from electricity generation in those countries to the life cycle emissions associated with power from Canadian LNG, while Figure 7 presents the same information, breaking down a country's average life cycle emissions from electricity generation by power type. If the data available accurately estimates greenhouse gas emissions from Canadian LNG, then China, India, Japan, and Taiwan would lower the life cycle greenhouse gas emissions associated with their power sectors by importing Canadian LNG to displace a representative portion of their power sector.

Figure 7: Life cycle greenhouse gas emissions of electricity generation in potential market countries, subdivided by greenhouse gas contribution of different sources of electricity shown in light shaded colors. Compared to Canadian LNG exports, divided by stage of life cycle, shown in dark shaded colors.



From this assessment, we can draw several conclusions and identify key limitations in the data. First, there are clear first-order differences in greenhouse gas emissions by country. While improving data is necessary for more accurate results, we can determine in which countries LNG exports are most likely to reduce power sector greenhouse gas emissions. Second, a country-level database of LCAs would make estimates of potential displacement more accurate by considering factors such as the influence of the vintage of the generation fleet and country-specific technologies in use that might affect the average emissions intensity of each country's existing power sources. While additional data and research are clearly required, these first-order estimates can provide direction for where research efforts should be placed.

4.3 Greenhouse Gas Implications of Displacing Electricity with Natural Gas Fired Electricity Using Canadian LNG

As noted, one realistic estimate of Canada's LNG export capacity is 18.4 MMTPA. In Table 3, the quantity of electricity that can be generated from 18.4 MMTPA of Canadian LNG is given as a percentage of the electricity generated in potential export countries in 2010.

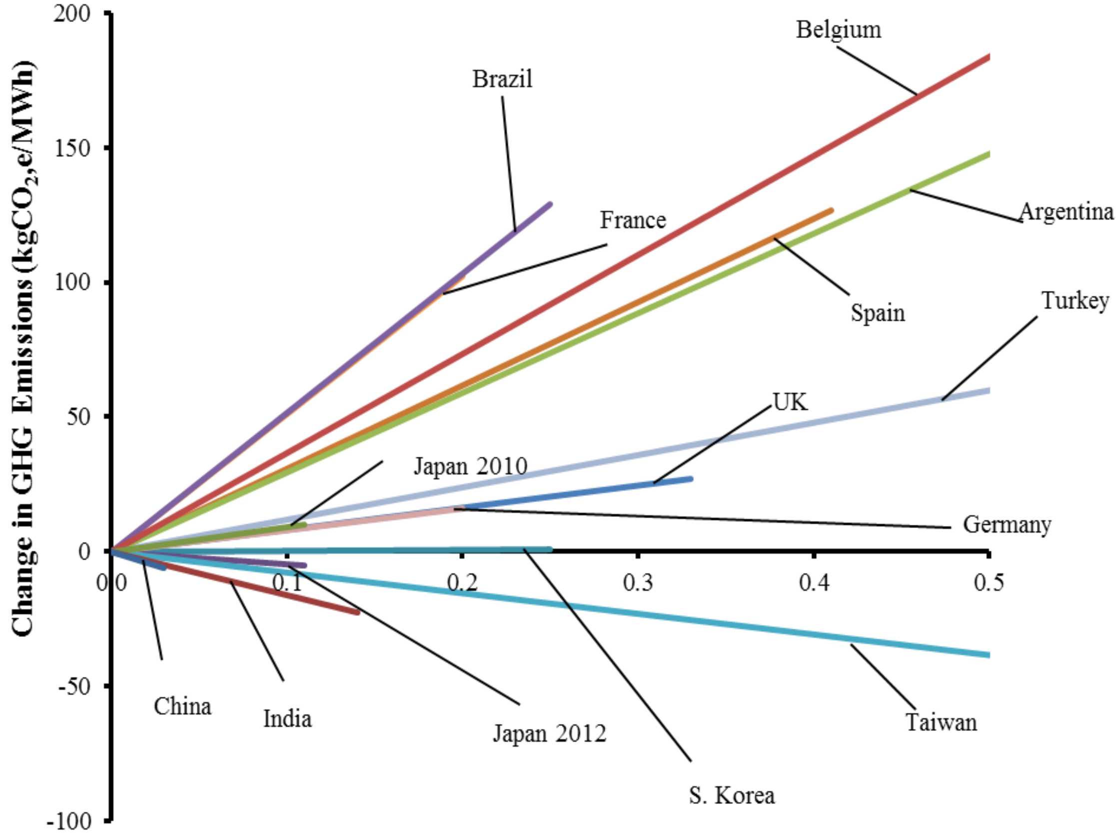
Table 3: Percentage of each export country's total electricity that could theoretically be displaced by Canada's projected 18.4 MMTPA of LNG exports. The second column shows potential greenhouse gas emissions increase/decrease per unit of electricity production, based on each country's electricity generation mix.

Potential Export Country	% of Country's Electricity Generation (2010)	Greenhouse gas emissions increase/decrease (kgCO2 e/MWh)
China	3	-6
India	14	-23
Japan 2010	11	10
Japan 2012	11	-5
South Korea	25	1
Spain	41	127
United Kingdom	33	27
Belgium	132	368
Argentina	112	295
Brazil	24	129
Taiwan	51	-39
France	22	102
Turkey	59	70
Germany	20	16

Based on Canada's estimated LNG export capacity, the effect on greenhouse gas emissions in the import countries as a result of the displacement of the current electricity generation mix is shown in Figure 8. Each line ends either where Canada's 18.4 MMTPA of LNG is exhausted or at 50% if Canada's LNG could, in theory, displace over half of the country's power sector.

While these are first-order estimates, they make plain that the net climate impact of LNG depends crucially on which countries are importing it. To better quantify the magnitude and uncertainty associated with this impact, more detailed country-level analysis is required. Figure 5 shows how this may compare if a specific type of source is displaced on the margin (rather than displacing a mix of sources that is representative of the current mix).

Figure 8: Net greenhouse gas emissions displacement from Canadian LNG (BC LNG) export to different markets. The amount of displacement is limited by the amount of Canadian LNG exports expected.



X axis represents share of existing electricity displaced by LNG use in electricity generation.

5. British Columbia and Canada's Authority to Regulate Life Cycle Greenhouse Gas Emissions from LNG

The net climate impact of LNG exports from Canada thus depends on both 1) upstream greenhouse gas emissions from production through liquefaction within Canada and 2) what sources of energy it displaces in LNG import markets abroad. Does it displace coal power in China or renewable power in Spain? Can a regulator in BC or even Canada address such questions? If not, what actors should be involved in cooperating to address the greenhouse gas impact of LNG exports?

Upstream emissions sit squarely within the regulatory authority of provincial and federal jurisdictions. BC regulates natural gas production under its Oil and Gas Activities Act and has proposed the Greenhouse Gas Industrial Reporting and Control Act to address liquefaction facilities. As this work progresses, regulators should take pains to ensure standardization of reporting to enable careful comparisons across LCAs of natural gas and, to the greatest extent possible ensure adoption of cost-effective controls like those prescribed by the Natural Gas STAR (NG STAR), National Emission Standards for Hazardous Air Pollutants (NESHAP), and New Source Performance Standards (NSPS) programs in the US. As previously mentioned, it is also known that large uncertainties exist in the data, necessitating more accurate measurement as natural gas production increases.

Downstream emissions, however, present tricky jurisdictional issues: what if, anything, can BC do to push its LNG exports to countries where LNG will displace carbon-intense electricity production? The short answer is that several jurisdictions are experimenting with modes of regulation designed to reduce life cycle emissions in other jurisdictions, but the legal validity of these regulations remains an open question.

The courts and legal analysts that set jurisdictional boundaries for national and provincial regulators have not kept up with the pace of scientific and regulatory innovation in life cycle standards. As a result, government life cycle standards, such as those for electricity and motor fuels, are currently being challenged by litigants who argue that they are illegal under principles (often embodied in constitutional law) that prohibit subnational units from erecting intra-national barriers to trade.[77] For example, one lawsuit challenged California's Low Carbon Fuel Standard[78] and a current suit questions whether regulators in Minnesota may treat electricity from North Dakota differently based on how it was produced in that state.[79] Inconsistencies in LCAs and poor measurements from actual facilities further confound the problem. Should the focus be LCA standards or standardizing LCAs of natural gas to ensure accurate conclusions are drawn? Finally, regulated parties have increasingly begun to question whether these laws also violate international trade principles embodied in treaties such as the General Agreement on Tariffs and Trade and the North American Free Trade Agreement, which could lead to further litigation.[80]

Assuming, however, that such standards were upheld, could BC adopt a similar standard? That is, if California can favor imports from countries that produce oil by low carbon methods, can BC favor export to countries where Canadian LNG is likely to decrease emissions? These questions engage with an existing literature on regulation across international borders and the appropriate boundaries of national and subnational

[77] AB Klass & E Henley, "Energy Policy, Extraterritoriality, and the Dormant Commerce Clause" (June 2014) 5 San Diego Journal of Climate and Energy Law 127.

[78] DK Lee & TP Duane, "Putting the Dormant Commerce Clause Back to Sleep: Adapting the Doctrine to Support State Renewable Portfolio Standards" (2013) 43 Envtl L 295.

[79] Patrick Zomer, "Note: The Carbon Border War: Minnesota, North Dakota, and the Dormant Commerce Clause" (2010) 8:1 University of St. Thomas Law Journal 60.

[80] JW Coleman, "Importing Energy, Exporting Regulation" (2014) 83:3 Fordham L Rev 1357.

regulation.[81] But climate change has put an increased focus on these questions, spawning a diverse literature on the appropriate limits of national and subnational climate regulation.[82] Simply put, the question is (a) how much may a regulator address the history of a product consumed within its borders, that is, the upstream consequences of the product's consumption, and (b) how much may a regulator address the future of a product produced within its borders, that is, the downstream consequences of its production. One set of theories suggests that regulators may not address either set of consequences, and are limited to addressing only consequences manifest within their geographic jurisdiction.[83] Another set of theories suggests that regulators should take responsibility for upstream emissions, but not downstream emissions.[84] An emerging, but not yet fully articulated theory, suggests that regulators can and should take responsibility for downstream emissions as well; this theory is manifest in efforts to limit fossil fuel exports on the basis of the emissions that will result from eventually burning those fuels elsewhere.[85] Ultimately, even if it is possible to regulate downstream emissions, it may be unwise for countries to try to police greenhouse gas emissions in their downstream trading partners. Instead, countries may want to engage in bilateral or multilateral efforts to encourage energy-trading relationships that can ensure that LNG addresses both economic and environmental goals.[86] Finally, decision-makers must face data uncertainty when establishing policies and regulations. Should BC, Canada or other regions apply such standards with existing uncertainties in the data? At what point does the data become strong enough to apply such regulations?

6. Conclusion

In this report, a LCA was performed to determine the life cycle implications of LNG export from Canada. While the focus here was Canadian potential, such analysis can

[81] J Turley, "Transnational Discrimination and the Economics of Extraterritorial Regulation" (1990) 70 BUL Rev 339; JI Garvey, "A New Evolution for Fast-Tracking Trade Agreements: Managing Environmental and Labor Standards Through Extraterritorial Regulation" (2000-2001) 5 UCLA J Intl L & Foreign Aff 1-58.

[82] Kirsten H Engel, "The Dormant Commerce Clause Threat to State Market-Based Environmental Regulation: The Case of Electricity Deregulation" (1999) 26:2 Ecology LQ 243; A Lucas & J Yearsley, "The Constitutionality of Federal Climate Change Legislation" (2012) 23 Journal of Environmental Law and Policy 205-236; Mark Wu & James Salzman, "The Next Generation of Trade and Environment Disputes: The Rise of Green Industrial Policy" (2014) 108:2 Nw UL Rev 401.

[83] Douglas A Kysar & Bernadette A Meyler, "Like a Nation State" (2008) 55 UCLA L Rev 1621.

[84] Glen P Peters, "From production-based to consumption-based national emission inventories" (2008) 65:1 Ecological Economics 13-23.

[85] E Sheargold & S Walavalkar, *NEPA and Downstream Greenhouse Gas Emissions of US Coal Exports*, White Paper (New York: Columbia Center for Climate Change Law (CCCL), 2013).

[86] The White House, Office of the Press Secretary, News Release, "US-China Joint Announcement on Climate Change" (12 November 2014), online: <http://www.whitehouse.gov/the-press-office/2014/11/11/us-china-joint-announcement-climate-change>.

inform other countries interested in LNG export, import, or cooperation. Key conclusions are summarized in this section, first those from each objective, then overall conclusions and recommendations for future research.

The State of Greenhouse Gas Emissions Data for the Canadian Natural Gas Supply Chain

From examining the upstream natural gas supply chain, it was found that the data are still limited and are in need of improved estimates. GHGenius data were the most complete from a life cycle perspective but were limited because they applied data from a variety of geographic regions. Provincial data are specific to the region; however, they are subject to varying reporting standards and limited data quality (e.g. limited sample sizes in measurements or aggregated reporting). Additionally, the data for Canadian-specific liquefaction plants are limited, indicating a need to stay abreast of data as they become public. Finally, the LCAs reviewed were found to have inconsistent systems boundaries and methods, indicating a need to develop standardized methods to ensure studies can be rigorously compared. From such standardization, more meaningful conclusions can be drawn about variability of emissions across regions and, more importantly, how emissions can be reduced through operator practice and control technologies. This is a matter of not only greenhouse gas reduction but also of capturing a valuable commodity — methane that would otherwise leak to the atmosphere, so cost effective control technologies are an attractive option for the industry. This is particularly relevant for AB and Canadian federal reporting thresholds, which were found to be high, resulting in unreported release of a valuable commodity that would otherwise be captured and sold on the market. Future assessments should focus on improving play-level estimates using a standardized approach to LCA as well as improving device-level estimates for these regions to promote economic and environmental efficiency. A strong focus should be placed on measurement, such that estimates can be verified with facility-level data. New liquefaction estimates should rely on plant designs and mass energy balances that are specific to BC. These actions will provide a strong basis to confirm that the Government of BC can meet the goal of the cleanest LNG from a life cycle perspective while improving overall profits.

LNG Export Market Potential, Landed Natural Gas Prices and Current Offtake Agreements

Through our review, we identified potential export markets, landed natural gas prices for each market, and current offtake agreements. While there are currently nineteen projects proposed in western Canada, only two have offtake agreements. Current prices suggest favourable economics according to existing cost estimates;[87] however, more detailed economic analysis is required to assess price variability and the effects of competition in the market. Given the globally competitive nature of the existing markets, it is important to track changes to ensure that opportunities for Canadian producers are known. While this paper focused on electricity generation, it should be noted that there are clearly alternative end uses within each market (e.g. home heating). Future research should investigate not only displacement of electricity, but also what other end uses may be met, which will give a more complete picture of which sources of energy LNG imports might displace.

First-Order Estimates for the Greenhouse Gas Implications of LNG Export for Electricity Generation in Potential Markets

Through completing the first two objectives, data were compiled to undertake first-order estimates for potential emissions displacement in key export markets. Our estimates rely on simple descriptive statistics from broad LCA reviews. This indicates a need for more comprehensive, country-specific datasets to be included in future analyses. For example, the vintage of the fleet and technologies applied in power generation can affect country-level emissions, leading to subtleties not captured in our first-order estimates. Not only the markets, but the available end uses should be a factor in considering total impacts. For example, it has been found that emissions leakage rates must be below 1% for compressed natural gas vehicles to show life cycle climate benefits over the current fleet.[88] Future research should include an investigation of both market potential for alternative end uses but also potential impacts.

Regulatory Implications for the Canadian Federal and Provincial Governments Considering the Implications of the Analysis and Uncertainty in the Data

BC should consider ensuring that its greenhouse gas reporting regulations harmonize with those of other jurisdictions to enable careful comparisons of LCAs across jurisdictions. It should also prescribe cost-effective controls that will prevent undue greenhouse gas emissions while at the same time conserving the maximum value of resource. BC will also have to consider whether and how it wants to implement its promise of lowest life cycle greenhouse gas emissions. It could follow the example of other countries that have begun to adopt mandatory life cycle emission standards, but that presents several potential problems: potentially overstepping its jurisdictional bounds,

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[87] Edward L Morse et al, *Energy 2020: North America, the New Middle East?*, Citi GPS: Global Perspectives & Solutions Report (Lemont, IL: US DOE, Argonne National Laboratory, 2012).

[88] Ramon A Alvarez et al, "Greater focus needed on methane leakage from natural gas infrastructure" (2012) 109:17 PNAS 6435-6440.

placing crucial emphasis on difficult-to-measure emissions in other countries, and potentially creating friction with its trade partners. Alternatively, BC could scale back its life cycle promise and focus on emissions within BC.

Overall Conclusions

In summary, the LCAs suggest that LNG from AB or BC natural gas may have lower upstream greenhouse gas emissions than the natural gas sources studied in previous LCAs; however, they are based on incomplete data. Until better data is available to fill in the current gaps, it will be impossible to conclude whether Canadian upstream emissions are, indeed, lower than emissions estimated from other North American LCAs. Additionally, it is recognized that measurements across North America are limited by sample size, highlighting the need to develop more robust estimates for regulatory purposes.

Regardless of which estimate is used, the LCA also shows that over three quarters of life cycle greenhouse gas emissions from liquefied natural gas occur after the LNG has been liquefied and exported to other countries, which raises significant questions about BC's legal jurisdiction to address these overseas emissions. Ultimately, we conclude that BC's ability to address these emissions will remain unsettled in the near term because climate change is pressuring traditional limits on provincial and national jurisdiction that have, in the past, been enforced only by trade law. On the other hand, regulators in Canada have significant opportunities to adopt cost-effective regulations to control greenhouse gas emissions from natural gas production and can work toward international partnerships that may lower greenhouse gas emissions from the entire LNG life cycle.

Finally, the LCA shows that the net impact of LNG on greenhouse gas emissions worldwide depends crucially on which sources of electricity it displaces, which in turn depends on which markets import LNG. Many have argued that LNG will replace coal power in other countries or, alternatively, displace low-carbon sources such as nuclear and renewables. As a first approximation, we examine what the impact of LNG would be if it displaced a representative cross-section of an importer's power sector. That is, LNG would displace coal in a country entirely reliant on coal and would displace wind and solar in a country entirely reliant on those sources. We show that, under this assumption, China, India and Taiwan would lower global greenhouse gas emissions by importing Canadian LNG, but European and South American countries would raise global greenhouse gas emissions. These results rely on the assumption that natural gas is utilized for electricity generation. Future research should not only move towards better estimates but also towards examining the effects of alternative end uses.

Appendix A

The summaries of the North American LCAs reviewed are presented in the following subsections.

Howarth: Howarth's study[89] primarily relies on point values gathered from previous studies and does not conduct any further data collection. The study is not exhaustive and only broadly examines five activities and processes of the shale gas life cycle. The main focus was on inventorying fugitive methane emissions, which were reported as a low and high percentage of methane (CH_4) produced over the well life. Howarth's analysis contains several contentious points that are worth noting. Since its publication, researchers have debated the study's scientific soundness and accuracy. The total life cycle emissions arising from shale gas is calculated using Shindell's 20 year GWPs, a higher value than the conventional 20 year GWP published by the IPCC in 2007. This is compared to the value calculated from using the 100 year GWP from the 2007 IPCC report. Secondly, the upper limit of the transport, storage, and distribution fugitive emissions reflects lost and unaccounted for gas reported by the state of Texas. Some argue this to be an unrepresentative value, as discrepancies in gas volume could be due to various reasons unrelated to fugitive emissions. Howarth also did not consider generation efficiencies in his analyses, nor did he account for methane control technologies, amplifying the relative effects of natural gas-fired electricity. Finally, it is important to note that the completion emissions data is representative of both shale (Haynesville and Barnett) and tight sand (Piceance, Uinta, Den-Jules) production, and the cited sources are higher than the other reviewed studies and do not account for capture or flaring.

Stephenson: A model was constructed by Stephenson *et al*.[90] that focused on highlighting the differences between unconventional and conventional gas production and systems. Gas treatment after production was assumed to be the same regardless of the gas source and emissions were bundled into a single category called "Common Elements". Emissions from the transmission system were also considered to be the same for both shale and conventional gas sources. Base case values were gathered for use in this current study. Parameters specific to shale gas production include well drilling, treatment and sourcing of fracturing water, and flaring. In the base case, 51% of the methane released during well completion is assumed to be flared. This value was estimated by the EPA in 2010, and derived by extrapolating the estimation that 51% of all unconventional gas wells were located in Wyoming, where flaring is required. In terms of regional geography, Stephenson's data is representative of North American shale gas. Greenhouse gas emissions of co-products were allocated proportional to their respective energy contents.

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[89] Howarth, Santoro & Ingraffea, *supra* note 4 at 679-690.
[90] Stephenson, Valle & Riera-Palou, *supra* note 4 at 10757-10764.

Weber: Estimated values from six previous studies were examined by Weber and Calvin[91] and a selected set was used as inputs in a Monte Carlo analysis. Understandably, the system boundaries and analysis methods across the six studies differed. Adjustments were made according to the authors' best judgment to ensure that the data collected were compatible. Emissions associated with liquids unloading were removed from those studies that included it, and co-product allocations were removed where needed to ensure uniformity across data sets (for example, in Stephenson *et al.*[92]). Where possible, the authors separated lease fuel and plant fuel from the emission categories.

Venkatesh/Jiang: The studies of Venkatesh *et al.*[93] and Jiang *et al.*[94] are complementary. Jiang *et al.* focused on the aspects unique to shale gas production in the Marcellus shale. These were grouped into the "pre-production" stage, and includes activities related to the well site investigation step through well completion. The study of Venkatesh *et al.*[95] considered the stages of natural gas production after the "pre-production stage", and includes the production, processing, transmission, distribution, and combustion stages. The activities associated with these stages were considered to be similar for all sources of natural gas. Jiang's study is a hybrid process emission estimates and economic input output (EIO) life cycle assessment, in which the emissions associated with certain processes were estimated using the EIO-model. The flaring rate considered in the base case of this study is 76%. The results of Jiang *et al*.[96] were then added to those of Venketash *et al.*[97] to form a complete life cycle of shale gas. Although Jiang *et al.* focused on the Marcellus, the data of Venkatesh *et al*.[98] is representative of all sources of domestic natural gas.

Fulton: Fulton *et al.*[99] conducted a top-down analysis aimed at studying the greenhouse gas footprint of gas-fired electricity in the US. The EPA's 2011 greenhouse gas emissions inventory for natural gas, representative of the year 2009, was used as the baseline emissions data. In this data set, CH_4, N_2O and combustion CO_2, and non-combustion CO_2 are categorized separately. Emissions were not broken down further than the four broad stages of production, processing, transmission, and distribution. This baseline data was then adjusted to represent domestic natural gas production more accurately. Emissions associated with production and processing were increased to account for the proportion of liquefied natural gas imports making up the domestic natural gas inventory. Although distribution data was not collected in the current study,

91 Weber & Clavin, *supra* note 4 at 5688-5695.
92 Stephenson, Valle & Riera-Palou, *supra* note 4.
93 Venketash et al, *supra* note 4 at 8182-8189.
94 Jiang et al, *supra* note 4.
95 Venketash et al, *supra* note 4.
96 Jiang et al, *supra* note 4.
97 Venketash et al, *supra* note 4.
98 *Ibid*.
99 Fulton et al, *supra* note 4.

distribution emissions were decreased to reflect the fact that natural gas does not always pass through the distribution system. Finally, natural gas is often co-produced during petroleum production. A portion of the methane emissions associated with petroleum production was allocated to coproduced natural gas. The adjusted emissions were normalized against the heat content of the volume of gas delivered to consumers. As a consequence of using the EPA's inventory as a basis for the analyses, the data already accounts for methane reductions resulting from flaring, NESHAP regulations, and EPA's NG STAR processes.

JISEA: The basis of the emissions inventory for production and processing stages was built largely on detailed emissions from three emissions inventories developed by the Texas Commission on Environmental Quality (TCEQ). These stages describe activities related to gas extraction at well heads through gas processing activities to produce pipeline ready gas. Gas composition analyses specific to the regions were then used to disaggregate volatile organic compound emissions from methane and CO_2 emissions. As the JISEA[100] study relies heavily on TCEQ documentation, the analysis focuses on the Barnett shale. For activities in the pre-production and transmission stages, literature data was used to estimate emissions. Emissions were totaled and then normalized by the heat content of gas produced annually. Co-products were proportionally allocated emissions based on energy content. Emissions associated only with storage and handling of co-products were not included in the LCAs. Although construction and infrastructure emissions were included in the analyses of the JISEA[101] study, these emissions were omitted in the current study.

NETL: The NETL[102] study is an inventory-based study that analyzes multiple sources of conventional and unconventional gas. The shale gas analysis is based on data representative of only the Barnett play, and temporal-wise, is most representative of the year 2009. The authors assumed a 15% flare rate for well completion emissions (gas released from the wellhead and gathering equipment), while flare rates during processing and from valves and other equipment leaks is assumed to be 100%. The authors also assumed that liquids unloading are not relevant for unconventional sources of gas. Workovers were included in the analysis of shale gas production. Co-products produced were allocated greenhouse gas emissions proportional to their energy contents. The NETL[103] study concludes that natural gas-fired baseload power production has life cycle greenhouse gas emissions 42 to 53% lower than those for coal-fired baseload electricity, after accounting for a wide range of variability and compared across different assumptions of climate impact timing. The lower emissions for natural gas was attributed to the higher average efficiency for natural gas-fired power plants compared to coal-fired power plants, and a higher carbon content per unit of energy for coal than natural gas.

[100] Logan et al, *supra* note 4.
[101] *Ibid*.
[102] NETL, *supra* note 4.
[103] *Ibid*.

Burnham/ANL: The Burnham[104] and the ANL[105] studies are complimentary. The ANL study documents the addition of the shale gas pathway to Argonne's previously developed GREET (Greenhouse gases, Regulated Emissions, and energy use in Transportation) model. Burnham continues a similar discussion, though his study focuses more on the application of GREET to estimate and analyze greenhouse gas LCA emissions of shale gas, coal, conventional gas, and petroleum. The key parameters entered into the model were gathered largely from EPA documents and US Government Accountability documents. Both documents report the same results and emissions estimations for shale gas. The base case flaring rate for well completions was assumed to be 41%, and liquids unloading was only associated with conventional gas production. Besides flaring, emissions factors were adjusted to account for methane reductions considered by the EPA in the 2011 greenhouse gas Inventory. In the annual EPA greenhouse gas inventories, methane reductions resulting from NG STAR practices, NESHAP regulations, relevant state regulations, and flaring are subtracted from baseline values of "Potential CH_4 Emissions". NESHAP and NG STAR data included in EPA documentation were therefore analyzed and the emission factors were adjusted per the author's best interpretation to best represent "real world conditions".

It is noted that on October 30, 2009, the US EPA published a rule for the mandatory reporting of greenhouse gases from large sources in the US. The rule, 40 CFR (US Code of Federal Regulations) Part 98, referred to as the Greenhouse Gas Reporting Program (GHGRP) applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO_2 underground for sequestration or other reasons. Under this rule reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. EPA started using the data to improve the national estimates in its inventory report of 2013.[106]

Laurenzi and Jersey: The study by Laurenzi and Jersey[107] presents the results of a LCA of Marcellus gas based on ExxonMobil field data for drilling, completion, production, and power plant operations. It focuses on the carbon and water footprints of Marcellus gas from "well to wire" (i.e. drilling the well to generation of electricity at a power plant). The study presents the upper and lower limits of the greenhouse gas and water footprints, and the sensitivity analyses of the results, identifying uncertain variables or features of the Marcellus gas LCA that are the most likely to have a significant effect on the total greenhouse gas emissions. It also compares their results for the Marcellus gas footprints with results of other studies of coal, conventional gas and shale gas. The assessment of greenhouse gas was limited to CO_2, CH_4 and N_2O, and emissions were assessed in units of CO_2-equivalents as specified by the IPCC's Fourth Assessment

[104] Burnham et al, *supra* note 4 at 619-627.

[105] ANL, *supra* note 4.

[106] US EPA, *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2011*, Report No EPA 430-R-13-001 (Washington, DC: EPA, 2013).

[107] Laurenzi & Jersey, *supra* note 4.

Report (AR4), using the 100 year GWP. For segments where insufficient amount of data existed, Laurenzi and Jersey utilized EPA emission factors or regulatory emission limits. A NETL model of a combined-cycle gas turbine plant having a 50.2% efficiency (HHV basis) was adopted for a base case assessment of the power generation plant. Results of the base case LCA showed that 466 kg CO_2e/MWh was generated using a 100 year GWP basis, with 77.9% of greenhouse gas emissions occurring at the power plant. Their results also showed that greenhouse gas emissions are most sensitive to estimated ultimate recovery.

GHGenius: The GHGenius[108] is a model that was developed for Natural Resources Canada. It is based on the 1998 version of Dr. Mark Delucchi's Life cycle Emissions Model (LEM). GHGenius is capable of analyzing the emissions of many contaminants associated with the production and use of traditional and alternative transportation fuels (GHGenius Model, Vol. 1). The GHGenius model is capable of estimating life cycle energy balances, the emissions of the primary greenhouse gases and the criteria pollutants from combustion sources. The model can also predict emissions for past, present and future years through 2050 using historical data or correlations for changes in energy and process parameters with time that are stored in the model. The GHGenius contains information from sources in Canada, the US, Mexico, India and a few other countries. For the results presented in this report, the model was run with Canada selected as the country of interest, 2012 selected as the year of interest, and IPCC 2007 values selected for the GWPs. The option for carbon capture and sequestration was not included in running the model.

BC/AB: British Columbia (BC) and Alberta (AB) natural gas production and emissions data were obtained public data compiled by the BC government.[109] All data presented in this report were extracted from the web. Data presented for BC and AB were subject to different reporting thresholds, ultimately leading to different greenhouse gas estimates. The BC Reporting Regulation has a 10 kt reporting threshold that applies to facility-level emissions from overall company releases, while AB and Canada both use a 50 kt reporting threshold. The BC data includes 112 facilities. A reporting aggregation approach similar to that used by BC is used by the US, but with a 25 kt threshold. The US and BC use very similar prescribed quantification methods, while for AB and Canada the methods follow guidance materials. Thus, the BC and US data are expected to be of higher quality and more consistent than that of AB due to the higher reporting threshold applied for the latter. Greenhouse gas releases from distribution in AB are reported voluntarily by only one company; hence, the data reported for these operations are unlikely to be representative.

[108] GHGenius, "Model", online: <http://www.ghgenius.ca/downloads.php>.
[109] Environment Canada, *supra* note 2.

Appendix B

For the LNG transport segment, the emission factor (per nautical mile) used in the DOE/NETL report[110] was applied and scaled according to the distances (in nautical miles) from Kitimat, BC to the various export destinations. The resulting LNG transport emission factor for each country, based on the distance between Kitimat, BC and each country was used in Figure 8. However, in Figures 2, 5, 6 and 7, a single LNG transport emission factor was required. This was achieved by taking a weighted average of the emission factors for the destination countries shown in Figure 8, based on the size of the export markets (and thus the relative potential of exporting to those markets).

Table 4: Weighted average emission factor for LNG transport from Kitimat, BC to various countries based on the emission factor used by the DOE/NETL report[111]

Country	Total Electricity Generation (2010)	Distance	LNG Transport GHG Emissions Factor	Weighted Average for LNG Transport GHG Emissions Factor
	(TWh)	(N. Miles)	($kgCO_2e/MWh$)	($kgCO_2e/MWh$)
China	3904	4794	25.1	9.3
India	904	8377	43.8	3.8
Japan (2012)	1094	3637	19.0	2.0
South Korea	497	4708	24.6	1.2
Spain	300	9159	47.9	1.4
UK	378	9134	47.8	1.7
Belgium	94	9054	47.4	0.4
Argentina	111	8180	42.8	0.4
Brazil	507	8565	44.8	2.2
Taiwan	244	5200	27.2	0.6
France	564	8827	46.2	2.5
Turkey	211	10285	53.8	1.1
Germany	622	9327	48.8	2.9
				29.4

[110] TJ Skone et al, *supra* note 3.
[111] *Ibid*.

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May 2015