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# Country-Level Life Cycle Assessment of Greenhouse Gas Emissions from Liquefied Natural Gas Trade for Electricity Generation

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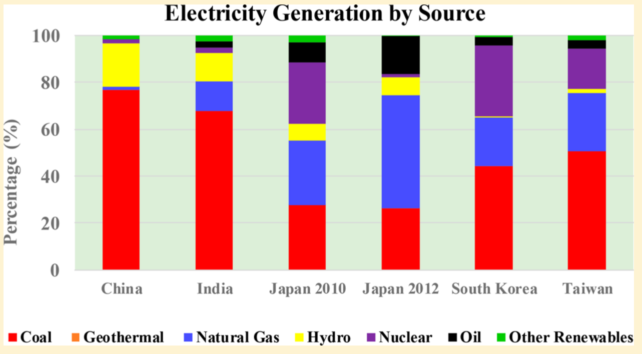
Supporting Information



**ABSTRACT:** In the determination of the net impact of liquefied natural gas (LNG) on greenhouse gas emissions, life cycle assessments (LCA) of electricity generation have yet to combine the effects of transport distances between exporting and importing countries, country-level infrastructure in importing countries, and the fuel sources displaced in importing countries. To address this, we conduct a LCA of electricity generated from LNG export from British Columbia, Canada with a three-step approach: (1) a review of viable electricity generation markets for LNG, (2) the development of results for greenhouse gas emissions that account for transport to importing nations as well as the infrastructure required for power generation and delivery, and (3) emissions displacement scenarios to test assumptions about what electricity is being displaced in the importing nation. Results show that while the ultimate magnitude of the greenhouse gas emissions associated with natural gas production systems is still unknown, life cycle greenhouse gas emissions depend on country-level infrastructure (specifically, the efficiency of the generation fleet, transmission and distribution losses and LNG ocean transport distances) as well as the assumptions on what is displaced in the domestic electricity generation mix. Exogenous events such as the Fukushima nuclear disaster have unanticipated effects on the emissions displacement results. We highlight national regulations, environmental policies, and multilateral agreements that could play a role in mitigating emissions.




## 1. INTRODUCTION

Climate change and growing demand for energy are two of the most pressing challenges in energy policy today due to the increasing risks to human and natural systems predicted by climate models.[1] Thus, a central question for energy policymakers is what role natural gas, a cleaner-burning fossil fuel, should play in meeting the world's ever-increasing energy demand. Technological advances arising from the combination of horizontal drilling and hydraulic fracturing have created a recent boom in North American natural gas production, bringing the monthly average Henry Hub prices down from spikes over \$12/MMBtu in 2008 to below \$2/MMBtu in 2016.[2] The resulting oversupply of natural gas in North America has become an impetus for the natural gas industry to find alternative markets across the globe. Global gas demand is expected to grow at an annual average rate of 2% between 2014 and 2020,[3] providing new opportunities for expanding LNG markets.

Electricity generation is one of the demands for imported natural gas, where reductions in greenhouse gases may be realized; however, the overall effects of imported natural gas on these emissions depend on the electricity being displaced in the import country. The retirement of coal-fired power and addition of natural gas-fired electricity results in reductions of numerous pollutants (e.g., mercury), and up to 60% of the greenhouse gas emissions intensity for power generation.[4] The effect of LNG import on other forms of electricity generation in different countries is complicated by numerous political, economic, and scientific uncertainties. For example, demand increases may be expected in regions where environmental regulations result in coal plant retirements; demand may be hampered in regions where renewables are competitive because of geography or government policy; demand may be slowed in regions with lax regulations where coal is cheap.[3] At the same time, the ultimate magnitude of the emissions associated with natural gas production systems is still unknown.[5] While numerous life cycle assessments (LCAs) have quantified the

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emissions associated with the supply chain of natural gas and power plants,[6−17] results face scientific uncertainty driven by a number of factors such as the challenge in capturing the available large population (e.g., thousands of wells) for facility emissions measurement, and the effects of "super-emitters" on total emissions.[5] The assessment of the greenhouse gas emissions from the natural gas supply chain were compiled from existing studies, the uncertainty in upstream emissions is noted by our representation of the variability in results across upstream studies.

While the energy, economic, and environmental implications of U.S. and Canadian natural gas production systems and LNG export have been well researched,[5,16−22] Our present understanding of life cycle emissions is complicated by differences in system boundaries and assumptions across studies. To address this challenge, the National Renewable Energy Laboratory developed an analytical procedure called harmonization where models, assumptions, and boundaries are modified for consistency (e.g., Heath et al.[23]). Canadian natural gas data have yet to be compared to existing studies or examined in light of harmonization techniques. Further confounding our understanding of life cycle emissions, measurements are not always directly comparable due to different reporting thresholds for facility-level emissions (25 kilotonnes (kt) $CO_2$ e a year for the U.S.;[24] 10 kt for British Columbia (BC);[21] 50 kt for Alberta[22]). While most studies have focused on upstream assessment, domestic power generation, influence of LNG transport to different countries, or have made simplified assumptions about the use of LNG in importing nations (Table 1), there has yet to be a LCA that accounts for the influence of infrastructure and power plant efficiency in the country where the fuel is imported. In this study, we develop a LCA that highlights the variability in results of upstream emissions across existing studies and performs a comprehensive examination of the differences in greenhouse gas emissions resulting from country-level power generation and distribution infrastructure in importing nations. Table 1 provides a comparison of the contributions of previous studies relative to the contribution of this study. In recent years, several new studies have improved our knowledge of methane emissions from natural gas production. As a result, it is noted that the harmonization with older studies may not always reflect the current understanding of uncertainty in methane emissions, but rather the variability in the historical understanding of these uncertain emissions.

In this study, we have three contributions: (1) we build upon existing data sets to better understand our existing knowledge of the life cycle of LNG export, (2) we examine the effects of the import country's generation fleet and infrastructure on the life cycle emissions of electricity delivered, and (3) we perform a scenario analysis to better understand the uncertainty underlying the emissions displacement assumptions. Life cycle emissions of delivered electricity were determined at the country-level by compiling the upstream emissions associated with the LNG supply chain and the expected emissions for the country-level generation and distribution. The effects of a number of model inputs were assessed for each country, including the power plant efficiency, electricity T&D losses, and ocean transport distances. The implications of displacing emissions associated with different categories of fuel mixes in these potential export markets are examined in various scenarios. Finally, previous assessments of LNG export seldom include Canadian LCA results in a meaningful way. While the focus is on export from British Columbia, the results provide a basis for understanding challenges that other exporting and importing nations will experience in addressing greenhouse gas emissions that occur from the expansion of global LNG markets.

## 2. MATERIALS AND METHODS

We aim to improve the present knowledge on LNG export by undertaking a more detailed analysis of country-level emissions and investigation of differences across life cycle studies. Our approach includes (1) a review of potential markets for LNG export, (2) a life cycle assessment of emissions from LNG import used in electricity generation including testing the sensitivity of model results to country-level inputs, and (3) emissions displacement scenarios to test previous assumptions about what electricity is being displaced.

**Viable LNG Markets.** The global LNG demand outlook suggests several opportunities for North American exporters to target potential markets in Asia, Europe, and Latin America.[25−27] European and Latin American markets could potentially be served by facilities in the East Coast of Canada[28] while Asia-Pacific markets are in closer proximity to LNG projects located in Western Canada. We identify 12 viable markets for LNG export from Canada (Figure 1) based on geographical factors as well as current and planned regasification capacity, natural gas demand outlook, share of fossil fuels in the electricity generation mix, level of economic development, financial capability, and nuclear and coal decommissioning or enforcement of other relevant energy and climate change policies.[25,26,28,29]

Profitability drives decision-making for LNG trade, where Asia-Pacific markets have consistently maintained the highest landed LNG prices (Figure 1). Natural gas is not a global commodity, having the three regional markets of natural gas, namely North America, Europe, and Asia-Pacific. Approximately 70% of the natural gas is traded by pipelines, while the remaining 30% is traded by LNG carriers.[29] Inter-regional trade is expected to grow by 40% between 2014 and 2020, with LNG accounting for 65% of the increase.[3] Large increases in demand growth are expected in Asia, namely China, Japan, South Korea, and India. The price trends highlight the relevance of the two price mechanisms used for international trade of natural gas. The North American region uses the gas-on-gas mechanism linked to competitive gas market spot prices which respond according to natural gas supply and demand. Driven by the shale gas boom, the region has shown the lowest average market price of about \$3.5/MMBtu (USD) between third quarter of 2008 and second quarter of 2016. On the other hand, in the Asia−Pacific region, and to a lesser extent, in Europe, the natural gas prices are indexed to oil market spot prices that were much higher for the period in consideration, averaging about \$7.7/MMBtu (USD) for Europe and about \$10.5/MMBtu (USD) for the Asia-Pacific region over the time period noted. Recent studies estimate that the cost of supplying LNG to Japan could be as much as \$11.20 per million cubic feet (mmcf), including toll, loading and transportation.[28]

It is estimated that out of the 19 export license applications submitted to the National Energy Board as of the fifth of September in 2014, Western Canada has the potential to export about 18.4 million tonnes per annum (MMTPA) of LNG to potential markets (particularly, the fast-developing Asian-Pacific market).[25] The estimation considers the above factors as well as


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Table 1. Summary of Previous Studies Examined Compared to the Contribution of This Study

| factors included | Howarth[6] | other previous studies: Stephenson,[7] Weber,[8] Jiang,[10] Fulton,,[11] JISEA,[12] Laurenzi,[15] NETL[16] Hultman,[32] Skone[33] | Burnham,[13] ANL[14] | DOE/NETL (2014)[17] | Abrahams[38] | Coleman | GHGenius | this study |
|---|---|---|---|---|---|---|---|---|
| pathways | upstream, combustion of fuel | upstream, well to wire | upstream, well to wire, well to wheel | upstream, well to wire | upstream, well to wire | upstream, well-to-wire | upstream, well-to-wire | upstream, well to wire |
| LNG life cycle | not considered | not considered | not considered | considered | considered | considered | considered | considered |
| LNG import and export path | not considered | not considered | not considered | includes (1) export of U.S LNG to Asia (Shanghai) and Europe (Rotterdam) , (2) export of Algerian LNG to Europe (Rotterdam) by tanker and export of Australian LNG to Asia (Shanghai) by tanker, (3) export of Russian natural gas to Asia (Shanghai) and Europe (Rotterdam) via pipeline, and (4) coal extraction from Asia and rail transport to domestic plants in Asia, coal extraction from Europe and rail transport to domestic plants in Germany | examines export of LNG from U.S. to Japan, South Korea, India, China, UK and The Netherlands | export of British Columbia LNG to Belgium, Germany, Spain, UK, Turkey, Argentina, Brazil, China, India, Japan, South Korea and Taiwan | not considered | examines export of LNG from B. C. to Belgium, Germany, Spain, UK, Turkey, Argentina, Brazil, China, India, Japan, South Korea and Taiwan |
| country-specific aspects | not considered | not considered | not considered | although study is meant to examine international LNG exports, it does not consider country specific factors. Assumes foreign power plant efficiency is similar that of the U.S. electricity transmission losses assumed to be 7% for all countries | liquefaction, shipping distance from three U.S ports, and regasification segments are examined. power plant efficiency distribution is estimated based on three NGCC Power plant efficiencies of 41% (min), 46% and 51% (max) | GHG emissions estimated from country specific electricity generation mix. Ocean transport emissions factor is based on a weighted average of emissions by most likely export volume. Most downstream segments share common emission factors, assumed to apply across countries | models can be run for countries like Canada, US, Mexico and India | examines key differences in LCAs of LNG export for power generation in 12 countries. Three segments were assessed: LNG transport by ocean tanker, power plant combustion, and electricity T&D |
| emissions displacement scenarios | not considered | not considered | not considered | focuses on differences in transport emissions of natural gas export (either by pipeline or tanker) and coal (by rail). | displacement of local coal and Russian natural gas only | displacement of country's current electricity generation portfolio mix by B.C. LNG | not considered | includes three emissions displacement scenarios: total electricity mix cross-section, dispatchable electricity, and marginal electricity. also comments on the possibility of renewable emissions scenario. |
| methods | point estimates | Stephenson (bottoms-up emissions compilation via parameter and emissions factors), Weber (segment emissions estimated via Monte Carlo), Laurenzi (segment emissions estimated via Monte Carlo, statistical analysis), Jiang (Monte Carlo), JISEA (inventory approach, broadly, emissions from fuel segments summed and divided by energy content of produced | segment emissions estimated via probability distribution functions | unit process compilation NETL's LCA tool | segment emissions estimated via probability distribution functions | scenario analysis | uses Monte Carlo simulations | conducts country level scenario analysis using spread of published upstream data supplemented with |



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Table 1. continued

| factors included | Howarth[6] | other previous studies: Stephenson,[7] Weber,[8] Jiang,[10] Fulton,[11] JISEA,[12] Laurenzi,[15] NETL[16] Hultman,[32] Skone[33] | Burnham,[13] ANL[14] | DOE/NETL (2014)[17] | Abrahams[38] | Coleman | GHGenius | this study |
|---|---|---|---|---|---|---|---|---|
| | | gas), Fulton (tops down inventory analysis), Hultman (bottoms up emissions compilation parameter/missions factor), Skone and NETL (Unit process compilation using NETL's LCA tool) | | | | | | country specific point estimates |
| export country considered | American | American | American | American | American | Canadian | not applicable | Canadian |
| gas extraction method | conventional and unconventional gas | conventional and unconventional gas | conventional and unconventional gas | unconventional gas | U.S. natural gas development (unconventional and conventional mix) | conventional and unconventional gas | discusses total natural gas supplies | unconventional and conventional gas |

offtake agreements of LNG projects planned to be built in British Columbia.[26,30]

Several data and information gaps were determined through reviewing LNG prices. 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 began importing LNG in 2008, China began in 2006 and became a net importer in 2007. Second, data corresponding to Mexico, Japan, Korea, India, Spain, Belgium, UK, and U.S. Lake Charles and Cove Point are not available for three months: February 2011, July 2012, and December 2013.

**Country-Level LCA.** Data from existing LCAs emissions were compiled to characterize upstream natural gas emissions for those countries importing LNG for assumed use in power generation. A number of factors have been found to differ across studies, including whether the natural gas is conventional or unconventional, assumptions about the frequency of liquids unloadings, workovers, and/or recompletions, the use of emission controls (such as green completions), assumptions about the estimated ultimate recovery, the scope of methane leakage estimates, the time frame considered in calculating the global warming potential (GWP) of methane (100 year IPCC AR4 estimates of GWPs were applied), assumptions about power plant efficiency, and presence of coproducts during natural gas production.[6−11,13,15,23,25,31−33] This study builds upon the set of data of life cycle emissions reviewed in Coleman et al.,[25] adds other studies[32,33] and completes a simplified harmonization (see Supporting Information (SI)). A full harmonization was not completed; however, data from each of the studies were placed into segments that were most comparable and converted to grams of carbon dioxide equivalent per kilowatt-hour in higher heating values ($gCO_2$ e/kWh, HHV). Among the studies reviewed, the data collected and utilized in this study were from those that present greenhouse gas emissions data from the U.S. specific to shale and unconventional gas, but the studies that present emissions data from Canada were representative of all natural gas production. Since natural gas fuels the marginal generators during most peak and some off-peak periods in many regions,[34] the data compare Canadian natural gas to marginal production in the United States (shale gas contributes new production in the United States and can therefore be considered the marginal unit of natural gas production). We examine country level emissions on a per kWh delivered basis to demonstrate the potential variation of life cycle estimates by country, including delivery to customer. The life cycle emissions per unit of power delivered will depend on technical differences in the generation fleets and infrastructure as well as the development of government policies and regulations.

Key factors that vary across countries were identified and examined, including electricity T&D losses, natural gas fleet efficiency, and ocean transport distances (see SI). The average 2014 natural gas fleet efficiencies for all countries except China, which was unavailable, were obtained from the World Energy Council (WEC).[35] The NGCC thermal efficiency for China was taken from Kahrl et al.[36] Country-level averages of T&D losses were also sourced from the WEC.[35] Losses in the electrical T&D network were added onto the total emissions of each study. Emissions arising from power plant operations were calculated based on a carbon intensity factor of 50 $gCO_2$ e/MJ[12] of combusted natural gas, and each country's respective natural gas plant efficiencies. The LNG transport emissions were scaled by distance based on emission factors by distance,


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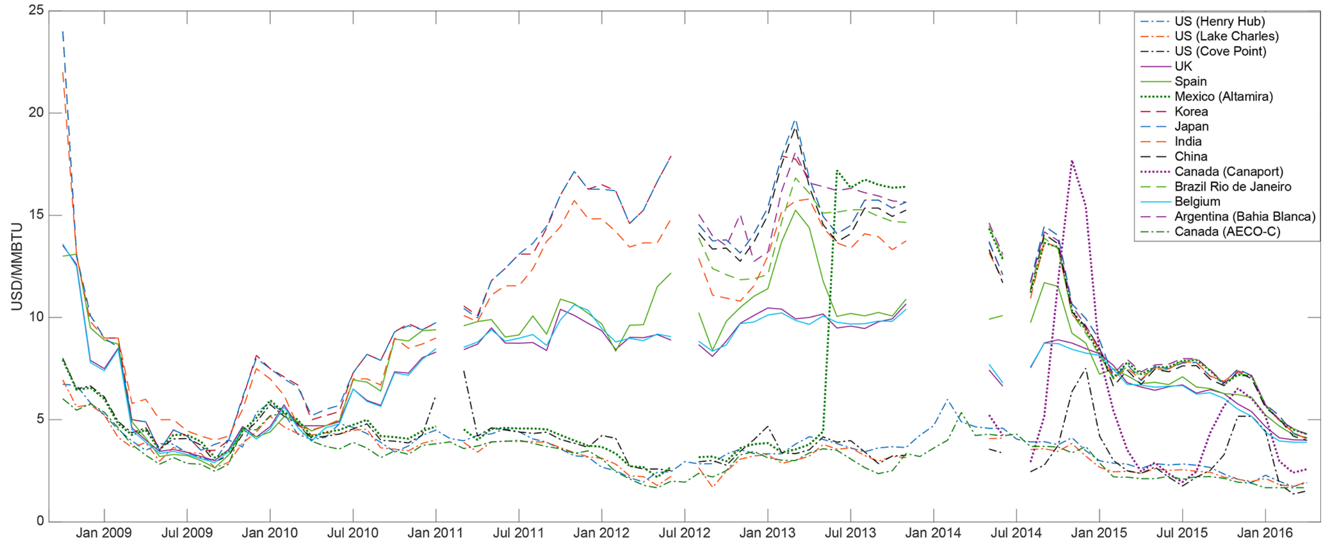


**Figure 1.** Available historical natural gas prices for different markets, 2008−2016.[2,29] These have not been converted to current day, but rather reflect price reported during the month noted. Gaps in trends reflect where data were not available.

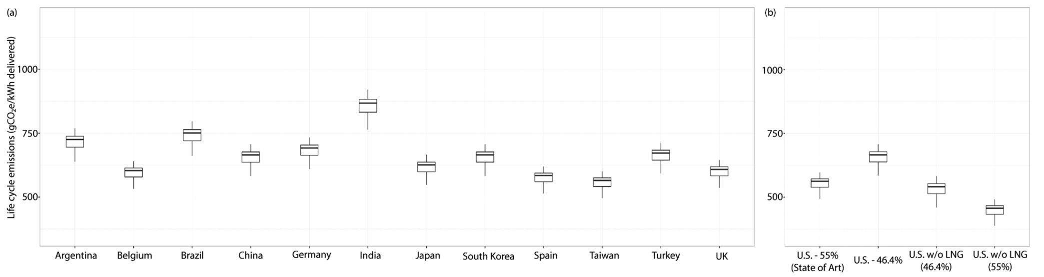


**Figure 2.** Life cycle greenhouse gas emissions of LNG export, adjusted with country-specific factors of fleet efficiency, ocean transport and T&D losses. (a) presents international results, while (b) presents results specific to North America The first two boxplots in (b) represent total LNG life cycle emissions, assuming 46% power plant efficiency (representative of average U.S. efficiency) and 55% power plant efficiency (the state of art). The last two boxplots in (b) represent natural gas life cycle GHG emissions when stages associated with liquefaction and exports are excluded. The boxes in the figure represent the interquartile range (IQR), which is the difference between the third quartile (Q3) and the first quartile (Q1). The line in the box represents the median, the whiskers represent the maximum and minimum.

(relating emissions to nautical miles) from Kitimat, BC.[17] The route to Europe from British Columbia was assumed to cut through the Panama Canal, which was found to be the shortest available ocean route.[37]

**Emissions Displacement Scenarios.** Previous studies either assumed that coal or natural gas would be displaced[17,38] or that a cross-section of the electricity mix would be displaced.[25] This assumption does not account for country-specific policies, environmental regulations, demand and supply dynamics of specific fuels, competitive pricing of different types electricity generation, or geo-political events. Such factors can have a great influence on the outcome of the result of emissions displacement. We selected case studies for scenario development in order to understand better the influence of emissions displacement assumptions on life cycle results. Case studies were selected from the list of potential markets based on three criteria: (1) landed natural gas prices, (2) potential demand growth, and (3) market size. Indeed, we assessed the five largest importing countries of LNG in the Asia−Pacific region,[9] namely China, India, Japan, South Korea, and Taiwan. The Asia−Pacific market as a whole represents 75% of global LNG imports, highlighting its importance in the growth of LNG trade. Although Japan is presently the main importer, China, and India have experienced recent increases of LNG demand that are forecasted to continue into the future.[29]

We examined three emissions displacement scenarios assuming that the imported LNG is used in electricity generation and displaces the following power sources: either (1) total electricity mix cross-section, (2) dispatchable electricity, or (3) marginal electricity. Total electricity mix cross-section is the electricity generated from all available sources in a country, while dispatchable electricity is one that can be turned on and off to meet the changing electricity demands. Dispatchable electricity sources here refer to a combination of nuclear, hydro, coal, oil and natural gas. For this study, we assume that LNG from Canada is the fuel of choice being considered by importers (i.e., it out-competes other sources or other sources are not available), so displacement of local natural gas only was not a focus of our displacement scenarios.

The focus of the marginal scenario was on long run marginal electricity, where increases in capacity are considered due to the longer time horizon of the scenarios. For simplicity, the long run marginal fuel source of a country was taken to be most abundant electricity fuel source in the generation mix of that country. Coal was taken to be the long run marginal fuel source for China, India South Korea, and Taiwan, and oil for that of Japan. The underlying assumption is that decisions are made similar to past decisions, based on resource availability, cost, and static policy and regulation. Japan is an exception, where


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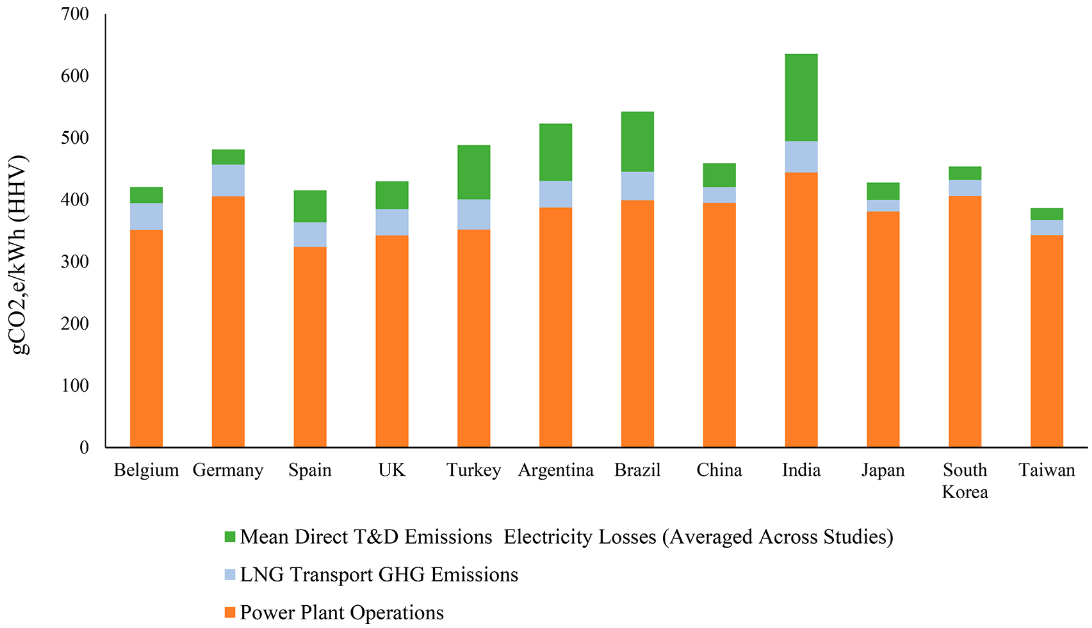


**Figure 3.** Mean greenhouse gas emissions arising from only the segments which rely on country-specific values.

the marginal fuel source experienced the highest percentage growth after the Fukushima nuclear disaster. In this case, a fuel source providing a quarter of the country's electricity (nuclear) was rapidly changed and replaced with other sources. One limitation to this approach may be that the costs of renewable energy are becoming increasingly competitive. High import prices of natural gas have led to the decreased competitiveness of LNG when compared to cheap, local coal or the decreasing costs of renewables.[3] While our scenarios focus on displacing a representative cross-section, dispatchable electricity, and marginal electricity, in the absence of policies to incent renewable energy, imported natural gas that is cheap enough may displace renewable energy. We addressed the possibility of displacing renewable power in the SI.

## 3. RESULTS AND DISCUSSION

**Country-Level LCA.** We present a distribution of results from 14 existing studies on upstream natural gas emissions and apply country-specific assumptions on fleet efficiency, ocean transport, and T&D losses for 12 potential markets (Figure 2). Of note, India's average gas plant fleet efficiency (41%, HHV) and the rate of its electricity T&D losses (20%) were reported as the lowest and highest respectively, among the countries assessed. Consequently, natural gas exported to India is expected to have the highest life cycle emissions intensity when used for power generation (average of 855 $gCO_2e/kWh$), while that exported to Belgium (average of 595 $gCO_2e/kWh$), Spain (average of 575 $gCO_2e/kWh$), and Taiwan (average of 557 $gCO_2e/kWh$) for use in power generation was found to have the three lowest life cycle GHG emissions intensities. Life cycle emissions results were also adjusted with generation and infrastructure factors specific to the U.S. to compare country-level results with the more simplified assumptions applied in previous studies using average ocean transport factors specific to Kitimat. The upstream data for all results include both BC and more detailed estimates from the United States for comparison, assuming that this range reasonably bounds potential upstream emissions (details provided in the SI). The results thus provide additional insight into the life cycle emissions from other regions in North America.

We present the life cycle results using U.S. generation fleet and infrastructure assumptions for comparison for two reasons: (1) for a better understanding of how our results compare to previous estimates that do not apply country-level factors and (2) for comparison to use in domestic North American generation (Figure 2b). First, we contrast the life cycle emissions of LNG when the power plant efficiency is assumed to be the average U.S. fleet efficiency against the efficiency of a state of art combined-cycle turbine. Specifically, the efficiency of the H-Class combined cycle gas turbine, published by General Electric to be the most efficient in the industry, is applied (55% HHV). Comparing the average fleet efficiency to the state-of-art efficiency demonstrates the benefits gleaned from the diffusion of new technology, highlighting the benefits of energy efficiency policies. The two LNG scenarios (including liquefaction and export stages) apply the weighted average ocean transport distance to destination markets estimated from Kitimat, BC (see SI). These two scenarios show the life cycle emissions as though BC was transporting LNG to the United States but it was traveling the same distance as to destination markets—the scenario that, implicitly, was being presented in previous work on this topic, which assumed that foreign destinations had the same generation fleet efficiency and T&D losses as the United States. Second, we present natural gas life cycle emissions excluding liquefaction and export stages (541 $gCO_2e/kWh$ on average at 46.4% HHV efficiency, and 457 $gCO_2e/kWh$ on average at 55% HHV efficiency). These results represent the estimated emissions intensity of natural gas used in North American power generation (without liquefaction or export). The results in Figure 2 highlight the need to include country-specific factors in LCAs for more meaningful results. We show that the fate of natural gas, whether it is imported, exported, or used domestically, has substantial differences in greenhouse gas consequences. Using LNG for domestic electricity generation may result in lower greenhouse gas emissions than exporting it for electricity generation in some countries; however, the magnitude of this difference depends


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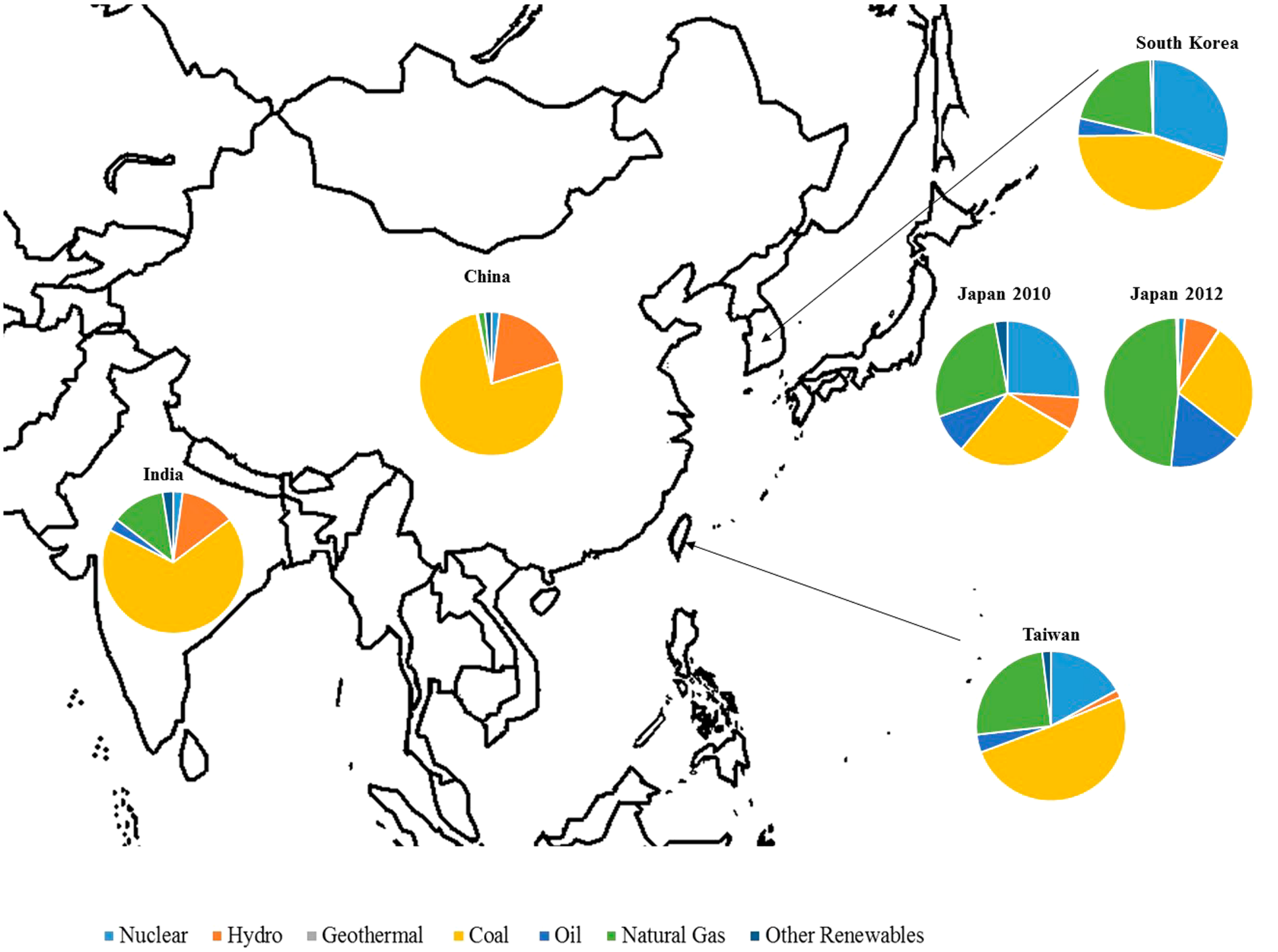


**Figure 4.** Electricity generation mix in selected import countries as of 2010. The total electricity generation in terawatt-hour (TWh) per year for each country are China, 3904; India, 904; Japan 2010, 1111; Japan 2012, 1094; South Korea, 497; and Taiwan, 244.

on the fuels displaced in both the domestic and the importing nations, as well as on the generation fleet efficiency and infrastructure of the nation where the fuel is consumed. Our approach provides a stronger baseline in the reduction of emissions when expanding trade, where national policy priorities can be determined by importers and exporters alike (e.g., energy efficiency for power generation or infrastructure improvements).

Given the complexity in interplay between factors that give rise to carbon emissions, our results describe the sensitivities of life cycle emissions to the differences in country-level factors specific to infrastructure and transportation. By varying key parameters which differ by country, we demonstrate the potential variability in emissions that could arise from electricity generation with LNG imported from Canada (or other exporting regions). It is critical to note that the significance of the results does not lie with the ultimate magnitude of the values, where uncertainties remain due to the evolving nature of upstream fugitive emissions measurements. Instead, the important conclusion is the potential for variability in carbon intensity of LNG across countries. Results suggest that the life cycle emissions intensity of LNG for power is indeed sensitive to country-level parameters, in addition to those noted in published studies. To crystallize the effect of country-specific factors on life cycle emissions, the downstream segments of the results were disaggregated from the upstream segments (Figure 3). The climate implications of these findings will be important for policymakers as they consider LNG export policies, trade agreements, as well as national electricity generation and environmental policies.

The true magnitude of greenhouse gas emissions arising from the combustion of imported LNG by each country is difficult to determine with absolute certainty. Although forecasts of international LNG imports exist in the literature, it is nonetheless extremely difficult to predict the specific end use of natural gas. The end use of natural gas and the location of this end use is determined by a complex interaction of governmental policies and regulatory landscape, existing infrastructure, and economics unique to each country. Similar factors also influence the pattern of power generation. For instance, the efficiency of natural gas-fired power plants varies depending on the generation technology and load-serving needs, which in turn, may be affected by governmental policies of the power sector. Kahrl et al.[36] note that subsidies have historically kept coal-fired power much cheaper than natural gas for baseload generation. While natural gas increasingly fuels baseload power, it also powers peaking plants. For instance, the average heat rate of a gas turbine natural gas plant in the United States in 2015 was 11 302 BTU/kWh (30.2%, HHV), while the average heat rate of a combined cycle natural gas plant of 7655 BTU/kWh (44.6%, HHV).[39] Cycle units operating with low power plant efficiencies but fast ramp up times, are commonly



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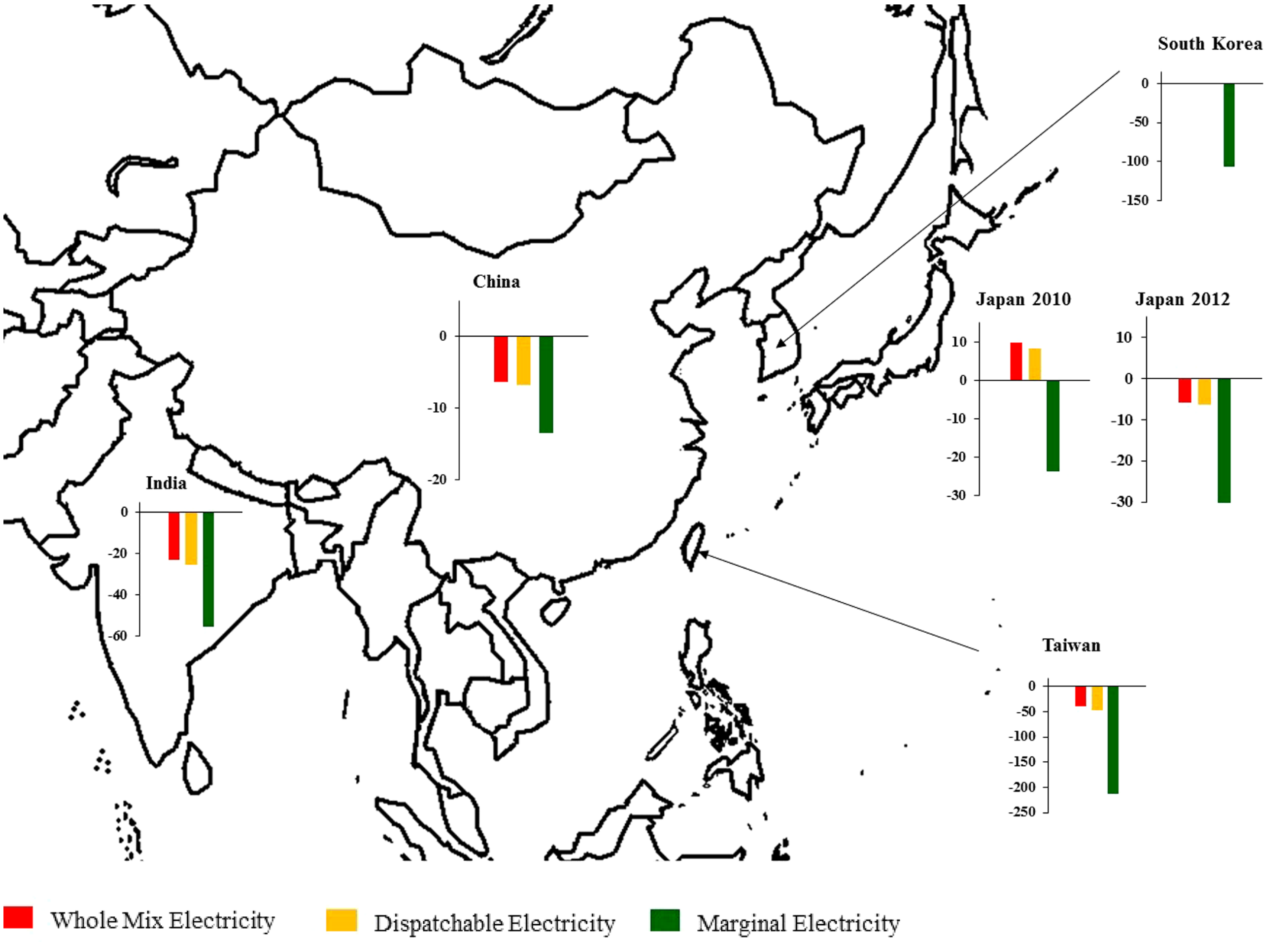


**Figure 5.** Effect of emissions displacement assumptions on life cycle results for countries importing Canadian natural gas for use in electricity generation. The *y*-axis represents the change in greenhouse gas emissions ($kgCO_2$ e/MWh).

used as peaker plants to meet large spikes in demand due to fast ramping capabilities. Combined cycle plants have higher efficiencies and are more attractive options for meeting baseload generation for following the load.[40] This, in conjunction with the availability of only point-estimates for country-level generation efficiency, points to a need to better investigate the effects of these factors on life cycle greenhouse gas emissions estimates.

Finally, our results confirm the need for standardization across life cycle assessments of natural gas-fired electricity generation, specifically highlighting the need to improve Canadian data sets (see SI for more detail). Results include two Canadian studies, both of which report total life cycle greenhouse gas emissions notably lower than those reported by the others, ranking the lowest and second lowest values in the collected data. Canadian data are presently reported with four broad categories presented, namely well drilling and completions, upstream/gathering, processing, and transmission; whereas U.S. data are reported with six broad categories, namely natural gas processing, natural gas transmission, underground natural gas storage, natural gas distribution, LNG import/export and LNG storage. Each of the six U.S. categories is further disaggregated by facility type. The Canadian data sets would benefit from disaggregating emissions, such that areas in need of research and improvement can be identified. Creating smaller, more specific processes and activities would allow more direct comparisons to be made among Canadian studies, and against U.S. studies via harmonization efforts. Through the use of disaggregate data, areas for cost-effective emissions controls may be more easily identified for producing nations.

**Emissions Displacement Scenarios.** Previous studies have typically focused on the displacement of coal, natural gas, or a cross-section of the existing electricity mix;[17,25,38] however, the displacement of electricity generation in the importing countries is uncertain. As such, we explore the following scenarios: (1) total electricity mix cross-section, (2) dispatchable electricity, and (3) marginal electricity. The amount of LNG export expected from Canada is large compared to the market of many countries (see SI). For reasons discussed in the Materials and Methods, the focus of our scenario analysis is on five countries identified in the Asia–Pacific region: China, India, Japan, South Korea, and Taiwan.

The electricity generation mix of each country is a crucial input for our emissions displacement scenarios (2010 electricity generation mix by country is presented in Figure 4). While identified as attractive markets for LNG, China and India are nontraditional buyers of LNG, meaning that they are less developed economies with a relatively short history of buying LNG (early- and mid-2000s).[26] China has had relatively strong economic growth with an increasing demand for energy resulting from its growing population and the increasing proportion of its population entering the middle class. While coal currently dominates the electricity generation mix in


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China, recent climate change policies and agreements point to an increasing desire to reduce emissions.[41] It is thus expected that the heavy dependence on coal for its electricity generation will change and move toward lower carbon sources of energy such as natural gas. Energy markets in India are also expected to grow, with natural gas consumption already having risen by 25% between 2008 and 2013. During this period, LNG imports grew by 65%.[29] Ongoing and proposed projects will increase the LNG regasification capacity in India.[29] Sixty-eight percent of electricity generation in India comes from coal whereas gas only accounts for 12%.[42]

Japan, South Korea, and Taiwan are traditional LNG buyers, being developed economies with strong financial capacities and a long history of importing LNG.[26] Post-Fukushima Japan displayed increasing demand for fossil fuel electricity with natural gas being one of the potential fuels. Natural gas consumption in Japan grew by 25% between 2008 and 2013 and was expected to grow by 0.1% per year through 2035. Japan's natural gas demand is satisfied mainly by LNG imports; it is the world's largest LNG importer, accounting for 37% of LNG trade in 2013.[29] The share of natural gas in the electricity generation mix of Japan rose from 28% in 2010 to 48% in 2012,[43,44] following the Fukushima nuclear disaster of March 2011, and the government's decision to shut down Japan's nuclear reactors. LNG demand forecast, however, has become less clear given uncertainties in fuel consumption by the power sector and government plans to restart Japan's nuclear reactors.[26] South Korea is the second largest LNG importer worldwide with 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.[29] Changes in Korea's energy policy imply an increasing use of LNG for power generation and less reliance on nuclear power. Natural gas demand in South Korea is expected to increase by almost 2% per year through 2035.[26] Taiwan is another potential market for Canadian LNG. Natural gas consumption increased by 41% between 2008 and 2013, driven by the power sector. Taiwan accounted for 5% of world's LNG imports in 2013.[29] Coal is the largest source of electricity generation (50%) in Taiwan, followed by natural gas (25%).[45] A supply/demand balance gap of about 6−8 MMTPA may be opened by 2020 and beyond[28] as a result of growing natural gas demand, expiring contracts and unreliability of current suppliers (Indonesia and Malaysia).

We present the relative effect on emissions per kWh of electricity generated in each country due to displacement of total electricity mix, dispatchable electricity, and marginal electricity in Figure 5, while Table 2 shows the expected change in GHG emissions in both gCO2e/kWh and Mton/yr in each country, resulting from the displacement of whole mix, dispatchable and marginal electricity.

With the exception of South Korea, net environmental benefits range from a reduction in life cycle GHG emissions of 5.9 $kgCO_2$ e/MWh or 6.5 megatonne (Mt) $CO_2$ e/yr in Japan, to a net reduction of 40.6 $kgCO_2$ e/MWh or 9.9 Mt $CO_2$ e/yr in Taiwan, when whole mix electricity generation is displaced in the importing countries. The higher environmental benefit observed in exporting to India, compared to China, is due to the fact that a higher percentage of the India's electricity generation is displaced relative to that of China.

The net effect of displacing electricity in Japan is very different if its electricity mix is assessed after the 2011 Fukushima nuclear disaster. Before the disaster, 26% of Japan's electricity came from nuclear power, after the disaster, the share of electricity from nuclear power was quickly reduced to less than 2% due to the shut-down of the nuclear power plants. The resultant void was filled by almost doubling the quantity of electricity generated from natural gas and oil. With oil having the larger percentage increase in the mix (increasing by 82%), it appears to be the marginal source of electricity for Japan, and is used as the marginal source in our analysis. Displacing whole mix and dispatchable electricity generation before the Fukushima disaster would result in a net increase in the life cycle GHG emissions of 9.9 and 8.3 $kgCO_2$ e/MWh, corresponding to an increase of 10.9 and 9.2 Mt $CO_2$ e/yr, respectively. However, after the Fukushima nuclear disaster, due to the significant change in the electricity generation mix of Japan, displacing whole mix and dispatchable electricity generation would result in a net decrease in the life cycle emissions of 5.9 and 6.4 $kgCO_2$ e/MWh, corresponding to a decrease of 6.5 and 7.0 Mt $CO_2$ e/yr, respectively. Thus, the overall results can be driven by unanticipated events in the energy sector.

**Table 2. Change in GHG Emissions in Selected Countries Resulting from the Displacement of Whole Mix, Dispatchable and Marginal Electricity**

| | whole mix electricity displacement | | dispatchable electricity displacement | | marginal electricity displacement | |
|---|---|---|---|---|---|---|
| | $gCO_2e$/kWh | Mton/yr | $gCO_2e$/kWh | Mton/yr | $gCO_2e$/kWh | Mton/yr |
| China | −6.4 | −24.9 | −6.7 | −26.3 | −13.5 | −52.6 |
| India | −22.8 | −20.6 | −25.3 | −22.9 | −55.6 | −50.2 |
| Japan 2010 | 9.9 | 10.9 | 8.3 | 9.2 | −23.7 | −26.3 |
| Japan 2012 | −5.9 | −6.5 | −6.4 | −7.0 | −30.5 | −33.4 |
| South Korea | −0.1 | 0.05 | −1.0 | −0.5 | −105.9 | −52.6 |
| Taiwan | −40.6 | −9.9 | −46.8 | −11.4 | −213.5 | −52.1 |

Overall, our results suggest that there is a net environmental benefit in terms of greenhouse gas emissions reduction when importing Canadian natural gas for electricity generation in the five countries considered, except for the case of Japan prior to the Fukushima nuclear disaster. However, the magnitude of the GHG reduction depends on the type of electricity that is displaced. In reality, a mix of sources will comprise the marginal electricity displaced by LNG imports including older power sources that can be retired earlier than would otherwise be possible and newer sources that will not be built because LNG imports make them unnecessary. The most abundant fuel source may be a good proxy for the older sources that may go offline with new imports, but it is much harder to determine what new sources would have been built in the absence of new LNG imports. Due to the plummeting costs of renewable power, it may increasingly be able to compete economically with gas-powered electricity generation in non-OECD Asian countries.[3] In this scenario, LNG imports would result in increased greenhouse gas emissions in importing countries. In our assessment, we examine a plausible estimate of the volume of LNG that could be exported from Canada with present proposals/offtake agreements. Several of the importing countries have relatively small market sizes, rendering them less useful as examples using our approach. Korea, for instance, would have to expand its renewable power by 1800% to generate the same amount of electricity that could be generated


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from our assumed Canadian LNG export capacity. Of course, smaller volumes of Canadian LNG may displace renewable power that might have otherwise been built in importing countries. To address the scenario of LNG trade displacing of renewable capacity additions, a comparison of life cycle GHG emissions estimates for renewable energy are compared to those from fossil energy in the SI.

## 4. CONCLUSIONS

As the world begins to transition to a lower carbon economy, new regulations and policies are being developed to move away from carbon-intensive sources such as coal, to less carbon-intensive sources, such as natural gas. Such changes rely not only upon policy, regulation, and political will, but also economics. The increasing global demand and supply of natural gas has led to the emergence of three different markets in North America, Europe and the Asia−Pacific regions, with prices in the Asia−Pacific region having been the highest to date. Examining the influence of certain factors such as country level fleet efficiencies shows the carbon intensities, and climate implications resulting from the use of BC LNG in electricity generation by import countries are significantly sensitive to country level parameters. When country level factors were applied to the base set of data, median life cycle emissions of LNG imports ranged from 568 $gCO_2$ e/kWh (Taiwan) to 872 $gCO_2$ e/kWh (India). Estimates of median life cycle emissions arising from BC LNG exports were 562 $gCO_2$ e/kWh and 666 $gCO_2$ e/kWh, when power plant efficiencies of 55% HHV and 46.4% HHV were applied, respectively. The potential economic and environmental benefits have made the justification for exporting natural gas from Canada to the Asia-pacific region compelling, with China, India, Japan, South Korea, and Taiwan being the most likely destinations.

Certainly, future research should include improving data (e.g., more detailed power-plant efficiency data sets by country) and measurements (e.g., better characterization of methane emissions). We have conducted a first-order assessment of emissions displacement to inform future research, where we note that country-level power plant data were limited. While our electricity displacement scenarios do not include country-level power plant efficiencies, the mean estimates for displacement in each country will not be representative of actual capacity additions and retirements. More sophisticated data sets detailing plant-level data for each country would enable analysts to model capacity additions and retirements on actual decision-making (e.g., retiring the least efficient, highest polluting coal plants). Future research could focus specifically on full power-plant data sets for countries, to better determine how specific factors such as individual plant retirements may influence results. Our results highlight the importance of assumptions regarding country-level emissions displacement, but our analysis captures only first-order impacts. A more comprehensive research effort that combines a macro-economic model and dispatch model could determine more robust country-specific displacement factors to guide LNG investment decisions. Overall, Canadian LCA data sets would benefit from disaggregating emissions. Creating smaller, more specific processes and activities would allow more direct comparisons to be made among Canadian studies, and against U.S. studies via harmonization efforts. Additionally, the LCAs seldom provide adequate explanations regarding the underlying assumptions of the estimated emissions. As Heath et al.[23] demonstrated, emissions estimations tend to depend on a variety of assumptions made by authors. Future work on Canadian natural gas would benefit significantly from detailed documentation of the underlying assumptions of data sets, in consideration of the factors and processes examined by Heath et al.[23] More specific to measurement, data were not available to quantify the influence of natural gas distribution on the results; we note the need for additional research to characterize better these emissions. More knowledge also allows analysts to determine where emissions reductions may be viable, cost-effective or even profitable.

While these results are specific to Canada, they provide insight into economic opportunities and the overall climate implications of LNG export for other nations. Canada, as well as other countries, may experience LNG market challenges heading into the future. Countries like United States and Australia, with increasing natural gas production and advanced LNG export infrastructure, have an obvious advantage over countries like Canada where there is relatively little or no LNG export infrastructure in place.[3] While costs serve as a barrier for growth in LNG trade, multilateral agreements serve to support trade and economic growth. For example, the recently proposed Trans-Pacific Partnership would have served to increase trade and enhance economic development with 12 countries through decreasing tariff and nontariff barriers.[46] Though the Partnership lists environment as a priority, action on climate remains ambiguous or left to the participating nations, as is the case with existing trade agreements.[47] This highlights the role of domestic policies in mitigating power and natural gas sector emissions, and international agreements in meeting global climate goals. Domestic factors such as fleet efficiency of generation plants, T&D losses and transition to low carbon fuel have been found to be particularly important to achieve the desired goals of reducing country-level greenhouse gas emissions. With the increasing number of nations participating in LNG markets, the overall climate impact of expanding LNG export rests on the effectiveness of these mechanisms, all of which have a challenging political history.

## ■ ASSOCIATED CONTENT

### Supporting Information

The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.7b05298.

Additional information on methods, detailed calculations, and supplementary results is included (PDF)

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The manuscript was written through contributions of all authors. All authors have given approval to the final version of the manuscript.

### Notes

The authors declare no competing financial interest.

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