4.4.3 INTRODUCTION

Environment and Climate Change Canada (ECCC) advised WesPac Midstream–Vancouver LLC (WesPac) that for the purposes of the Environmental Assessment, an upstream greenhouse gas (GHG) assessment is required for the WesPac Tilbury Marine Jetty Project (the Project) (ECCC, 2016). The upstream GHG assessment was undertaken in consideration of ECCC’s draft methodology for the assessment of upstream GHG emissions posted in the Canada Gazette on March 19, 2016 (Government of Canada, 2016a), and additional guidance on the required content of the assessment provided by ECCC on May 18, 2018 (ECCC, 2018b). As defined by ECCC in the draft methodology, upstream GHG emissions include all industrial activities from the point of resource extraction to the Project under review. The specific processes included as upstream activities will vary by resource and project type, but in general they include extraction, processing, handling, and transportation. The assessment of the upstream emissions is separated into two parts consistent with the ECCC guidance. Part A is a quantitative estimate of the GHG emissions released upstream of the Project, and requires the following (ECCC, 2018b):

- Estimate the upstream GHG emissions during the operational lifetime of the proposed Project, on an annual basis.
- Estimate the upstream GHG emissions based on the maximum additional capacity that the Project would allow.
- Estimate the upstream GHG emissions for all processes upstream of the proposed Project, including production, processing, and transport of the Project’s natural gas supply.
- Estimate the upstream GHG using verifiable emission intensities that are recent and pertinent to the region and provide a rationale for selecting those emission intensities.
- Aggregate the GHG emissions from carbon dioxide (CO2), methane (CH4), and nitrous oxide (N2O) to CO2 equivalent (CO2e) units per year.
- State and justify all assumptions for the estimate.

Part B discusses the conditions under which the Canadian GHG upstream emissions estimated in Part A could be expected to occur even if the Project were not built. Conducting Part B of the upstream GHG assessment requires the following elements in the discussion (ECCC, 2018b):

- Discussion of domestic and international policy environments;
- Discussion of technical and economic information to assess upstream production through energy market analysis;
- Estimation of impacts on Canadian and global GHG emissions;
- Estimation of how incremental production and transport may impact GHG emissions; and
- Development of Project and No Project cases.
The Project does not represent a new source of demand for upstream production. Rather, it represents an alteration of transportation method for existing liquefied natural gas (LNG) production that will alter GHG emissions (WesPac, 2018 pers. comm.). The FortisBC Tilbury LNG Liquefaction Plant (Tilbury LNG Plant) is currently undergoing an expansion project to meet the projected long-term growth for LNG as a fuel source (FortisBC, 2018a, 2018b). The project is near completion (FortisBC, 2018a) and in the process of obtaining permits to operate (Metro Vancouver, 2018). Therefore, the full build-out capacity (3.5 million tonnes per year) of the Tilbury LNG Plant is expected to occur regardless of the Project, with the Project only impacting how the LNG will be shipped to the end users. Incremental GHGs are likely to be caused by the change from truck transport (local and national) and International Organization for Standardization (ISO) container transport of LNG currently occurring from the Tilbury LNG Plant in the absence of the Project (FortisBC, 2018a), to a blend of bunker vessel and carrier transport (international), as a result of the Project. It is assumed that LNG from the Tilbury LNG Plant or the Project would be shipped to Asia, as this region is currently the largest consumer of LNG and still shows signs of growth (see discussion in Section 4.4.2 and subsections). As there are uncertainties in the future demand for LNG, the current conditions of largest consumer demand in Asia is held constant throughout the analysis for conservatism, as this represents the largest shipping distance.

CEAA 2012 Sections 5(1)(c)(i) and 5(2)(b)(i) are relevant to Upstream GHG Assessment as changes potentially affecting upstream GHGs and air quality are linked to the health and socio-economic conditions of Aboriginal peoples and to public stakeholders. This includes potential project-related changes in air quality—including pollutants and greenhouse gasses—which have the potential to impact the air local people breathe and affect their health.

### 4.4.3.1 Description of Project Throughput and Shipping Estimates

WesPac proposes to construct and operate a marine jetty for loading LNG onto LNG carriers and LNG bunker vessels at Tilbury located along the South Arm of the Fraser River, in Delta, British Columbia (BC). The Project site is situated adjacent to the existing Tilbury LNG Plant.

The purpose of the Project is to transfer LNG to carriers and bunker vessels for delivery to both offshore export markets and local fuel markets. The marine jetty will accommodate one vessel loading at a time, either LNG carriers up to 100,000 m³ of LNG capacity that would serve offshore export markets or individual LNG bunker vessels up to 7,500 m³ of LNG capacity that would serve regional markets. The proposed Project operation duration is a minimum of 30 years from 2023 to 2053. The Project annual LNG throughput of 3,500,000 tonnes is used to perform the quantitative estimate of upstream GHG emissions in Part A, and to inform the assessment of the impact on Canadian and global GHG emissions in Part B.

### 4.4.3.2 Part A: Quantitative Estimation of Upstream Greenhouse Gas Emissions

#### 4.4.3.2.1 Background

The following sections in Part A present estimates for a range of upstream GHG emissions associated with the extraction, processing, handling, and transportation of natural gas and production of LNG upstream of the Project site. The methodology used to estimate the upstream emissions is discussed in Section 3.2. The resulting GHG emission estimates are compared and discussed in Section 3.3. Following Part A, Part B (Section 4.0) provides a
discussion of the estimated emissions on the Canadian and global GHG emissions, including the degree to which the Project could enable additional LNG production and incremental emissions.

### 4.4.3.2.2 Methods

For the purposes of this assessment, upstream is defined as all natural gas sector stages before the Project, namely, natural gas production, processing, pipeline transmission, and LNG production. The upstream GHG emissions include fugitive emissions, venting, flaring, combustion, and other sources. The Project site is located adjacent to the existing Tilbury LNG Plant, which produces and stores LNG. The Project will take custody of the LNG from the Tilbury LNG storage tank, and a vapour return pipe will carry boil-off gas back to the Tilbury LNG Plant boil-off gas compressor. The Tilbury LNG Plant has an existing natural gas supply pipeline, so no major pipeline construction is expected. In addition, given the relatively small gas volumes for LNG production, it is unlikely that any additional major transmission infrastructure is needed. The GHG emissions from the LNG production process in the Tilbury LNG Plant need to be included in addition to the GHG emissions from natural gas production, processing, and transmission to account for the complete upstream GHG emissions of the Project.

The GHG emissions in the forms of carbon dioxide (CO₂), methane (CH₄) and nitrous oxide (N₂O) were integrated to obtain GHG emissions in carbon dioxide equivalent (CO₂e) by considering their respective global warming potentials (GWPs). The GWPs in the Canada’s National Inventory Report 1990–2016 (Table 4.4.3-1) were used in this assessment (ECCC, 2018c).

<table>
<thead>
<tr>
<th>GHG</th>
<th>100-year GWP</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂</td>
<td>1</td>
</tr>
<tr>
<td>CH₄</td>
<td>25</td>
</tr>
<tr>
<td>N₂O</td>
<td>298</td>
</tr>
</tbody>
</table>

Source: (ECCC, 2018c).

GHG = greenhouse gas; CO₂ = carbon dioxide; CH₄ = methane; N₂O = nitrous oxide; GWP = Global Warming Potential.

To quantify the total upstream GHG emissions, three different approaches were used. The first approach used data from the ECCC GHG forecast (ECCC, 2018a). The second approach used data from the BC Shale Scenario Tool (Kniëwasser and Horene, 2015), and the third approach used data from the BC LNG life cycle analysis (Globe Advisors, 2014).

- **Approach 1: ECCC GHG forecast** (ECCC, 2018a)—This approach applied ECCC-provided emission factors associated with upstream GHG emissions from natural gas production, processing, and transmission in the Alberta and BC to estimate the annual upstream GHG emissions up to the year 3030. In the absence of emissions data on LNG production the Tilbury LNG Plant an emission factor of 0.177 t CO₂e/t LNG was used.
Approach 2: BC Shale Scenario Tool (Kniewasser and Horene, 2015)—This tool was developed to better understand environmental impacts caused by development of LNG terminals along BC’s coast. It allows users to explore the potential implications with different levels of LNG and shale gas development, different source basins for the gas, and different technologies and practices.

Approach 3: The BC LNG GHG life cycle analysis study (Globe Advisors, 2014)—This study used the GHGenius model to estimate GHG emissions, which makes assumptions about the natural gas supply mix similar to those used in the BC Shale Scenario Tool.

Each of the approaches relies on a unique GHG emission factor to quantify the total upstream GHG emissions. These emission factors are described in Sections 3.2.1 and 3.2.2, and the results of the three different approaches to quantify the total upstream GHG emissions are presented in Section 3.3.

4.4.3.2.2.1 Liquefied Natural Gas Production Greenhouse Gas Emission Factors

The GHG emissions for LNG production are a function of the energy used for liquefaction and fugitive emissions from storage and transfers of product. In 2017, a lifecycle analysis of the GHG emissions for the Tilbury LNG Plant was undertaken using GHGenius model Version 4.03a ((S&T)2 Consultants Inc., 2017). The modelled LNG production emission factor is 3,449 grams of carbon dioxide equivalent per gigajoule of natural gas (g CO₂e/GJ). The emission factor can be converted to 0.177 tonnes of CO₂e per tonne of LNG produced (0.177 t CO₂e/ t LNG) assuming a natural gas heating value of 0.0373 Gigajoules per cubic metre (GJ/m³) and equivalence of 1 m³ natural gas to 7.2487 × 10⁻⁴ t of LNG (NEB, 2018). The BC Shale Scenario Tool (Kniewasser and Horene, 2015) and the BC LNG GHG life cycle analysis (Globe Advisors, 2014) also provide emission factors for LNG production. The LNG production emission factors from these three sources are listed in Table 4.4.3-2. The emission factor from the BC LNG life cycle analysis was for a “clean” LNG plant that utilizes renewable electricity without carbon capture and storage (CCS) technology.

Table 4.4.3-2: Greenhouse Gas Emission Intensities of Liquefied Natural Gas Production

<table>
<thead>
<tr>
<th>Source</th>
<th>GHG Emission Factor (t CO₂e/t LNG)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tilbury LNG Plant GHG emission life cycle analysis(a)</td>
<td>0.177</td>
</tr>
<tr>
<td>The BC Shale Scenario Tool(b)</td>
<td>0.160</td>
</tr>
<tr>
<td>The BC LNG GHG life cycle analysis(c)</td>
<td>0.270</td>
</tr>
</tbody>
</table>

(a) Source : (S&T)2 Consultants Inc., 2017.
(b) Source: Kniewasser and Horene, 2015.
(c) Source: Globe Advisors, 2014.

GHG = greenhouse gas; t CO₂e/t LNG = tonne of carbon dioxide equivalent per tonne of liquified natural gas; LNG = liquified natural gas.
4.4.3.2.2.2 Upstream Greenhouse Gas Emissions Approaches

The GHG emissions upstream of the Project related to natural gas production, processing, and transportation were quantified using three different approaches, as described in the following sections.

4.4.3.2.2.2.1 Approach 1: Environment and Climate Change Canada Greenhouse Gas Forecast

In Canada’s 7th National Communication and 3rd Biennial Report (ECCC, 2017), ECCC presents projections of GHG emissions through 2030. ECCC has provided emission intensities used to estimate the GHG emissions from natural gas production, processing, and transmission in Alberta and BC. Two cases were considered using the ECCC emission factors:

- The natural gas to the Tilbury LNG Plant is supplied from BC natural gas production and processing.
- The natural gas supply is a mixture of 75% BC gas supply and 25% Alberta gas supply.

The two ECCC emission forecast cases use average emission factors applicable for each province for each of the upstream stages—natural gas production, processing, and pipeline transmission sub-sectors—and these emission factors were used to calculate the upstream emissions for this assessment. Forecasts are available year by year up to 2030 and are therefore not available for the entire 30-year expected lifetime of the Project. Table 4.4.3-3 provides the emission factors for years 2020, 2025, and 2030. The emission factor of LNG production from the Tilbury LNG Plant GHG lifecycle analysis (0.177 t CO₂e/t LNG) was used in combination with the ECCC GHG forecast to generate total upstream GHG emissions for this approach. For the Project operation years beyond 2030, the 2030 GHG emission factors were applied.

Table 4.4.3-3: Environment and Climate Change Canada Upstream Greenhouse Gas Emission Factors (t CO₂e/t LNG)

<table>
<thead>
<tr>
<th>Sector</th>
<th>2020 AB</th>
<th>2020 BC</th>
<th>2025 AB</th>
<th>2025 BC</th>
<th>2030 AB</th>
<th>2030 BC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas production</td>
<td>0.264</td>
<td>0.151</td>
<td>0.196</td>
<td>0.130</td>
<td>0.195</td>
<td>0.127</td>
</tr>
<tr>
<td>Natural gas processing</td>
<td>0.267</td>
<td>0.164</td>
<td>0.267</td>
<td>0.154</td>
<td>0.267</td>
<td>0.147</td>
</tr>
<tr>
<td>Natural gas transmission</td>
<td>0.049</td>
<td>0.040</td>
<td>0.050</td>
<td>0.035</td>
<td>0.049</td>
<td>0.031</td>
</tr>
<tr>
<td>LNG production</td>
<td></td>
<td></td>
<td>0.177</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Upstream⁽ᵃ⁾</td>
<td>0.758</td>
<td>0.532</td>
<td>0.690</td>
<td>0.496</td>
<td>0.688</td>
<td>0.483</td>
</tr>
</tbody>
</table>

⁽ᵃ⁾ Total numbers do not add up due to rounding

AB = Alberta; BC = British Columbia; LNG = liquified natural gas.
4.4.3.2.2.2 Approach 2: The BC Shale Scenario Tool

The BC Shale Scenario Tool uses a global warming potential of 21 for CH₄, whereas the ECCC GHG Forecast uses a global warming potential of 25. The Pembina tool predicted GHG emissions were re-calculated with a GWP of 25 for CH₄. The Pembina Shale Tool was run for two scenarios:

- with the Project LNG throughput not included, to calculate upstream GHG emissions associated with non-LNG natural gas development; and
- with both the Project LNG throughput and the demand of non-LNG natural gas development.

The difference between these two scenarios is the predicted measure of GHG emissions attributable to the Project. The Pembina Shale Tool is utilized assuming that the non-LNG natural gas demand remains constant at 2014 levels (default of the tool) and the default source of gas (i.e. a 65%, 20%, and 15% Montney basin, Horn River basin, and conventional natural gas supply mix in 2030). The LNG production emission factor (0.16 t CO₂e/t LNG) was included in the tool to estimate the complete upstream GHG emissions associated with natural gas extraction, processing, and transportation and LNG production. The BC Shale Tool forecasts GHG emissions by year 2050. For the Project operation years beyond 2050, the emissions of year 2050 were assumed.

4.4.3.2.2.3 Approach 3: The BC Liquefied Natural Gas Greenhouse Gas Life Cycle Analysis

In early 2014, Globe Advisors conducted a LNG GHG life cycle analysis for the BC Ministry of Environment Climate Action Secretariat (Globe Advisors, 2014). The study aimed to understand the impact of BC liquefaction plants on global GHG emissions. It used the GHGenius model to estimate GHG emissions, which makes assumptions about the natural supply mix similar to those used in the BC Shale Scenario Tool. Emission factors for the “clean” LNG plant scenario without CCS are listed in Table 4.4.3-4.

<table>
<thead>
<tr>
<th>Process</th>
<th>GHG Emission Factors (t CO₂e/t LNG)(a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel distribution and storage</td>
<td>0.06</td>
</tr>
<tr>
<td>Fuel production</td>
<td>0.06</td>
</tr>
<tr>
<td>Feedstock recovery</td>
<td>0.08</td>
</tr>
<tr>
<td>Gas leaks and flares</td>
<td>0.04</td>
</tr>
<tr>
<td>LNG production</td>
<td>0.27</td>
</tr>
<tr>
<td><strong>Total Upstream</strong></td>
<td><strong>0.50</strong></td>
</tr>
</tbody>
</table>

(a) Total numbers do not add up due to rounding
GHG = greenhouse gas; t CO₂e/t LNG = tonne of carbon dioxide equivalent per tonne of liquefied natural gas; CO₂ = carbon dioxide; H₂S = hydrogen sulfide; LNG = liquefied natural gas
4.4.3.2.3 Results – Estimated Upstream Emissions

Table 4.4.3-5 summarizes upstream emissions estimates for the Project from the three approaches assuming LNG production of 3.5 million tonnes per year.

**Table 4.4.3-5: Upstream Emission Estimates**

<table>
<thead>
<tr>
<th>Year</th>
<th>GHG Emissions (kt CO₂e)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Approach 1</td>
</tr>
<tr>
<td></td>
<td>ECCG GHG Forecast: 100% BC</td>
</tr>
<tr>
<td>2023</td>
<td>1,755.5</td>
</tr>
<tr>
<td>2024</td>
<td>1,744.2</td>
</tr>
<tr>
<td>2025</td>
<td>1,734.7</td>
</tr>
<tr>
<td>2026</td>
<td>1,723.4</td>
</tr>
<tr>
<td>2027</td>
<td>1,709.3</td>
</tr>
<tr>
<td>2028</td>
<td>1,701.7</td>
</tr>
<tr>
<td>2029</td>
<td>1,696.6</td>
</tr>
<tr>
<td>2030</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2031</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2032</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2033</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2034</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2035</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2036</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2037</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2038</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2039</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2040</td>
<td>1,689.3</td>
</tr>
</tbody>
</table>
### Section 4.4.3: Upstream GHG Assessment

<table>
<thead>
<tr>
<th>Year</th>
<th>GHG Emissions (kt CO₂e)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Approach 1</td>
</tr>
<tr>
<td></td>
<td>kt CO₂e = kilotonnes of carbon dioxide equivalent; ECCC = Environment and Climate Change Canada; GHG = greenhouse gas; LNG = liquefied natural gas; BC = British Columbia; AB = Alberta.</td>
</tr>
<tr>
<td>2041</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2042</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2043</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2044</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2045</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2046</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2047</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2048</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2049</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2050</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2051</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2052</td>
<td>1,689.3</td>
</tr>
<tr>
<td>2053</td>
<td>1,689.3</td>
</tr>
</tbody>
</table>

Using Approach 1 with 100% BC gas supply, the upstream GHG emissions from the Project were estimated to be 1,755.5 kilotonnes of carbon dioxide equivalent (kt CO₂e) in 2023, decreasing to 1,689.3 kt CO₂e in 2053. For the 75% BC / 25% AB gas supply scenario, the approach estimates higher upstream emissions from the Project, at 1,922.0 kt CO₂e in 2023, decreasing to 1,869.0 kt CO₂e in 2053.

Approach 2 estimates upstream GHG emissions to be 2,163.8 kt CO₂e in 2023 and 2413.9 kt CO₂e in 2053. Unlike Approach 1, the BC Shale Scenario Tool forecasts increasing upstream GHG emissions from 2030 to 2047 due to the changes of gas supply from conventional gas supply, Horn River basin, and Montney basin (i.e., 15% of Horn River basin in 2025 and 20% in 2030 and beyond) in the model. The formation CO₂ of the Horn River basin
is 218.78 tonne CO₂ per million cubic metres (t CO₂/million m³) of natural gas processed, which is much higher than those of Montney basin (0 t CO₂/million m³) and conventional natural gas (54.01 t CO₂/million m³).

The GHGenius model used in the BC LNG GHG life cycle analysis does not include emission projections. Thus, no year-to-year data are available and only one single upstream GHG emission was estimated. This third approach estimates emissions of 1,750.0 kt CO₂e, which are comparable to the emission estimates from Approach 1 with 100% BC natural gas production and processing.

In summary, the total upstream GHG emissions for the projects were estimated to range from 1,750.0 kt CO₂e to 2,163.8 kt CO₂e in 2023 and from 1,689.3 kt CO₂e to 2,413.9 kt CO₂e in 2053. These are considered conservative estimates given new technologies and regulations (e.g., methane regulations) are likely to reduce upstream emissions in the future.

4.4.3.3 Part B: Impact on Canadian Upstream and Global Greenhouse Gas Emissions

4.4.3.3.1 Background

Part A presents estimates of GHG emissions upstream of the Project adjacent to the existing Tilbury LNG Plant. However, it is important to consider the degree to which the Project could enable additional upstream emissions and incremental emissions, including the elements as described in Section 1.0.

The following sections within Part B assess the degree to which natural gas production (and the subsequent LNG produced that would be transported from the Project) could occur in the absence of the Project. The Project is not expected to alter the production of LNG from the Tilbury LNG Plant because the Project does not represent a new source of demand for upstream production. Rather, it represents an alteration of transportation method for existing LNG production that will alter GHG emissions (WesPac, 2018 pers. comm.), as the current expansion project is near completion (FortisBC, 2018a) and in the permitting stage (Metro Vancouver, 2018). Therefore, the incremental change in Project upstream GHG emission levels is equivalent to the opportunity cost of transport between the Project Case and No Project Case measured in CO₂e. The No Project Case is selected to represent the current transportation of the Tilbury LNG Plant, which is a mixture of truck transport for local and national end users, and ISO containers for sea transportation. The Project Case is selected to represent the shipment of all LNG to international markets using a mixture of barges and carriers. Global emissions are considered since the nature of incremental changes in emission levels are likely to occur due to international displacement and transport.

4.4.3.3.2 Methods

Part B (Section 4.0) places the Project within the context of the Pacific LNG trade and transport environment. The analysis estimates projected change in GHGs with construction of the Tilbury Marine Jetty Project, taking into consideration the location of the consumption endpoint for the LNG from the Tilbury LNG Plant.

The following outlines the assessment method for Part B:

- Section 4.3 describes regulatory frameworks and climate change commitments which frame the national and international targets relevant to GHG emissions.
Section 4.4 lays out the domestic and international natural gas outlook to provide production and demand projections. With regard to the Project's capacity and WesPac’s current outlook to ship domestically and internationally, the Canadian, American, and Asia Pacific markets are considered. Australian LNG will be considered briefly as a competitor for Canadian LNG in Asia Pacific.

Section 4.5 frames the alternatives considered for transport from the Tilbury LNG Plant including the Project. This section also contains an assessment of the projected GHG emissions from each transportation alternative including a sensitivity analysis.

Section 4.6 evaluates the transportation alternatives considered. This section will highlight primarily the expected changes in GHG emissions from the projections in Section 4.5 but will also note additional GHG considerations beyond the scope of the alternative considerations model 1.

4.4.3.3 Emissions Projections and Climate Change Commitments

The emissions projections and climate change commitments on a national and international scale shape the viability of these markets as destinations for LNG from the Tilbury LNG Plant via the proposed Tilbury Marine Jetty. This section considers the emissions reduction targets and climate change commitments of key actors in the Pacific LNG trade, including Canada. The US and Asia Pacific are described in this section as they represent key market actors in the Pacific LNG trade with differing situations.

4.4.3.3.1 Canada

As described in Canada’s Greenhouse Gas Emissions Reference Case from 2016, Canada’s annual GHG emissions are forecasted to increase 10 megatonnes (Mt) from 732 Mt in 2014 to 742 Mt in 2030 if no additional action is taken (Government of Canada, 2016b). The reference case does not consider the impacts of broader strategies or future measures within existing plans where significant details are not finalized (Government of Canada, 2016b). LNG is not expected to be a large contributor to emissions increases as emissions from LNG are anticipated to increase 3 Mt between 2005 and 2030 (Government of Canada, 2016b). Emissions related to transportation are anticipated to decline 14 Mt between 2005 and 2030 (Government of Canada, 2016b).

The National Energy Board (NEB) provides a range for fossil fuel use where the high projection, the High Carbon Price Case, is 8% higher than the Reference Case while the low projection, the Technology Case, is 5% lower than the Reference Case (NEB, 2017a). The NEB identifies the technological and regulatory environment as key factors in determining Canada’s emissions future (NEB, 2017a). This is illustrated by the variance in the three NEB 2017 cases (Reference Case, High Carbon Price Case, and Technology Case). Technological and regulatory change are the primary drivers behind the composition of Canada’s energy system and, as result, Canada’s emissions output. In addition, the NEB notes projections are influenced by the world market and regulatory environment (NEB, 2017a). The complex market forces related to national and company level choices shaping the energy market composition are intertwined with the choices of other national and company level energy market

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1 The model describes the case assessment in Section 4.5 which projects changes in GHG emission levels over the Project operational life.
actors. As a result, the regulatory frameworks in key markets will influence the upstream emissions related to Canada’s LNG activities through the global trade of LNG.

In recognizing the regulatory role in shaping climate change outcomes, the Government of Canada has provided a list of priorities related to climate change. The Government of Canada’s priorities include adherence to the Paris Agreement and other international initiatives through the United Nations, including to enhance climate adaption, promote collaborative approaches, and share knowledge (Government of Canada, 2016d). To do this, Canada committed $2.65 billion in climate finance over five years in developing countries to reduce emissions and increase resilience to climate change (Government of Canada, 2016d). The approach Canada has taken aligns with the key provisions of the Paris Agreement, which shapes international climate action including the domestic policy of most nations. As part of the Paris Agreement, Canada submitted Canada’s Mid-Century Long-Term Low Greenhouse Gas Development Strategy to the United Nations Framework Convention on Climate Change (UNFCCC) (Government of Canada, 2016c, 2016e; UNFCCC, 2018).

4.4.3.3.3.2 International

In December of 2015, 195 countries reached the Paris Agreement to combat climate change. The Agreement will strengthen the effort to limit the global average temperature increase to below 2°C with a goal of a 1.5°C increase (Government of Canada, 2016e; UNFCCC, 2018). Key actors in the Pacific LNG trade ratified the Paris Agreement, while the US has stated a desire to withdraw. Each nation has individual goals and strategies to reduce emissions as part of the Paris Agreement commitments.

4.4.3.3.3.2.1 United States

Currently, the US is the only country to reject the Paris Agreement with a stated desire to withdraw when eligible in 2020 (Meyer, 2017). This intention was announced in 2017 when the current US President was inaugurated (Meyer, 2017). At this time, the President released the America First Energy Plan shaping energy policy in the US (Vakhshouri, 2017). The plan included the expansion of coal use and domestic fossil fuel production, including natural gas (Vakhshouri, 2017). In conjunction with expanding US production, the current US administration is strongly promoting an increase in LNG exports. With its emphasis on reducing trade deficits, the administration sees sales of US LNG as an element of its trade policy. Asia is considered to be a key player in the US LNG export strategy as China is commonly a target of policies aimed at reducing the trade deficit (Vakhshouri, 2017). The US is actively working with Chinese energy buyers and expanding LNG export capabilities with the goal of exporting more LNG in the near future (Vakhshouri, 2017). Along with Australia and various Association of Southeast Asian Nations (ASEAN) countries, the US represents competition for Canadian LNG exports. Additionally, expanded production, price decreases from oversupply, and a stated preference for domestic energy sources may limit Canadian markets for LNG in North America. Additionally, the US is the largest current market for Canadian LNG exports. Therefore, changes in American policy and natural gas production are likely to impact Canada’s LNG trade.
4.4.3.3.2.2 Asia Pacific

Countries in the Asia Pacific region failed to meet the Paris Agreement goals with their nationally determined contributions (NDCs) to meet the 2°C target (Asian Development Bank, 2016). However, the goals still signal a willingness to reduce emissions in the context of national circumstances (Asian Development Bank, 2016). Regional adaption techniques as articulated in NDCs include absolute emission reductions (e.g., Bangladesh, Bhutan, Indonesia, Philippines, Tajikistan, Thailand, and Vietnam), reductions in emission intensity of growth (e.g., China, India, Laos, and Papua New Guinea), or improving forest cover (e.g., Cambodia, Laos, and Sri Lanka) (Asian Development Bank, 2016). These goals align with natural gas use as an energy source considering the high use of coal in the region.

4.4.3.3.4 Canadian and International Gas Market

Using the analysis in Section 4.3, Section 4.4 considers supply and demand forces in the LNG markets for key destinations and producers. Since viability of markets will shape the endpoint destination for LNG from the Tilbury LNG Plant, transportation of the LNG is identified as the key determinant of incremental GHGs as considered in this assessment. The distance and mode of transit will be used to shape the forecasted GHG emissions in the Project and alternative cases. A visual representation of LNG trade flows is included in Figure 5 of the International Energy Agency’s (IEA’s) 2017 Natural Gas Information: Overview (IEA, 2017b).

4.4.3.3.4.1 Canadian Market

4.4.3.3.4.1.1 Canadian Production

Canada’s LNG production faces many challenges but also has opportunity for growth. The industry as a whole is not as viable as it has been in recent years. However, project-specific economics differ from the overall economics of the industry, where certain projects may possess competitive advantages improving their feasibility and likelihood of success. Competitive advantages may include cost saving and risk reduction factors such as geographical proximity and government, non-government, and/or public support. Additionally, growth in LNG demand in the Asia Pacific region is likely to improve the position of Canada in the LNG market over the next decade.

Canada has an abundance of natural gas and produces far more natural gas than is required for domestic demand (NEB, 2017b). Traditionally, the US has been the primary export market for excess Canadian gas, but growing shale gas production in the US has reduced this demand significantly. Consequently, Canadian producers have been seeking overseas markets for their natural gas. Price differentials between North American gas and global LNG have also been large enough to justify the facility development and long-range transportation costs related to LNG trade, although these differentials have been decreasing in recent years (NEB, 2017b). Smaller price differences due to declining Asian and European gas prices may reduce the viability of the long-range transport facilities (NEB, 2017b). The smaller price differences have resulted in the cancellation of many LNG projects in Canada (NEB, 2017b).
There have been a number of LNG projects proposed on Canada’s west and east coasts. Some of these projects are moving through the study or design phases. According to the Province of BC, a reported $20 billion has been spent on the LNG industry in BC (NEB, 2017b). Despite this, Canada has yet to emerge as a significant participant in global LNG markets. There were no LNG export projects under construction in Canada as of July 2017, and only one of the smaller projects, Woodfibre LNG, has announced plans to move into the construction phase (NEB, 2017b).

In the NEB’s Canada’s Energy Future 2017 Reference Case, total LNG production was projected to rise steadily throughout the Reference Case period as natural gas producers target areas with rich natural gas deposits (NEB, 2017a). Key uncertainties in the 2017 Reference Case include the assumption that infrastructure will be built to meet demand for Canadian LNG and the volume of Canadian LNG exports (NEB, 2017a). With few LNG facilities developed in Canada, it is uncertain how market conditions for Canadian LNG will change, though Canada appears to have key competitive advantages, as described below (NEB, 2017a). Additionally, struggles in land-based transport such as pipelines has negatively impacted Canada’s ability to export LNG (CAPP, 2018). Canada is a late entrant to global LNG markets, and the next several years will be critical to the development of the Canadian LNG industry.

Canadian projects have certain advantages, including abundant and relatively low cost natural gas supplies (NEB, 2017b). In addition, west coast Canadian LNG projects have a shorter shipping distance to Asian markets compared to US gulf coast facilities, which provides Canada with a competitive advantage in the Pacific LNG trade (NEB, 2017b). This competitive advantage is important for Canada’s LNG development as east Asian states are major consumers of LNG and their primary trade partners in the ASEAN area are anticipated to become energy importers by 2030 (IEA, 2017b, 2017c). Access to low cost natural gas and a shorter shipping distance provide Canada with an opportunity to become a major player in the global LNG trade as exporters in the Pacific. Therefore, while current conditions may not be as favourable as they have been in recent years, future opportunities for Canadian LNG should be enhanced by rapidly increasing demand and cost-saving technological advancement.

Disadvantages facing Canadian projects include high costs to develop projects in remote locations with limited infrastructure, and where the construction of new pipelines is required to supply the necessary gas (NEB, 2017b). With LNG prices falling in recent years, the margins needed to justify this type of capital-intensive development have eroded. Increased competition has also made it difficult for Canadian projects to sign long-term supply contracts (NEB, 2017b). Overall, market conditions make large-scale capital development projects difficult to achieve due to the low margins, increased competition, and market uncertainty. The feasibility of these projects is also limited by social pressures and Canada’s regulatory environment where opposition and complex approvals processes increase the cost of development (NEB, 2017b). However, these disadvantages may not be experienced by certain projects as individual project economics and risks could be reduced by factors such as the type of land utilized (e.g., for production, storage, and/or land-based transportation), ability/success in winning long-term contracts, regulatory implementation, and margins.

Regarding GHGs, the increased LNG consumption is anticipated to displace higher GHG intensity modes of energy production such as coal. Therefore, the expansion of the use of LNG is likely to reduce global GHG emissions considering current displacement trends. In addition, the increased efficiency is likely to reduce GHGs by achieving higher energy yields relative to each unit of natural gas consumed. The transport of LNG into the
Pacific would likely increase the viability of natural gas expansion in the region and may positively impact Canadian natural gas use through economies of scale driven by foreign demand.

### 4.4.3.3.4.1.2 Canadian Demand

As of 2016, 81% of Canadian natural gas consumption uses domestic natural gas sources. The 19% imported comes almost entirely (99%) from the US (NRCan, 2017). All imports are into the east coast, with the majority sourced from the northeastern US while additional LNG is imported through Canaport LNG terminal in New Brunswick (NRCan, 2017). Therefore, consumption in western Canada is almost certainly entirely sourced from domestic production.

In the 2017 NEB Reference Case, energy demand growth is forecasted to slow to 0.3% between 2016 and 2040 (NEB, 2017a). Beyond existing trends in growth, improved energy efficiency will drive the demand for electricity down (NEB, 2017a). For example, since 1990, high and medium efficiency furnaces have increased efficiencies by 30% to 50%, which is anticipated to continue to grow as lower efficiency furnaces are replaced (NEB, 2017a).

While most LNG production in western Canada is consumed in western Canada, large volumes are also exported to the western US. Currently much of the LNG movement in western Canada is completed via truck including from the Tilbury LNG Plant. From the Tilbury LNG Plant, LNG is transported by truck an average of 100 km ((S&T)2 Consultants Inc., 2017). LNG is often transported throughout the province of BC, or to the Northwest Territories (WesPac, 2018 pers. comm.).

### 4.4.3.3.4.2 International Market

#### 4.4.3.3.4.2.1 Global Natural Gas Demand

Natural gas supplies 22% of the energy used worldwide, playing a crucial role in the global energy industry. Natural gas's growth is linked in part to its lower environmental costs relative to other fossil fuels, particularly for air quality as well as GHG emissions (IEA, 2018b). Demand for LNG is growing, with 47 countries and territories expected to import LNG by 2022 compared to 38 in 2016 (IEA, 2017a). The expansion of the supply of LNG (Section 4.4.2.2) has also aided in adding flexibility in the market necessary for importing countries to compensate with supply availability and capacity issues in 2016 (IEA, 2017a). The increased flexibility is driven by enhanced production and export from the US and Australia changing the terms under which contracts are formed and allowing states to source their increased demand for natural gas from a wider array of locations (IEA, 2017a).

Within the IEA’s New Policies Scenario, natural gas use would rise by 45% to 2040; with more limited room to expand in the power sector, industrial demand would comprise the largest portion of this growth (IEA, 2018c). Natural gas would become a quarter of global energy demand and the second-largest fuel in the global mix after oil (IEA, 2018c). The projected demand increases for natural gas are threatened due to renewables, which in some countries become a cheaper form of new power generation than gas by the mid-2020s. Efficiency policies also play a part in constraining gas use in the IEA New Policies Scenario, as electricity generated from gas would grow

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2 In the New Policies Scenario, global energy needs rise more slowly than in the past but still expands by 30% between today and 2040. This is the equivalent of adding another China and India to today’s global demand (IEA, 2018c).
by more than half by 2040, related gas use would rise by only one-third, due to more reliance on highly efficient plants (IEA, 2018c).

LNG accounts for almost 90% of the projected growth in long-distance gas trade to 2040 with few exceptions (IEA, 2018c). The locational optionality\(^2\) of LNG is crucial to the long-term prospects for natural gas, allowing for a flexible market that would increase liquidity, offer supply security, and aid in price discovery (IEA, 2018c). These components aid in a responsive market that is adaptive to changes in the global energy market.

### 4.4.3.3.4.2.2 Global Natural Gas Supply

The market for LNG is growing in volume, with nearly 200 billion m\(^3\) of liquefaction capacity additions anticipated by 2022, with the emergence of Australia and the US (IEA, 2017a). The emergence of the US as a major player in global LNG trade is beginning to have a major impact both in terms of the volumes of LNG available to the market, and flexible conditions under which LNG is made available to the market (IEA, 2017a). The sale of gas free on board\(^4\), the absence of destination clauses, pricing formulas based on gas-to-gas competition, and the scalability of new investments in both liquefaction and regasification offer growing flexibility that can improve global gas security (IEA, 2017a). As gas trade increases, so do the concerns about natural gas security, as a demand or supply change in one region may now have repercussions in others (IEA, 2018b). The increase in trade and globalization may impact pricing discrepancies, altering the feasibility of North American export facilities and gas developments. Within the IEA’s New Policies Scenario, improvements in efficiency, renewables, and access to gas are likely to lead to a reduction in coal usage (IEA, 2018c).

In the New Policies Scenario, gas supply would also become more diverse as the amount of liquefaction sites worldwide would double by 2040, with the main additions coming from the US and Australia, followed by Russia, Qatar, Mozambique, and Canada (IEA, 2018c). Price formation would be based increasingly on competition between various sources of gas, rather than indexation\(^5\) to oil (IEA, 2018c). The increased diversity of gas sources changing the structures of price formation within the gas market contribute to increased market liquidity described in Section 4.4.2.1. The US is a key driver behind achieving the liquidity and optionality of the gas market. With destination flexibility, hub-based pricing, and spot availability, US LNG acts as a catalyst for many of the anticipated changes in the wider gas market (IEA, 2018c).

### 4.4.3.3.4.2.3 American Market

#### 4.4.3.3.4.2.3.1 Production

Since 2010, the US production of shale has drastically increased (IEA, 2018c). Expansion on this scale is having wide-ranging impacts within North America, fuelling major investments in petrochemicals and other energy-

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\(^2\) Optionality refers to opportunity for additional optional market opportunities that become apparent after the initial construction of the liquefaction facility. In the case above, the additional market opportunities are locations and markets for the distribution of LNG.

\(^4\) Free on board refers to the point at which ownership of the LNG will be transferred from the seller to the buyer. With free on-board shipping, the seller is responsible for all activities prior to the product being loaded onto the ship. Once it is loaded onto the ship, ownership transfers to the buyer.

\(^5\) Indexation is the process of tying movements in the price of one good (or a series of goods) to the movement in another good (or series of goods).
intensive industries. It is also reordering international trade flows and challenging incumbent suppliers and business models (IEA, 2018c). The increased production is shown in the LNG trade where the US became a net exporter for the first time in 2016 (IEA, 2017b). By the mid-2020s, the US is projected to become the world’s largest LNG exporter (IEA, 2018c). The US is an active player in global LNG markets with multiple LNG export terminals operating and under construction in the Gulf of Mexico. American LNG exports predominantly go to South America (30%) and Asia (15%) (NEB, 2017b). However, as of July 2017, no proposed projects on the US west coast are currently under construction, providing an opportunity for Canadian west coast projects (IEA, 2018c).

Future growth in US natural gas production is projected to be driven by the development of shale gas resources. However, a great deal of uncertainty surrounds this growth. In particular, future domestic shale gas production depends on the quality of the resources, the evolution of technological and operational improvements to increase productivity per well and to reduce costs, and the market prices determined in a diverse market of producers and consumers, all of which are highly uncertain (US Energy Information Administration, 2018).

As noted in Section 4.3.2.1, US LNG helps to accelerate a shift towards a more flexible, liquid, global market. The ability to unlock new resources cost-effectively pushes combined US oil and gas output to a level 50% higher than any other country has ever managed; already a net exporter of gas, the US will become a net exporter of oil in the late 2020s (IEA, 2018c). Once all liquefaction projects currently under construction come online, the US is projected to have the world’s third-largest LNG export capacity (US Energy Information Administration, 2017).

### 4.4.3.4.2.3.2 Markets

In the US, 97% of natural gas imports come from Canada, contributing 11% of American consumption (NRCan, 2017). Canada’s natural gas exports are generally directed to the western US or the Midwest (NRCan, 2017). Natural Resources Canada contends US LNG exports and exports of natural gas to Mexico may create additional opportunities for Canadian exports to the US to address gaps in US domestic supply (NRCan, 2017).

Recently, the expansion of US production has decreased demand for Canadian natural gas (NEB, 2017b). The US has begun to convert existing regasification sites used for the import of LNG to liquefaction facilities for the export of LNG (NEB, 2017b).

### 4.4.3.4.2.4 Asia and Oceania

#### 4.4.3.4.2.4.1 Production

Production occurs most frequently in the southern ASEAN states and Australia (IEA, 2017b). Australia has large natural gas resources, which enable the country to be self-sufficient in gas supply as well as a leading exporter of LNG. LNG exports have rapidly increased in recent years as a result of new LNG terminals being constructed across Australia, including in the eastern market, which was previously a centre of domestic consumption (IEA, 2018c). Most near to medium-term increases in global supply in the Pacific will come from capacity already under construction in Australia (NEB, 2017b).

Australia has been exporting LNG since 1989. Export volumes were stable around 10 billion m$^3$ annually from the mid-1990s until 2004, when they began to increase and doubled in five years (IEA, 2018a). The Australian LNG export market changed even more significantly in 2009 to 2011, when commitments to build seven more large
LNG plants with total investments of more than USD 150 billion were announced. The new plants were planned to become operational over the period of 2015 to 2019, and to increase total export capacity to nearly 120 billion m³ (IEA, 2018a). This rapid growth has made Australia the second-largest LNG exporter in the world after Qatar.

Japan is the largest importer of LNG from Australia, with annual imports of around 25 billion m³, accounting for nearly three-quarters of Australia’s total exports in 2015 (IEA, 2018a). The country exports LNG mainly through long-term contracts, and the contracted volume is set to almost triple by 2017 compared to 2015, to around 100 billion m³. Exports to Japan will grow to almost 50 billion m³ in the coming years, but exports to China will increase more rapidly to around 24 billion m³ annually in 2019 to 2022. Japan, however, will continue to be the largest importer of Australian LNG, accounting for 44% of total contracted volumes in 2022 (IEA, 2018a).

The ASEAN region is a net exporter of natural gas (IEA, 2017c). Exports are driven by Malaysia and Indonesia, which account for about 70% of the region’s reserves and two-thirds of the region’s production in 2016. Myanmar and Brunei Darussalam are also small exporters of LNG (IEA, 2017c). Currently, ASEAN countries face several key challenges which may impact their production and export of natural gas, including a lack of long-term planning, physical bottlenecks, lack of stakeholder coordination, and extensive lead times on planning, construction, and commissioning (IEA, 2017c). Myanmar illustrates these issues, as despite an abundance of gas resources, delays in expanding production and long-term contracts have required the export of gas to China and Thailand (IEA, 2017c). As result, Myanmar has a domestic shortage and has had to import more costly energy sources such as oil (IEA, 2017c). Given the rate of energy consumption growth in the region described in Section 4.4.2.4.2, the IEA anticipates the ASEAN region will become a net importer of natural gas by 2030 as growth in demand outpaces the available supply (IEA, 2017c).

4.4.3.3.4.2.4.2 Asia Pacific Markets

The predominant importers of LNG are Japan, Taiwan, China, and South Korea within the Asia Pacific trade area. China’s demand for LNG imports grew 25% (8.3 billion m³) between 2015 and 2016 (IEA, 2017b). Both Japan and South Korea in 2016 increased their imports by almost 2%, receiving 10.2 billion m³ more LNG from Australia than in 2015 (IEA, 2017b). Currently, Asian markets are the major consumer of LNG accounting for 75% of the global LNG trade (US Energy Information Administration, 2017).

The large Asian markets (Japan, South Korea, Taiwan, and to a lesser degree, China and India) have traditionally relied on LNG, which has been priced under long-term contracts tied to crude oil prices (US Energy Information Administration, 2017). With Asia Pacific as the world’s largest LNG consuming region, governments in the region have sought to liberalize their domestic markets to promote competitive LNG trading that can provide price discovery for LNG (US Energy Information Administration, 2017). The desire to establish market hubs suggests demand for LNG is likely to remain relatively high compared to other sources of energy. The east Asian region can, therefore, be considered a potential market for Canadian LNG over the course of energy usage forecasting.

Southeast Asia is another rising heavyweight in global energy, with demand growing at twice the pace of China. Overall, developing countries in Asia account for two-thirds of global energy growth (IEA, 2018c). This includes 80% of the projected growth in gas demand expected to occur in developing economies, led by China, India, and other countries in Asia in the IEA New Policies Scenario (IEA, 2018c). In the Asia Pacific market, much of the natural gas needs to be imported, and infrastructure is often not yet in place. This reflects the fact that gas aligns
with policy priorities in this region, generating heat, power, and mobility with fewer CO₂ and pollutant emissions than other fossil fuels, helping to address widespread concerns over air quality (IEA, 2018c).

China is entering a new phase in its development. The president’s call for an “energy revolution,” the “fight against pollution,” and the transition towards a more services-based economic model is moving the energy sector in a new direction. The emphasis in energy policy is now firmly on electricity, natural gas, and cleaner, high-efficiency and digital technologies (IEA, 2018c). China’s choices will play a huge role in determining global trends, and could spark a faster clean energy transition. The scale of China’s clean energy deployment, technology exports, and outward investment makes it a key determinant of momentum behind the low-carbon transition (IEA, 2018c). In the IEA New Policies Scenario, China provides a quarter of the projected rise in global gas demand, and its projected imports of 280 billion m³ in 2040 are second only to those of the European Union, making China a linchpin of global gas trade (IEA, 2018b).

4.4.3.5 Framing Alternatives

As part of the upstream GHG emissions assessment, alternatives must consider any changes upstream along the supply chain of LNG production activities. The supply chain is included in Figure 1. The Tilbury Marine Jetty occurs at the LNG transport stage shown in the figure, which represents the transport of LNG to the endpoint consumption market.

Figure 1: Liquefied Natural Gas Supply Chain

The Tilbury LNG Plant has been operational since 1971 processing natural gas for rate base customers and truck transport. The plant is being expanded, and the Project is not anticipated to alter the volume that is processed related to this expansion (FortisBC, 2018b). Therefore, the same volume of gas will be extracted from the gas field and transported to the Tilbury LNG Plant for liquefaction regardless of whether the Project is constructed or not, as the current expansion project is almost completed and in the permitting stage (FortisBC, 2018a; Metro Vancouver, 2018). In addition, the storage of LNG will occur on the Tilbury LNG Plant site (FortisBC, 2018b). Therefore, the movement of LNG from the liquefaction plant to the storage facility will remain constant in all alternatives considered. The Project is adjacent to the Tilbury LNG Plant. The close proximity of these two facilities means the movement of LNG to the transport vehicle or vessel is not likely to result in a significant change to GHG emissions. Overall, all potential changes in GHG emissions due to the Project are anticipated to occur at the LNG transport stage.
The scope of the Project only includes the movement of LNG from FortisBC facility to the loading platforms, the loading of vessels, and transport of LNG. The assessment of alternatives considers two different options. The first is the No Project Case: Trucks and Alternate Port, where production of the Tilbury LNG Plant will be transported by truck to its domestic endpoint (25% of LNG throughput) and transported by truck in an ISO container to an alternate port in the Vancouver area for distribution internationally by merchant container vessel (75% of throughput). This is the null case where existing operations continue as they do presently. The second is the Project Case, where LNG is transported from the Tilbury Marine Jetty. This case considers how international shipping will impact GHG emissions. These alternatives consider current and future LNG supply and demand to forecast the likely endpoint for LNG, and allow the emissions associated with transport to be quantified. It should be noted only the incremental emissions change will be considered which confines the model to considering only the anticipated volume of LNG associated with the Project (3.5 million tonnes per year), assuming the Project develops as expected based on market demand.

Finally, in all cases, the quantity transported is not anticipated to effect world markets as the volume of LNG transported is small compared to global trade flows. Effects to trade flows are anticipated to be limited to the Project’s endpoint and are not expected to “crowd out” other trade flows beyond direct displacement. As result, the additional transportation associated with LNG from the Tilbury LNG Plant will be the change in incremental GHG emissions. This means all current operating activities and presumed activities considered in emissions scenarios in Section 4.4 are not likely to be altered by the Tilbury Marine Jetty.

Appendix 4.4.3-1 provides the framework for the GHG emissions estimates included in Section 4.5, including all formulas. Key assumptions for specific cases are also included in the sections below.

### 4.4.3.3.5.1 Alternative One – Alternate Port (No Project Case)

#### 4.4.3.3.5.1.1 Assumptions and Technical Limitations

In the No Project Case, it is assumed that 25% of the LNG throughput will be transported by truck an average distance of 100 km to a consumption endpoint for domestic consumption. The remaining 75% of the LNG throughput will be transported by an ISO container truck to an alternate port an average distance of 50 km from the Tilbury LNG Plant, where it will be loaded onto a container vessel for shipping to a consumption endpoint.

It is assumed that the alternate port will send out approximately 66 merchant container vessels annually, assuming 2,200 ISO containers of LNG per vessel. The LNG ISO containers cannot be carried below deck on the container ship, putting a limitation on the number of LNG ISO containers that can be shipped on each vessel (a vessel could hold a total of 6,500 containers in theory). It was assumed that the 2,200 LNG ISO containers would be present and the remaining capacity of the vessel would be 50% full. As discussed in Appendix 4.4.3-1, the emissions have been scaled to account for only the emissions attributable to the 2,200 LNG ISO containers per vessel. The merchant container vessels will transport LNG to east Asia\(^6\). Merchant container vessels are anticipated to travel an average of 8,953 km from Tilbury with the primary endpoint of Japan\(^8\) (counted as an additional 2,778 km

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\(^6\) A crowd-out effect occurs when one form of investment makes another undesirable or unprofitable. In this case, the construction of LNG infrastructure to enter into an LNG market may make other operations unprofitable or undesirable.

\(^7\) This assumption is based on current import/export trends where ASEAN nations and Australia tend to be net exporters and likely are not feasible destinations for Canadian LNG.

\(^8\) It was assumed that roughly 50% of all exports via carrier would go to Japan, with 8.3% going to each of the other Asian country destinations including China, South Korea, Singapore, and Taiwan.
between Tilbury and Shimizu). These averages were taken by using potential endpoints for carriers given the trends in Pacific LNG trade and information from WesPac (WesPac, 2018 pers. comm.). While Japan was identified as the primary destination, LNG shipping trends suggest China, South Korea, Singapore, and Taiwan are also feasible destinations for portions of production over the life of the Project. A summary of the distance to potential transport routes is shown in Table 4.4.3-6.

**Table 4.4.3-6: Shipping Distances**

<table>
<thead>
<tr>
<th>Travel Route (a)</th>
<th>Distance (km) (b)</th>
<th>Proportion Assumed (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Distances from Tilbury</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tilbury to Japan (Shimizu)</td>
<td>7,841</td>
<td>50</td>
</tr>
<tr>
<td>Tilbury to South China (Guangzhou)</td>
<td>10,553</td>
<td>8.3</td>
</tr>
<tr>
<td>Tilbury to North China (Qingdao)</td>
<td>9,382</td>
<td>8.3</td>
</tr>
<tr>
<td>Tilbury to Shanghai</td>
<td>9,262</td>
<td>8.3</td>
</tr>
<tr>
<td>Tilbury to South Korea (Pusan)</td>
<td>8,434</td>
<td>8.3</td>
</tr>
<tr>
<td>Tilbury to Singapore</td>
<td>12,916</td>
<td>8.3</td>
</tr>
<tr>
<td>Tilbury to Taiwan (Taichung)</td>
<td>9,842</td>
<td>8.3</td>
</tr>
<tr>
<td><strong>Distances to Shimizu</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Malaysia (Telok Anson) to Shimizu</td>
<td>5,806</td>
<td>30</td>
</tr>
<tr>
<td>Indonesia (Tanah Merah) to Shimizu</td>
<td>4,971</td>
<td>20</td>
</tr>
<tr>
<td>Eastern Australia (Curtis Island) to Shimizu</td>
<td>7,056</td>
<td>25</td>
</tr>
<tr>
<td>Western Australia (Karratha) to Shimizu</td>
<td>6,964</td>
<td>20</td>
</tr>
<tr>
<td>Northern Australia (Darwin) to Shimizu</td>
<td>5,635</td>
<td>5</td>
</tr>
<tr>
<td><strong>Bunker Vessel Transport Distances</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tilbury to US Ports (c)</td>
<td>2,200</td>
<td>66.7</td>
</tr>
<tr>
<td>Tilbury to Port of Vancouver</td>
<td>100</td>
<td>33.3</td>
</tr>
<tr>
<td><strong>Truck Transport Distances</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average truck distance from Tilbury (for LNG that is transported by truck for domestic use)</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Average truck distance from Tilbury (for LNG that is transported by truck to the alternative port)</td>
<td>50</td>
<td>100</td>
</tr>
</tbody>
</table>

a) All travel routes are estimates of potential port destinations in a regional area using a specific port as an indicative endpoint.
b) Distances obtained from SeaRates Logistics Explorer (SeaRates LP, n.d.) and are rounded to the nearest whole number.
c) Detailed estimates of US ports are not provided due to the lack of physical infrastructure at this time. Most potential LNG destinations have not yet been constructed.
LNG = liquefied natural gas.
Given these assumptions, 7,777,778 m³ (or 3,500,000 tonnes) will be transported from the Tilbury LNG Plant annually. As noted above, this volume is small compared to the current global trade of LNG where Japan imports nearly 100 billion m³ of LNG.

The model accounts for the emissions generated by shipping LNG by truck to the alternate port, the emissions generated by shipping LNG from the alternate port, and the emission reduction associated with displacing the shipping of LNG from another port to the endpoint. The distance associated with the displaced shipping from another port is calculated using the distances of Shimizu from key export ports as outlined in Table 6. These distances are used to confine the scope of the model to direct changes in emissions removing the ambiguity of other changes. These changes cannot be accurately measured and, as a result, are described qualitatively as part of the assessment.

It is also conservatively assumed that LNG from the Tilbury LNG Plant will only displace other LNG transported and utilized, not any other higher GHG intensive energy forms such as oil or coal. In addition, the model did not account for the displacement of more carbon intensive LNG sources than the LNG produced at the Tilbury Plant. Finally, energy efficiency and emissions levels are assumed to remain constant throughout the Project lifecycle. This means technological and regulatory change are not accounted for in the model. As described in Sections 4.3 and 4.4, the regulatory and technological confines of LNG related emissions are changing and can have large impacts on overall emissions levels.

4.4.3.3.5.1.2 Summary of Key Existing Market Factors

The absence of the Tilbury Marine Jetty affects the viable market endpoints for the Tilbury LNG Plant production. The change in viable endpoints will affect the GHG emissions as the transportation-related emissions will change. As described in Section 4.4.2.3, the US has been rapidly increasing production, becoming a net exporter of LNG in 2016 and is expanding production and exporting operations. With the US becoming a net exporter in the Pacific and to Mexico, there may be gaps in domestic supply that can be filled by Canadian exports. For the portion of LNG throughput transported internationally through an alternate port, additional market factors need to be considered.

As described in Section 4.3, LNG production is increasing as it remains part of the climate change strategies for key Pacific producers and consumers. East Asian markets including South Korea, Japan, and China have identified LNG as key to reducing their reliance on coal and achieving Paris Agreement targets.

Section 4.4 notes Canada’s proximity to East Asian consumers relative to major competitors such as the US and Australia provides a competitive advantage, suggesting Tilbury LNG will be exported across the Pacific to these states. Therefore, the Tilbury LNG Plant is likely to aid in meeting the increased demand in Asia anticipated by the IEA in its New Policies Scenario. Finally, increased market flexibility means endpoints will vary and fewer long-term contracts will shape the market. These changes to the structure of the market are likely due to the increased global demand for natural gas and the increased role of the US as an exporter in both the Atlantic and Pacific markets.

Regarding emissions, it is anticipated that LNG exported from an alternate port is likely to displace existing fossil fuel production, including coal, leading to a reduction in total global GHGs released. This is consistent with policy frameworks submitted to the United Nations as described in Sections 4.3.2.2 and 4.4.2.4.2.
4.4.3.3.5.1.3 Effect of Alternative

Emissions in the No Project Case are anticipated to be 116,324 t CO₂e annually (Appendix 4.4.3-1, Table 7). Cumulatively, this amounts to 3,606,030 t between 2023 and 2053 during Project operations. Only a portion (9%) of emissions associated with the truck transportation to the domestic market and truck transportation to a local port are considered national in this case. The remaining emissions (91%) are considered global in this case as the transit by merchant container vessel is international.

In the No Project Case, it is currently assumed that vessels would transport the maximum number of ISO containers of LNG on deck, and that 50% of the remaining bulk cargo capacity is filled with other goods. Emissions could be even higher under the no Project case if the remaining vessel capacity is less than 50% full.

Emissions could be reduced in the future due to technological advancement coupled with regulatory change. Improved technology such as electric trucks or increased fuel efficiency may result in reduced emissions. The rate at which these advancements are adopted will also impact emissions as a faster adoption rate will reduce emissions sooner. Regulatory changes can aid in faster adoption by mandating adoption of emissions reducing technologies. Regulatory and technological changes as drivers of reductions in emissions levels has been described as part of Sections 4.3 and 4.4. Regulatory and technological changes are anticipated to reduce emissions levels up to 5% in Canada and will alter the global energy sector likely leading to reduced emissions.

The No Project Case provides the baseline for emissions associated with transit from the Tilbury LNG Plant. The Project Case in Section 4.5.2 will provide the incremental changes associated with the Project that are likely to alter national and global emissions levels. As noted in Section 4.4.1, Canada is a small player in the global LNG market. This means GHG emissions associated with the transport of LNG via an alternate port are a much smaller as a percentage of global LNG transport related emissions. Section 4.4.2.4.1 notes Australia was expected to export 100 billion m³ of LNG by 2017, or over 26,000 times the volume exported from the Tilbury LNG Plant. Therefore, shipping emissions associated with the Project are very small on a global scale.

Sensitivity Analysis

No sensitivity case is considered for the No Project Case as the Tilbury LNG Plant is expected to continue to ship LNG to the SeaSpan facility and industrial facilities in the Northwest Territories in very limited quantities (WesPac, 2018 pers. comm.). Overall distribution by truck will continue to average 100 km with no predicted discernable variances ((S&T)2 Consultants Inc., 2017; WesPac, 2018 pers. comm.). For international shipping, the sensitivity to changing shipping demands is explored as part of the Project Case, which uses the same assumptions on distances and market demands as the No Project Case.

4.4.3.3.5.2 Alternative Two – Tilbury Marine Jetty (Project Case)

4.4.3.3.5.2.1 Assumptions and Technical Limitations

In the Project Case, it is assumed that the Tilbury Marine Jetty will send out approximately 72 carriers and 73 bunker vessels annually. This is slightly higher than the actual projected number of Project related vessels of 68 and 69 carriers and bunker vessels, respectively, since the number of vessels have been increased to account for an annual transportation volume of 7,777,778 m³ (3,500,000 t). Similar assumptions applied to the merchant container vessels under the No Project Case in Section 4.5.1.1 for shipping distances are applied to the bunker
and carrier vessels in the Project Case. The average distance travelled is anticipated to be 1,501 km for bunker vessels and 2,778 km for carriers (additional distance to Shimizu, Japan), as discussed in Section 4.5.1.1 for the No Project Case and shown in Table 4.4.3-6. Similarly, 7,777,778 m³ (3,500,000 t) LNG throughput is assumed to be transported from the Tilbury Marine Jetty annually. As noted above, this volume is small compared to the current global trade of LNG where Japan imports nearly 100 billion m³ of LNG.

A similar emission model is applied to international shipping emissions from the No Project Case. The model accounts for the emissions generated by shipping LNG from the Tilbury Marine Jetty and the emission reduction associated with shipping LNG from another port to the endpoint. Emissions from transport by truck to an alternate port, or to endpoint destinations are not included in the Project Case, unlike the No Project Case.

Similar to the No Project Case, it is assumed that LNG from the Tilbury LNG Plant will displace other LNG transported and utilized, not any other forms of energy. Finally, energy efficiency and emissions levels are assumed to remain constant throughout the Project lifecycle. This means technological and regulatory change are not accounted for in the model. As described in Sections 4.3 and 4.4, the regulatory and technological confines of LNG-related emissions are changing and can have large impacts on overall emissions levels. Section 4.5.2.3 directional changes associated with the model’s estimated emissions should the assumptions included in this section be relaxed as part of a qualitative assessment of alternatives.

4.4.3.3.5.2.2 Summary of Key Existing Market Factors

Similar market factors are considered to the No Project Case. As described in Section 4.3, LNG production is increasing as it remains part of the climate change strategies for key Pacific producers and consumers. East Asian markets including South Korea, all identified LNG as key to reducing their reliance on coal and achieving Paris Agreement targets.

Section 4.4 notes that Canada’s proximity to East Asian consumers relative to major competitors such as the US and Australia provides a competitive advantage, suggesting Tilbury LNG will be exported across the Pacific to these states. Therefore, the Tilbury Marine Jetty is likely to aid in meeting the increased demand in Asia anticipated by the IEA in its New Policies Scenario. Finally, increased market flexibility means endpoints will vary and fewer long term contracts will shape the market. These changes to the structure of the market are likely due to the increased global demand for natural gas and the increased role of the US as an exporter in both the Atlantic and Pacific markets.

Regarding emissions, it is anticipated that LNG exported from the Tilbury Marine Jetty is likely to displace existing fossil fuel production including coal, leading to a reduction in total global GHGs released. This is consistent with policy frameworks submitted to the as described in Sections 4.3.2.2 and 4.4.2.4.2.

4.4.3.3.5.2.3 Effect of Alternative

In the Project Case, a reduction of 36,142 t CO₂e is predicted compared to the No Project Case (emissions of each alternative are provided in Appendix 4.4.3-1). Cumulatively during the Project operational period of 30 years, a reduction of 1,132,192 t CO₂e would be achieved between 2023 and 2053.
As noted in Section 4.4.1 and above in Section 4.5.1.3, Canada is a small player in the global LNG market. This means GHG emissions associated with the transport of LNG via the Tilbury Marine Jetty Project are a much smaller as a percentage of global LNG transport related emissions. Section 4.4.2.4.1 notes Australia was expected to export 100 billion m$^3$ of LNG by 2017, or over 26,000 times the volume exported from the Tilbury Marine Jetty. Therefore, shipping emissions associated with the Project are very small on a global scale.

**Sensitivity Analysis**

The sensitivity analysis considers changes to the transportation blend (i.e., mix of bunker vessels versus carriers) based on trend trends in world markets as endpoints for LNG production. Considering the market trends including increased east Asian demand and rising American supply, it is assumed the number of bunker vessels will decline and the number of carriers will increase (as indicated in Section 4.4.2). Figure 2 shows how the transport blend is likely to effect GHG emissions. In all three cases, the average distance travelled will remain unchanged.

The base case for the sensitivity analysis is the Project Case described above. This case assumes the constant transportation blend detailed in the Project Description (Section 2.0). In this case, the Project Description blend of transportation is anticipated not to change over the Project operational period.

In the first sensitivity analysis (Sensitivity Analysis 2%), it is assumed there will be a 2% decline annually in the volume of LNG transported by bunker vessels, to compensate for the increase American production and hence a decrease in demand for LNG from Canada (Section 4.4.2.3). This 2% decline is replaced with increased carrier traffic which meets the increased east Asian demand. It is assumed in this case the Project will also continue to ship the same volume of LNG, regardless of shipping destination (WesPac, 2018 pers. comm.). Therefore, changes in transportation blend occur once the annual decline in volume shipped by bunker vessel is large enough (i.e., approximately 100,000 m$^3$ of LNG) such that a carrier can replace the equivalent number of bunker vessels (approximately 13 bunker vessels). In this case, incremental emissions range between a reduction of 36,142 and 36,955 t CO$_2$e annually when compared to the No Project Case. The total emissions between 2023 and 2053 are estimated to be a reduction of 1,132,192 t CO$_2$e. Over the Project operational period, additional carriers are projected to replace bunker vessels in 2033 and 2046. Each additional carrier reduces emissions by 407 t CO$_2$e annually through energy efficiency relative to bunker vessels.

In the second sensitivity analysis (Sensitivity Analysis 5%), it is assumed there will be a 5% decline annually in the volume of LNG transported by bunker vessels, to compensate for a faster decrease in American demand for LNG from Canada. All other assumptions from Sensitivity Analysis 2% are the same in Sensitivity Analysis 5%. In this case, incremental emissions range between a reduction of 36,142 and 37,768 t CO$_2$e annually. The total emissions between 2023 and 2053 are estimated to be a reduction of 1,148,452 t CO$_2$e when compared to the No Project Case. Over the operational period of the Project under Sensitivity Analysis 5%, additional carriers are projected to replace bunker vessels in 2027, 2032, 2039, and 2049. Consistent with Sensitivity Analysis 2%, each additional carrier reduces emissions by 407 t CO$_2$e annually through energy efficiency relative to bunker vessels.

The sensitivity cases demonstrate the role of larger transportation vessels in reducing emissions as the additional capacity of a carrier reduces emissions even with a longer transportation distance. When a 5% increase annually is assumed for carrier traffic, emissions are reduced further by approximately 28,049 t CO$_2$e between 2023 and 2053, compared to the Project Case (where emissions remains constant). Considering the sensitivity case reductions in emissions and market trends summarized in Section 4.5.1.2, it is likely the emissions associated with...
the Project will decline over time as Pacific LNG trade is likely to increase due to increased demand in the East Asia region and decreased demand for foreign natural gas in the US.

Figure 2 shows the change in emissions projects for three select periods (2023, 2038, and 2053) for each of the cases considered, including the sensitivity analyses. Additional information on GHG emissions projections for each of the Project cases can be found in Appendix 4.4.3-1.

Figure 2: Projected Emission by Case

Note: Appendix 4.4.3-1 contains the annual forecasted emissions for all cases including sensitivity analyses.

The model only considered the direct displacement of transportation of LNG associated with the Tilbury Marine Jetty. The emissions from the No Project Case were subtracted from the total emissions from each case considered on a year by year basis to estimate the incremental emissions associated with each choice. However, Figure 2 represents the total GHG emissions from each case, and the incremental emissions can be calculated by the difference in the total emissions compared to the Alternate Port (No Project Case) emissions. It should be noted that the model does not account for changes in production or demand or for new shipping endpoints. Changes in production and demand may result in LNG displacing other, higher emitting forms of energy. Changes in endpoint may reduce emissions level by reducing the total shipping distance of LNG globally through competitive advantages in shipping distance. The ambiguity described aligns with the description of the existing LNG market as LNG is often used to displace higher emitting fossil fuels and common endpoints have expanding demand. Additionally, the increased competitiveness and optionality of the LNG market aligns with market trends described in Sections 4.3 and 4.4.

As noted in Section 4.5.1.1, the No Project Case and Project Case models utilize the assumption that LNG from Tilbury will replace other LNG consumption. This assumption, while useful for estimation, is not reflective of the complex nature of energy use across nations. While energy displacement modelling is not required to assess changes in GHG emissions from the Project as described in Section 4.5.1.1, IEA projections described in Section 4.4.2.1 suggest natural gas is being used to displace fossil fuels with higher emission levels. For example, in 2014, Japan generated 88% of its energy from fossil fuels including 46.2% from LNG (Ministry of Economy Trade and
Industry, 2016). This means 42% of energy use is likely to have higher GHG intensity than LNG. Japan’s current and planned energy blend also strengthens the assumption that additional LNG is likely to displace other fossil fuels as almost half of energy is already generated through LNG (Ministry of Economy Trade and Industry, 2016).

As reflected in Section 4.5.1.3, technology will be a mitigating factor in emissions levels associated with transit. However, additional potential reductions are available for marine shipping. The European Commission notes CO\(_2\) emissions could be reduced by up to 75% by applying operational measures and implementing existing technologies (European Commission, 2016; International Maritime Organization, 2011). The International Maritime Organization introduced mandatory energy efficiency regulations on maritime trading vessels in recognition of the potential to reduce emissions (International Maritime Organization, 2011). The International Maritime Organization is considering other market measures to incentivize adaptation (International Maritime Organization, 2011). This could indicate that the role of technological advancement is more likely to lead to higher magnitudes of reduced emissions for the Project Case than the No Project Case (since overall the Project Case has a higher magnitude of emissions from shipping). This change would lead to further reduced incremental emissions associated with the Tilbury Marine Jetty. Additionally, the longer travel distances associated with marine transit will also aid in increasing emission reductions associated with transportation in absolute magnitude should engine efficiency technology improve for both trucks and ships.

### 4.4.3.3.6 Evaluating Alternative Cases

The key differentiating factor applied between the two proposed alternative cases is the emissions intensity (t CO\(_2\)e/km) of different LNG transportation options, which generates variance in the GHG emissions. In the Project Case, fewer emission intensive shipping vessels are used to transport the LNG internationally compared to the No Project Case. In addition, the No Project Case results in GHG generation from trucking LNG from the Tilbury LNG Plant to the domestic market and to an alternate port.

In the No Project Case, 116,324 t CO\(_2\)e is emitted annually as part of transportation from the Tilbury LNG Project. Between 2023 and 2053, the transportation of LNG from Tilbury will result in 3,606,030 t CO\(_2\)e emissions. It has been noted that emissions may increase if additional export opportunities are found to fill supply gaps in the US. However, these emissions projections are likely a worst-case scenario as they do not account for changing factors that are expected to reduce emissions over the operational life of the Project. As indicated in Section 4.5.1.3, technological improvement, more stringent regulatory policy, and displacement of other fossil fuels are likely to reduce the actual emissions levels estimated in the Project Case. With displacement, technological improvement, and more stringent regulation, global emissions will be lower than estimated in Section 4.5.2 over the Project operational life.

In the Project Case (including sensitivity analyses), emission reductions, in comparison to the No Project Case, will range between 36,142 and 37,768 t CO\(_2\)e annually. Between 2023 and 2053, the transportation of LNG from the Tilbury Marine Jetty is expected to result in reduced emissions of between 1,120,403 and 1,148,452 t CO\(_2\)e. Similar to the No Project Case, these emissions projections are likely a worst-case scenario as they do not account for changing factors that are expected to reduce emissions over the operational life of the Project through technological improvement, more stringent regulatory policy, and displacement of other fossil fuels. With displacement, technological improvement, and more stringent regulation, global emissions will be even lower than estimated in Section 4.5.2 over the Project operational life.
4.4.3.4 Conclusion

Part A used three different calculation methods to estimate the upstream GHG emissions for the Project. Each approach considered comparable scenarios based on the required input and assumptions included in the methodology. Where possible, emission estimates were made on an annual basis to capture any annual variations. The total upstream GHG emissions for the projects were estimated to range from 1,750.0 kt CO$_2$e to 2,163.8 kt CO$_2$e in 2023, and from 1,689.3 kt CO$_2$e to 2,413.9 kt CO$_2$e in 2053.

The development of LNG facilities and their associated production aligns with the goals of Canadian and global climate strategies as natural gas provides a lower emission intensity alternative to coal and other fossil fuels. The Tilbury Marine Jetty aids in accomplishing these goals by providing a facility for exporting LNG to fossil fueled intense economies transitioning to natural gas, such as Japan. The Tilbury Marine Jetty also aligns with Canada’s economic goals and market conditions where Canada has an opportunity to become a major player in the global LNG trade due to Canada’s proximity to key Asian importers. Canada’s expanding market role may aid these states in accomplishing their national climate goals through the transition to LNG.

In the Project Case (including sensitivity analyses) emission reductions, in comparison to the No Project Case, will range between 36,142 and 37,768 t CO$_2$e annually. Over the Project life, between 2023 and 2053, the transportation of LNG from the Tilbury Marine Jetty is expected to result in reduced emissions of between 1,120,403 and 1,148,452 t CO$_2$e. Projections of emissions associated with the Project and No Project cases yield higher emissions under the assumptions of stagnant technology and energy displacement of only LNG. However, considering the qualitative assessment of these factors, the Project is likely to result in an ambiguous change in emissions levels as displacement and technological change may result in Project emissions being lower than estimated.

Under the No Project Case and Project Case emissions occur both locally (Canada) and globally, and the displacement of other fossil fuel use will occur internationally based on the endpoints considered in each case.
4.4.3.5 References


Section 4.4.3: Upstream GHG Assessment


(S&T)2 Consultants Inc. (2017). Carbon Intensity of FortisBC Tilbury LNG.


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