

**REVIEW OF ESTIMATED GREENHOUSE GAS EMISSIONS ASSOCIATED WITH
THE KSI LISIMS LNG PROJECT**

1. PROJECT DESCRIPTION

1.1 Project Overview

The Nisga'a Nation, Rockies LNG LP, and Western LNG LLC (the proponents) are proposing to develop a floating natural gas liquefaction facility and marine terminal, located at Wil Milit on Pearse Island, in British Columbia (BC). As proposed, the project will have a processing capacity of up to 22.4 billion cubic meters per year of natural gas (LNG) for export to international markets. The project is expected to be in operation for at least 30 years, which will extend the project's lifetime past 2050. The supplying natural gas would be transported to the site via the Prince Rupert Gas Transmission pipeline originating in northeastern BC. The project consists of two floating LNG production, storage and off-loading barges (FLNGs) with electric motors as the main refrigerant compressor drives, as well as other project components including electrical substation and distribution systems, backup diesel power generation, water treatment plants, potential power barges, fuel storage tanks, berths, jetties, roads, and waste management facilities. The project scope also includes a 31 to 44 km 287 kV electricity transmission line between the project site and Nisga'a Lands.

1.2 Applicability

The project's Initial Project Description was submitted in 2021 under the *Impact Assessment Act*, (IAA). Under the IAA, the information requirements of the *Strategic Assessment of Climate Change* (SACC) were applied to this project¹. The federal impact assessment process has been substituted by that of the Government of British Columbia for this project.

As per Section 5 of the SACC, the proponents are required to provide greenhouse gas (GHG) and climate change-related information, including information about federal, provincial or territorial climate policies and measures that will apply to the project, an upstream GHG assessment, a Best Available Technologies / Best Environmental Practices (BAT/BEP) Determination, and a comparison of the project's emissions intensity with similar high-

¹ <https://www.canada.ca/en/services/environment/conservation/assessments/strategic-assessments/climate-change.html>

performing, energy-efficient project types in Canada and internationally. As the project lifetime is expected to extend beyond 2050, the proponents are required to provide a credible plan to achieve net-zero emissions by 2050. Guidance to proponents on preparing this information was made available through the draft *Technical Guide related to the Strategic Assessment of Climate Change: Guidance on quantification of net GHG emissions, impact on carbon sinks, mitigation measures, net-zero plan and upstream GHG assessment* (herein the draft Technical Guide)².

In October 2022, Environment and Climate Change Canada (ECCC) published the draft *Guidance for the submission of information demonstrating best-in-class greenhouse gas (GHG) emissions performance by oil and gas projects undergoing a federal impact assessment*³ (herein draft Best-in-Class Guidance). This guidance describes how new oil and gas projects subject to a federal impact assessment should demonstrate whether and when the project will achieve “best-in-class” emissions performance, or if not, to explain why not. ECCC’s review of this project was informed by this draft guidance.

Section 6 of the SACC states that the Impact Assessment Agency of Canada or the lifecycle regulator, with the support of expert federal authorities, will provide supplemental analysis on the project’s (net and upstream) GHG emissions in the context of Canada’s emissions targets and forecasts. This analysis was prepared by ECCC and fulfills this requirement.

2. GREENHOUSE GAS EMISSIONS

The scope of the substituted assessment of the Ksi Lisims LNG project includes the marine terminal, floating LNG facility, electricity transmission line between project site and Nisga’a Lands, construction activities, and marine transportation for materials, equipment, workers, and movement of LNG and natural gas liquids (within the 12 nautical mile limit).

2.1 GHG emissions from the project

The proponents presented two possible emissions scenarios depending on the main energy source used for the project:

² <https://www.canada.ca/en/environment-climate-change/corporate/transparency/consultations/draft-technical-guide-strategic-assessment-climate-change.html>

³ <https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/oil-gas-emissions-cap/best-class-draft-guidance.html>

- 1) **The Base Case:** assumes that renewable BC Hydro grid power is available at the start of the operation phase; and
- 2) **The Alternative Case:** temporary power barges are used for on-site power generation until the grid connection is achieved. The proponents estimated that this could take until 2032, after which emissions would align with the Base Case.

The estimated maximum annual GHG emissions from the construction phase of the project, which is expected to last four years, is approximately 59 kt carbon dioxide equivalent per year (CO₂ eq. / year) for the Base Case, or 212 kt CO₂ eq. / year for the Alternative Case. The GHG emission sources during this phase include mobile construction equipment, blasting, concrete plant, land-use change, and commissioning activities (either BC Hydro electricity in the Base Case, or temporary power barges in the Alternative Case).

Table 1 summarizes the maximum annual GHG emissions from the construction phase for each scenario. Transmission line construction and land-use change emissions are quantified within the transmission line assessment area (TLAA) between the project site and Nisga'a Lands. These are reported separately from other onshore construction in Table 1, as the proponents did not include the TLAA in their total construction phase emissions estimates.

Table 1. Maximum annual GHG emissions during the construction phase of the project⁴

Category	Equipment	Base Case CO ₂ e (tonnes/year)	Alternative Case CO ₂ e (tonnes/year)
Marine Terminal	Off-road Non-marine	700	700
	Off-road Marine	62	62
Onshore Construction	Off-road Non-marine	9,342	9,342
	On-road	67	67
	Blasting	52	52
	Concrete Plant	43	43
	Land-use Change (excluding TLAA)	8,788	8,788
Shipping Materials	Off-road Marine	1,016	1,016
Personnel Transport	Off-road Marine	63	63
Transmission Line ⁵	Construction Activities	681	681
	Land-use Change (TLAA onshore only)	34,693	34,693

⁴[Technical Data Report - Greenhouse Gases](#)

⁵[Updated Transmission Line Assessment Area Supplemental Information](#)

Commissioning (last year only)	3,370	156,602
Total	58,877	212,109

The proponents estimate that the maximum annual GHG emissions from the operation phase of the project, which is expected to last 30 years or more starting in 2028, will be 253 kt CO₂ eq. / year for the Base Case or 1,868 kt CO₂ eq. / year for the Alternative Case. GHG emission sources for the operations include heat medium fired heaters and thermal oxidizers, flaring, marine transportation, material and personnel movement, and either electrical energy acquired from the electricity transmission line or on-site power generation from natural gas combustion within the power barges.

Table 2. Maximum annual GHG emissions during the operation phase of the project⁶

Category	Equipment	Base Case CO ₂ e (tonnes/year)	Alternative Case CO ₂ e (tonnes/year)
Stationary Combustion	Heat Medium Fired Heaters	68,648	68,648
	Thermal Oxidizers	118,226	118,226
Flaring	Pilot Gas	700	700
Marine	LNG Carriers	30,182	30,182
	Tugboats	4,363	4,363
Material & Personnel Movement	Material Shipping	1,680	1,680
	Personnel Movements	191	191
Power		28,645	1,644,002
Total		252,635	1,867,992

The proponents estimate the GHG emissions for the decommissioning phase of approximately one year, to be just over 45 kt CO₂ eq. This is based on the total emissions during the construction phase (four years under the Base Case), excluding land-use change and commissioning. The proponents state that this estimate is conservative and could change over time since lower-emitting options for equipment may be available approximately 30 years following start-up.

⁶[Technical Data Report - Greenhouse Gases](#)

ECCC Views

ECCC considers that the main sources of GHG emissions during the construction and operation phases of the project, within the scope of the IA process, have been considered by the proponents except for transmission line emissions. Therefore, ECCC is of the view that the proponents have slightly underestimated the project's total GHG emissions in their Revised Application for both scenarios by not accounting for emissions associated with the transmission line within the TLAA in these totals. The proponents did quantify estimated construction emissions for the terrestrial portion of the transmission line between the project site and Nisga'a Lands, but excluded this value from totals due to their view that the transmission line is not under their care and control. As the Application Information Requirements confirm that the construction of the transmission line in the TLAA is within the scope of the project⁷, ECCC has included these values in Table 1 above. Moreover, the proponents did not quantify GHG emissions related to the construction of the submarine portion of the transmission line, which equates to roughly half the length of the transmission line within the TLAA, as the proponents stated that GHG emissions for marine cable laying are generally negligible in comparison to emissions from terrestrial construction activities.

The actual emissions profile produced by the project will depend heavily on the timing of the project's connection to BC Hydro's electricity grid. There remains uncertainty in the timing of this connection, which may be impacted by permitting and approval processes. As can be seen in Table 1 and Table 2, maximum annual emissions are expected to be substantially greater in the Alternative Case, where power barges are needed for on-site power generation. From a GHG perspective, the Base Case would be preferable to the Alternative Case.

2.2 Carbon sinks

The carbon sinks assessment provided by the proponents was completed using the methodology described in the draft Technical Guide⁸. The project area of 43.6 hectares (ha) includes 26.0 ha of forest land and 10.4 ha of bog that would be cleared for the project, excluding the TLAA. Clearing the forest land is not expected to result in a loss of carbon sinks due to the maturity of the vegetation, however the loss of the bog lands was initially estimated by the proponents to result in a total loss of 218 t of carbon storage (800 t CO₂ released if all carbon is oxidized).

⁷ See section 6.6.3 of the [Application Information Requirements](#).

⁸ <https://www.canada.ca/en/environment-climate-change/corporate/transparency/consultations/draft-technical-guide-strategic-assessment-climate-change.html>

The proponents later updated this assessment to include the carbon sinks impact of the TLAA⁹. They used a maximum length of 28.6 km and an area of approximately 10,835 ha, of which 12.6 to 31.6 ha are wetland areas. The proponents estimated the project would result in a total of 431 t of carbon storage loss from the wetland areas (1,581 t CO₂ released if all carbon is oxidized).

ECCC Views

ECCC is of the opinion that the Proponents' assumptions and estimate of impact on carbon sinks are reasonable. While the proponents did not use consistent land classes, areas, and data across both the carbon sinks and land-use change calculations, the site-specific information used in the carbon sinks assessment is more accurate and should be applied to the direct land-use change emissions calculations.

2.3 Upstream Assessment

Upstream emissions include the domestic and non-domestic emissions associated with all stages of production, from the point of extracting the resources up to, but not including, the activities within the scope of the project under review. For an LNG project, they include emissions from the extraction and processing of the natural gas up to, but not including, the LNG facility, as well as the emissions from the transmission of natural gas up to the LNG facility.

The SACC describes the circumstances that require an upstream GHG assessment. In this case, the proponents were asked to complete an upstream GHG assessment because the project's anticipated upstream emissions were estimated to exceed the 500 kt CO₂ eq per year threshold in the SACC.

The upstream GHG assessment involves a two-part methodology: Part A is a quantitative estimate of the GHG emissions released as a result of upstream production, and Part B is a discussion of whether this upstream production and the associated emissions could still occur in the absence of the project, and the potential impact the emissions could have on Canadian and global GHG emissions. This discussion ties into Section 5.1.3 of the SACC regarding impact on global GHG emissions.

For the Ksi Lisims project, the Part A quantitative estimate included GHG emissions expected to be released as a result of upstream production, processing, and transmission of natural gas needed for the project. Indirect upstream emissions, including land-use changes, exploratory

⁹ See section F.9.4 of [Updated Transmission Line Assessment Area Supplemental Information](#).

drilling, manufacturing of equipment and material, and construction of infrastructure on site, were not included in the estimates. The annual upstream GHG emissions for the first year of operation in 2028 were estimated as 4,141 kt CO₂ eq., decreasing gradually to 3,245 kt CO₂ eq. in 2035 and remaining constant for the remainder of the project's operation phase.

Part B of the assessment is a discussion from the proponents focused on the forecasts for natural gas production and LNG production for the Canadian energy system, as presented in the Canada's Energy Future Report 2023 developed by the Canada Energy Regulator (CER)¹⁰. This report from the CER provides the three scenarios which include projections for natural gas and LNG production. The proponents have stated the anticipated upstream incrementality under each scenario:

- 1) **Global Net-zero Scenario:** Assumes that Canada achieves net-zero emissions by 2050, and the rest of the world reduces emissions enough to limit global warming to 1.5 °C. International assumptions come from the International Energy Agency (IEA)'s 2022 World Economic Outlook (WEO) Net Zero Emissions Scenario. Canadian natural gas production peaks in 2023 and starts to steadily fall starting in 2026. Exports of natural gas ramp up in 2025/2026 to peak in 2029 and remain level until starting to fall in 2045 due to lower global LNG demand. In this scenario, the proponents state that the upstream production could be entirely incremental, not incremental at all, or a mixture of incremental and current production of Canadian supply.
- 2) **Canada Net-zero Scenario:** Assumes that Canada achieves net-zero emissions by 2050, but the rest of the world moves more slowly to reduce GHG emissions. International assumptions come from the IEA's 2022 WEO Announced Pledges Scenario (assumes all announced climate commitments and policies are successfully implemented but no further action is taken). Natural gas production rises in 2030 to 17.7 Bcf/day and LNG exports are higher than in the Global Net-zero Scenario. Natural gas exports are expected to grow until 2030 and remain flat, with production falling in 2050. According to the CER, natural gas production averaged 17.9 Bcf/day in 2023, surpassing their modeled estimate for 2030¹¹. While the incrementality of the project's emissions will depend on the rate of retirement of existing natural gas projects, the proponents state that the

¹⁰ [CER – Canada's Energy Future 2023 report \(cer-rec.gc.ca\)](https://cer-rec.gc.ca).

¹¹ [CER – Market Snapshot: Canadian natural gas production hits a record high in 2023, and industrial gas use continues to increase \(cer-rec.gc.ca\)](https://cer-rec.gc.ca)

upstream production could be entirely incremental, not incremental at all, or a mixture of incremental and current production of Canadian supply.

- 3) **Current Measures Scenario:** Federal, provincial, and territorial climate policies that are in place as of March 2023 are modelled. This assumes no further action on climate change and does not require Canada to reach net zero by 2050¹². International assumptions come from a range of institutions, academia, industry, private forecasters, and other relevant energy analysis. Natural gas production rises to 21.5 Bcf/day in 2050 and LNG exports are higher than in the other two scenarios, with natural gas exports peaking in 2034 and staying at that level to 2050. The proponents state that the project's emissions under this scenario are likely incremental to Canada (in order to meet growth in demand, due to lower climate ambition in Canada and internationally).

Under either the Global Net-zero and Canada Net-zero scenarios, the proponents note a higher level of uncertainty in whether upstream production may be entirely incremental, not incremental at all, or a mixture of incremental and current production of Canadian supply. The proponents note that there are numerous other reasonable pathways to global net-zero where upstream production may not be fully incremental, such as displacement of additional net-pipeline exports or displacement of domestic demand. Although there are numerous paths that Canada could take to reach net zero, since 2022, the IEA's WEO reports have shown natural gas demand peaking by 2030 and remaining flat afterwards, even in their Stated Policies (STEPS) scenario which assumes no further climate action.

ECCC Views

Even with these projections, it is difficult to say with certainty if the project's upstream emissions will be internationally incremental, as this will largely depend on who is buying the LNG and where it will be used, what fuel sources LNG replaces, and the pace of international transitions towards net-zero. The argument that there will be higher global emissions if LNG is sourced from other projects with higher upstream emission intensities does not consider the reality that an approved project in Canada will not prevent approvals or production elsewhere in the world, potentially leading to a global over supply of LNG or locking in a higher emissions pathway. It cannot be assumed that LNG will displace higher emitting sources. It is possible that an oversupply of LNG could drive down international prices, making LNG more cost

¹² This scenario does not model relevant federal climate announcements including Clean Energy Regulations, Oil and Gas Emissions Cap, and a 75% reduction in oil and gas sector methane emissions relative to 2012 levels by 2030.

competitive with renewables or other cleaner options, perhaps displacing renewables rather than higher emitting fuels and slowing down the energy transition. Further, LNG purchase decisions are predominantly made by importing countries based on price rather than emissions intensity.

Based on ECCC's analysis of the CER report, it is likely that the emissions associated with the Ksi Lisims project will be incremental in Canada for all scenarios. For example, the project was not considered in the CER's LNG exports forecast for the Canada Net-zero scenario and the model did not project a need for further LNG production, indicating that the upstream emissions are completely incremental in this scenario. Note that the CER forecasts are based on assumptions at the time of development, hence if the project is approved, it could be included in CER's next forecast.

The proponents also cited a number of other projections, which have been considered in ECCC's analysis:

- The 2022 Gas Exporting Countries Forum (GECF) Global Gas Outlook: ECCC is of the opinion that the findings in this report should not be taken as reflective of Canadian or international climate ambition, as its arguments that striving for net-zero by 2050 would come at a negative cost to economic and social well-being have been challenged by the Canadian Climate Institute¹³, and ECCC address with the counterargument.
- The 2023 US EIA's Annual Energy Outlook (AEO): This report does not align with the proponents' statement that US EIA sees US LNG exports potentially doubling by 2050. Furthermore, relying on the interchangeability of US and Canadian natural gas in export markets is an unrealistic assumption given the high volume of already approved LNG capacity in the US.¹⁴ In this scenario, it is likely that the project's upstream emissions could be partly or entirely internationally incremental.
- Shell 2023 LNG Outlook and 2021 Shell Report: The 2021 report was not included in the proponents' list of references and could not be corroborated. Shell's more recent 2024 LNG Outlook projects LNG demand to peak in most Asian markets in the 2040s, however most of this demand is met by domestic LNG production rather than imports, due to an increasing concern globally around energy security. Furthermore, projected imports to Asian markets come from American supply, most of which is already under

¹³ [Canadian Climate Institute's Report, Damage Control: Reducing the Costs of Climate Impacts in Canada](#)

¹⁴ [Status of U.S. LNG Export Permits and Associated Greenhouse Gas Emissions](#)

development. In this scenario, further Canadian LNG could generate international incremental emissions or not, depending on the rate of American LNG development.

- IEA’s 2022 World Economic Outlook (WEO): The proponents state that “all IEA scenarios show natural gas maintaining some role in the global energy mix.” While this is true, IEA has revised the projected LNG demand for 2040 in their STEPS scenario (their most conservative scenario in terms of climate action) by 20%, suggesting that planned capacity is sufficient to meet LNG demand in 2040, even if no further climate action is taken. In IEA scenarios it is likely that the project’s upstream emissions would be entirely internationally incremental.

Overall, ECCC agrees with the proponents’ conclusion that upstream GHG emissions could be fully or partially incremental domestically, but does not agree that global GHG emissions would not be incremental globally. This is because ECCC does not agree with the proponents’ claim that incremental upstream GHG emissions within Canada would necessarily achieve a net GHG reduction globally by minimizing reliance on production from higher emitting jurisdictions.

3. MEASURES TO MITIGATE GHG EMISSIONS

3.1 Proponents’ planned mitigation measures

The proponents provided a Best Available Technologies/Best Environmental Practices (BAT/BEP) Determination, following the process described in the SACC and the draft Technical Guide. The proponents identified and assessed the following key mitigation measures, amongst others: fuel selection, on-site power generation technologies, acid gas removal technologies, and carbon capture, utilization and storage (CCUS). After assessing the technologies, the proponents identified two feasible combinations of BAT/BEP:

- 1) **Combination 1:** represents a realistic uptake of technologies and practices available at the start of construction and operation.
- 2) **Combination 2:** represents a more ambitious approach with higher GHG reduction potential, but lower technical feasibility.

Table 3 summarizes the key technologies selected for each combination. The main differences between the two combinations are underlined.

Table 3. Key Best Available Technologies Considered by the Proponents

Phase	Combination 1	Combination 2
Construction	• Renewable diesel • Gasoline fuel • <u>Marine diesel fuel</u> • Dual fuel diesel/LNG fuel	• Renewable diesel • Gasoline fuel • Dual fuel diesel/LNG fuel
Operation	• Connection to BC electricity grid • <u>Temporary gas-fired barges if needed</u> • Diesel generators • Thermal oxidizer with natural gas combustion • Fugitive/leak reduction technologies • Flaring • Dual fuel boil-off gas and marine fuel or LNG	• Connection to BC electricity grid • Diesel generators • Thermal oxidizer with natural gas combustion • Fugitive/leak reduction technologies • Flaring • Dual fuel boil-off gas and marine fuel or LNG • <u>Boil-off gas</u> • <u>Electricity (battery) with fossil fuel back-up</u>
Decommissioning	• Renewable diesel • <u>Gasoline fuel</u> • Electricity (battery) • Dual fuel diesel/LNG fuel	• Renewable diesel • <u>Electricity (battery)</u> • Dual fuel diesel/LNG fuel

CCUS was not included in either of the combinations as the proponents indicated it is not technically or economically feasible due to the lack of suitable sequestration locations near the project site.

Meanwhile, the environmental practices identified for both combinations are generally the same, including anti-idling, biomass burning, recovery of merchantable timber, regular maintenance of equipment (e.g., on-land and marine construction equipment, temporary power barges if needed, back-up diesel generators), leak detection monitoring, electricity and fuel consumption monitoring, and efficiency measures.

The proponents selected to move forward with Combination 1, mainly due to technology readiness for the implementation at the start of each phase, and uncertainty with regard to timing of availability of some mitigation measures in Combination 2.

ECCC Views

ECCC recognizes that the proponents' mitigation measure of using BC Hydro's grid electricity provides significant reduction of the project's potential GHG emissions. As noted above, if

connection to the grid is not in place for the first operating year, this increases the net emissions from 253 kt CO₂ eq. / year to 1,868 kt CO₂ eq. / year. A timely connection to the grid would avoid the need for the Alternative Case.

The SACC requires that the proponents' BAT/BEP Determination consider mitigation measures for all emissions from the net GHG equation, which includes the total GHG emissions generated by activities that are within the defined scope of the project. Since emissions associated with the TLAA were not included in the proponents' estimate of total GHG emissions, it is unclear whether the BAT/BEP Determination considered options related to the electricity transmission line. For example, the proponents' analysis could benefit from consideration of BAT/BEP for submarine construction activities for the transmission line. By considering the project's full GHG emissions scope, the proponents may be able to identify a greater overall GHG reduction potential in their BAT/BEP combinations, helping the proponents to further reduce emissions.

ECCC suggests that the above be considered in a future iteration of the BAT/BEP Determination.

3.2 Best-in-Class

The proponents stated that Ksi Lisims will be the lowest emission intensity LNG facility globally. This is based on the assumption that the project is connected to BC's renewable grid. As a part of the comparison to best-in-class global projects, the proponents compared the project's GHG emission intensity with two LNG facilities: LNG Canada in BC and Gorgon LNG in Australia. Table 4 below summarizes the proponents' comparison between these three facilities.

Table 4. Proponents' comparison with other LNG facilities

	Ksi Lisims LNG	Gorgon LNG	LNG Canada
Start of Operation (year)	2027 expected	2015	2025 expected for Phase 1 2029 expected for Phase 2
Capacity (MTPA LNG)	12	15	26
Key Differentiating Technologies	BC Hydro electricity with secondary natural gas turbines	Natural gas turbines with carbon capture	Natural gas turbines with secondary BC Hydro grid electricity
GHG Emission Intensity – excludes marine emissions	0.018 (Base Case) 0.153	0.27	0.152

(t CO ₂ eq. / t LNG)	(Alternative Case)		
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ECCC Views

The proponents' submission generally followed the draft Best-in-Class guidance¹⁵. However, the proponents' comparison against Gorgon LNG and LNG Canada did not provide reasoning as to why those two projects were a suitable comparison. ECCC is aware of other projects such as Woodfibre LNG and Cedar LNG that may have lower emissions intensities than the selected comparison projects, however ECCC supports the proponents' use of comparison projects that are already operational or nearing completion. Furthermore, the proponents did not explain why it chose to exclude marine emissions from its emission intensity calculations. Marine emissions within the scope of the project should have been included, as per the SACC and draft Best-in-Class Guidance. When considering the project's full set of emissions, the emission intensity would be 0.021 t CO₂ eq. / t LNG under the Base Case with the connection to BC Hydro's grid, and 0.156 t CO₂ eq. / t LNG under the Alternative Case using power barges. The proponents acknowledged these values in their net-zero plan, but did not apply them toward their best-in-class analysis.

The proponents identified the use of BC's renewable grid electricity as the project's key advantage regarding GHG emission intensity, compared with the other two projects primarily using natural gas combustion. However, it is possible that Ksi Lisims will also need to rely on natural gas combustion for part of its operation phase if the connection to the renewable BC Hydro grid is unavailable. This would substantially impact the project's annual operations emissions, increasing the emission intensity above what is anticipated for LNG Canada, as shown in Table 4. This demonstrates that the project's connection to BC Hydro is essential to its ability to achieve best-in-class emissions performance.

ECCC is of the view that the project is likely to be best-in-class compared to currently operating LNG facilities, if it can connect to BC's electricity grid by the start of operations. However, the project would not be best-in-class if on-site power generation is required, since there are several international facilities with lower emission intensities. In line with the proponents' commitment to continuous improvement of emissions performance over the lifetime of the project, ECCC

¹⁵ <https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/oil-gas-emissions-cap/best-class-draft-guidance.html>

recommends that the proponents continue to consider best-in-class emissions performance as part of the net-zero plan review process.

3.3 Proponents' Net-Zero Plan

The proponents provided a plan outlining how the project can achieve net-zero emissions. This plan was developed to respond to both provincial and federal net-zero planning targets:

- B.C.'s New Energy Action Framework requiring LNG facilities to pass an emissions test with a credible plan to be net zero by 2030¹⁶;
- Canada's SACC requirement for a credible plan to achieve net-zero emissions by 2050, based on the project's net GHG emissions as defined through the SACC.

The scope of the proponents' net-zero plan between 2030 and 2050 aligns with BC's requirements, and includes venting, flaring, fugitives, industrial processes, and emissions associated with purchase of electricity. In 2050, the scope of the plan expands to include marine emissions, as required to respond to the federal requirements in the SACC.

Electrification of the project is key to the net-zero plan. The proponents recognize that the foundation of their plan is electric drive compression technology, the use of which depends on the ability of BC Hydro to deliver sufficient electricity to site. As such, the proponents plan to be net-zero ready for 2030, and are confident that BC Hydro will be in a position to provide the required transmission infrastructure to electrify the project by that time, based on recent BC Hydro and BC government activities¹⁷. BC Hydro has not yet made a commitment to the proponents.

Additional mitigation measures are discussed in the net-zero plan, including:

- Possible future implementation of CCUS upstream of the project to reduce direct emissions from acid gas removal and thermal oxidation within the project scope;
- Implementation of a leak detection and repair program to reduce fugitive emissions;
- Waste heat recovery systems;

¹⁶ <https://news.gov.bc.ca/releases/2023PREM0018-000326>

¹⁷ These activities include the establishment of a BC Hydro task force to accelerate electrification announced through BC's New Energy Action Framework, BC Hydro's announcement to procure 3,000 GWh per year of clean or renewable energy with the in-service dates designed for 2028, and the Mandate Letter from Premier Eby to Minister of Energy, Mines and Low Carbon Innovation including direction to improve timing and transparency of permitting processes to support sustainable economic development.

- Offset credits.

The net-zero plan relies on offset credits to address any residual emissions that are not addressed by BAT/BEP. The proponents intend to prioritize the use of offset credits from participating Indigenous nations that align with the appropriate requirements under BC's proposed Net Zero New Industry Intentions Paper (NZNIIP) and BC Offset Protocols. The proponents have undertaken a preliminary investigation of potential nature-based solutions offsets with the Nisga'a Nation and they are conducting a feasibility study of forestry offset potential among the Nation's over 200,000 ha of Treaty Land.

The proponents' net-zero plan presents three possible cases for net emissions, each incorporating Combination 1 of the BAT/BAP Determination. For each scenario, the number of offset credits required on an annual basis is presented:

- 1) **Base Case:** assumes sufficient electricity is available at the start of operations.
 - o Offset credits requirements range from 212,798 to 249,213 credits annually.
- 2) **Alternative Case:** assumes the use of temporary power barges until grid connection is established. Although this increases annual operations emissions substantially pre-grid connection (including beyond 2030), the proponents have chosen not to offset emissions from on-site power generation using power barges.
 - o Offset credit requirements are identical to the Base Case, ranging from 212,798 to 249,213 credits annually. Net-zero is not achieved in 2030.
- 3) **Base Case Under Additional Considerations and Future Policy:** assumes 100% renewable electricity system by 2030 and sufficient advancements in technologies, policies, and economics to utilize CCUS upstream, therefore reducing the project's direct GHG emissions from 2040 onwards.
 - o Offset credits requirements range from 37,575 to 248,831 credits annually.

The proponents will establish a committee of relevant stakeholders to review the net-zero plan every 5 years. Progress reports on key metrics of the plan are intended to be provided annually. The proponents committed to continually evaluate and assess new technologies as they become feasible for use at the facility. As stated by the proponents, defensible, rigorous, and effective measures to reduce GHG emissions and meet net-zero commitments from the project are critical for BC to meet targets for greenhouse gas reduction. These emission reductions would help Canada meet its climate goals, in parallel.

ECCC Views

The draft Technical Guide Related to the SACC describes the principles of the net-zero plan, which include prioritizing reductions from direct GHG emissions and acquired energy GHG emissions and using offsets as a last option to mitigate residual GHG emissions. ECCC recognizes that the proponents' net-zero plan is to use offset credits to mitigate the project's residual GHG emissions to achieve net-zero emissions by 2030 (in all cases except for the Alternative Case). Of note, unless a mechanism is set to enable the use of foreign offset credits, offset credits used to meet net-zero targets will have to be sourced from a project registered in a Canadian compliance offset system recognized by British Columbia's Output-Based Pricing System. It is currently difficult to predict the number of credits that will be available for sale from Canadian compliance offset systems in 2030 and beyond since that depends on many unknown factors including what offset protocols will be available in compliance programs in the future, what GHG reduction activities they will include and what the uptake is going to be. Therefore, it is challenging for ECCC to comment on whether it is reasonable to expect the proponents to obtain up to 249,213 offset credits every year starting in 2030.

ECCC notes that the expected price of offset credits is not mentioned by the proponents. Carbon pricing will reach \$170/t CO₂ by 2030, which will impact prices for offset credits that the proponents will require to achieve net-zero emissions by 2030. Based on the estimated production volumes, the facility would be regulated under the proposed Oil and Gas Emissions Cap Regulations, for which a Regulatory Framework discussion paper¹⁸ was published in January 2024. While draft regulations are not yet available, they could potentially impact compliance costs under the three cases for net-zero emissions. ECCC recommends that the proponents consider the risk and uncertainty around the supply and demand of offsets credits in any subsequent versions of its plan. This includes the consideration of offsets under British Columbia's Output-Based Pricing System's expiring after 3 years, usage being limited to 30% for the 2026-2030 period, and the compliance demand dependent on the number of LNG facilities that become operational.

ECCC notes that the proponents' net-zero plan extends to the year 2057. As such, the decommissioning phase has not been considered in the plan, which is expected to start in 2058. Therefore, it is likely that the proponents will require an even greater number of offset credits in

¹⁸ [Regulatory Framework for an Oil and Gas Sector GHG Emissions Cap](#)

order to maintain alignment with BC's new energy action framework. ECCC encourages the proponents to include the project's decommissioning phase in subsequent versions of the plan.

ECCC acknowledges that the proponents have made a number of commitments related to their net-zero plan. These include, but are not limited to:

- The project being net-zero ready with the ability to accept BC Hydro electricity at commissioning;
- If connection to the electricity grid is not ready in time for commissioning:
 - Working with the BC government, stakeholders, and rightsholders to find viable solutions to address the temporary increase in emissions until connection is completed;
 - Removing temporary gas turbines once the necessary transmission infrastructure is provided by BC Hydro;
- Developing a strong GHG management framework and a carbon offset and credit utilization program prioritizing Indigenous nation-led carbon offsets;
- Continuous improvement to minimize facility emissions throughout the life of the project through:
 - Continuous evaluation and assessment of emissions reductions and new technologies;
 - Continually updating the BAT/BEP assessment and implementing emission reduction opportunities as they become feasible over time;
- Establishing, reviewing, and monitoring emissions targets in consultation with stakeholders.

ECCC recommends that the proponents put in place a process to ensure that these important commitments are tracked and implemented into the future.

Overall, ECCC concludes that the proponents' plan generally meets the requirements of the SACC's credible plan that describes how the project will achieve net-zero emissions by 2050. However, ECCC notes that the proponents' current net-zero plan only achieves net-zero emissions in 2030 if the project is supplied with sufficient BC renewable grid electricity by that time (i.e. under the Base Case). In their Alternative Case, the proponents indicated that it is premature to address the impacts of the NZNIIP on the net-zero plan, since that document is currently in draft form.

4. CANADA'S GHG EMISSIONS PROJECTIONS

Canada's emissions reduction target under the Paris Agreement is 40-45% below 2005 levels by 2030. This equates to a national target of 439 megatonnes of CO₂ eq. under a 40% reduction.

The total LNG capacity of all proposed LNG projects in Canada exceed what is currently forecasted by the CER for 2030. As a result, if all proposed projects are built, in the absence of any other changes, Canadian emissions would be higher than projected. If the upstream emissions associated with the project are fully incremental, they would hinder Canada from meeting the climate commitments.

However, there are several factors that will likely reduce the GHG footprint of future LNG Projects in BC: the trend toward full electrification of project operations, the mandated emissions intensity for the LNG sector under BC's Greenhouse Gas Industrial Reporting and Control Act¹⁹, as well as the new energy action framework for all proposed LNG facilities to have a credible plan to be net-zero by 2030. Federal measures such as Canada's Emissions Reduction Plan under the Net-Zero Emissions Accountability Act, the proposed oil and gas emissions cap, the Clean Fuel Regulations, and International Maritime Organization GHG strategies may also contribute to emissions reductions.

The project's net GHG emissions are also expected to hinder Canada's climate change commitments to some degree. This is more pronounced in the case where power barges are needed to produce on-site power, especially considering that the proponents do not intend to offset these emissions. Since uncertainty remains regarding the connection date to BC Hydro's renewable grid, it is difficult to definitively conclude on the project's expected impact on Canada's emissions targets.

In terms of the longer-term commitment from the Government of Canada to reach net-zero emissions by 2050, any future LNG production that will come online is anticipated to continue to be operational in 2050. The operators of the forecasted LNG production, as well as the operators of the upstream natural gas production and transportation to sustain LNG production, would have to implement plans to reach net-zero by 2050 to remain consistent with the commitment. The proponents have stated that the project will be "net-zero ready by 2030", to align with the new energy action framework of the province of British Columbia. Although it is still uncertain whether net-zero by 2030 will be achieved, it is expected that the project will be able to connect

¹⁹ [Greenhouse Gas Industrial Reporting and Control Act](#)

to BC's grid prior to 2050. The proponents' net-zero plan indicates a commitment and willingness to achieve net-zero emissions in line with Canada's 2050 target. Incremental upstream emissions may also decline in the approach to 2050 due to climate regulations and policy.

5. CONCLUSION

The maximum annual sum of direct and acquired energy GHG emissions associated with the project are estimated by the proponent to be between 59 kt CO₂ eq. / year and 212 kt CO₂ eq. / year during construction, and between 253 kt CO₂ eq. / year and 1,868 kt CO₂ eq. / year during operations. The ranges in the emissions estimates are due to the uncertainty around the timing of the project's connection to BC Hydro's renewable energy electricity grid. The project's upstream GHG emissions are estimated to be between 3,245 and 4,141 kt CO₂ eq. / year.

The proponents' intention to use BC Hydro's grid electricity provides substantial GHG emissions reductions and may offer further reductions as renewable electricity expands. Once the project is connected to BC electricity, it is likely to be one of, if not the lowest emission intensity producers of LNG globally, with an estimated emission intensity of 0.021 t CO₂ eq. / t LNG including marine emissions. However, under the Alternative Case, emission intensity would be substantially higher (0.156 t CO₂ eq. / t LNG) for the years before grid connection, and the proponents best-in-class emissions performance claims may not be realized.

The proponents also provided a plan for the project to achieve net-zero emissions by 2050 in line with the SACC's credible net-zero plan requirements and Canada's net-zero GHG emissions target for 2050. To meet BC's net-zero requirements, the proponents plan also incorporated the requirement to meet net-zero by 2030, under the Base Case only. To accomplish these goals, the plan presented in the Revised Application relies heavily on procuring offset credits. The proponents did not discuss the feasibility or availability of procuring offset credits, particularly by 2030. ECCC acknowledges that the proponents will consider other options to reach net-zero as those options become available. The proponents also indicated that the net-zero plan will be reviewed every five years to include adjustments to scenarios and new mitigation strategies, and progress reports will be provided annually on key metrics of the plan. When reviewing this plan, ECCC recommends the proponents first consider other mitigation measures to further reduce GHG emissions throughout the project's lifetime and, when offset credits are used, provide information on the availability and feasibility on the use of offset credits while ensuring that offset credits are a last option to achieve net-zero emissions.

The GHG emissions resulting from the LNG project, including the net GHG emissions and upstream GHG emissions associated with the project, would be incremental to the Government of Canada's 2030 emissions projections. If approved, the project's GHG emissions and related upstream emissions would impact Canada's ability to meet its commitments in respect of climate change. Although these conclusions are relevant under both the Base Case and Alternative Case, potential impacts are more pronounced under the Alternative Case before the project is successfully connected to BC Hydro's grid and receiving sufficient electricity to power the project.