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Examine the feasibility of electrifying a natural gas pipeline system: a case study on Enbridge's Westcoast pipeline

by

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ABSTRACT

Climate change is an evolving global issue that needs all industries to act. This research aims to examine the feasibility of reducing operational-related (Greenhouse Gas) GHG emissions at natural gas transmission pipeline through electrification, using Westcoast pipeline in BC as the case study. The research evaluated the GHG reduction potential at the pipeline's gas compressor stations under three electrification scenarios. A cost-benefit analysis was performed for each scenario and compared with baseline scenarios. All the data in the research were selected using publicly available data. The analysis suggests that electrification will significantly reduce GHG emissions at the Westcoast pipeline; however, all three scenarios would surpass baseline operational cost due to incremental electricity demand. Future uncertainties, such as changing carbon tax price, natural gas price, electricity price, and gas compressor maintenance cost, might shift the electrification project financial analysis results.

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BCF: Billion cubic feet

CACs: Criteria air pollutants

CBL: Customer baseline load

CGA: Canadian Gas Association

CH_4: Methane

CIIP: CleanBC Industrial Incentive Program

CO_2: Carbon dioxide

CO_2e: Carbon dioxide equivalent

CPS: Current policies scenario

DSM: Demand Side Management

Dth: Dekatherms

ECCC: Environmental and Climate Change Canada

EMD: Electric-motor-driven

FERC: Federal Energy Regulatory Commission

GDP: Gross domestic product

GEP: Gas Electric Partnership

GHGRP: Greenhouse Gas Reporting Program

GOBC: Government of BC

GOC: Government of Canada

GWh: Gigawatt hour

HHV: Higher Heating Value

Hp: Horsepower

IEA: International Energy Agency

IPCC: Intergovernmental Panel on Climate Change

km: kilometer

kW: kilowatt

kWh: kilowatt hour

LNG: Liquid natural gas

MOU: Memorandum of Understanding

MTBF: Mean time between failures

MTPA: Million tonnes per annum

MW: Megawatt

MWh: Megawatt hour

NIR: National inventory report

N_2O: Nitrous Oxide

OBPS: Output-Based Pricing System

O & M: Operational & maintenance

PRES: Peace Region Electricity Supply

SDS: Sustainable development scenario

Shell: Royal Dutch Shell

SPS: Stated policies scenario

tCO_2e: tonnes of carbon dioxide equivalents

TETLP: Texas Eastern Transmission Pipeline, LP

TWh: Terawatt hour

VFD: Variable frequency drive

WEO: World Energy Outlook

Chapter 1. INTRODUCTION

The urgency to address climate change and the need to meet the growing economy with additional energy demand are the dual challenges the world is facing in the next few decades. Reducing greenhouse gas (GHG) emissions might not necessarily equal sacrificing some economic benefits. New economic growth opportunities might reveal as the world moves toward a greener economy (Rubin, 2017). British Columbia (BC) successfully demonstrated that it is possible to boost the economy while reducing its GHG emissions through a sustainable economic development approach. In 2017, BC's emissions were down by 0.5% since 2007 (Government of BC, 2019); meanwhile, the gross domestic product (GDP) of the province grew by about 23% (Statistics Canada, 2020).

The oil and gas sector is at the front line of fighting the dual challenge, and many oil companies are delivering their collective goals to support the transition to the low carbon economy. The plans generally include more green energy and cleaner oil and gas. Royal Dutch Shell (Shell) slowly expands its clean energy portfolio through renewable and low carbon energy investment with about USD 200 million per year (Pockl, 2019). BP was one of the first oil majors that committed significant investment in renewable energy. BP has about 2,200 megawatt (MW) of renewable generation capacity in the United States. However, it is unpractical to cut out society's dependency on fossil fuel in a short time. The World Energy Outlook published by the International Energy Agency (IEA, 2020) indicated the world would still heavily depend on fossil fuel by 2030 and beyond despite the fast growth of renewable energy. Therefore, reducing the emissions footprints along the fossil fuel lifecycle would be another focus area for oil and gas companies. For example, Shell announced to reduce the emissions intensity of its products by approximately 30% by 2035, and 65% by 2050 (Bousso, 2020).

Last year, Enbridge published its first Resilient Energy Infrastructure Report, also called the Climate Report (Enbridge, 2019a), to respond to the dual challenges and discussed how Enbridge addresses climate-related risks and opportunities. Enbridge discussed its strategy to limit environmental impacts by investing in renewable energy and reducing operational-related emissions. Meanwhile, Enbridge is committed to set GHG emissions reduction target by the end of 2020.

1.1. Research Objective

This study aims to evaluate the concept of electrifying natural gas transmission systems using BC Westcoast natural gas transmission pipelines as a case study. Because the GHG intensity for power generation in BC is much lower than other provinces, electrifying the Westcoast pipeline may significantly reduce operational related GHG emissions and save the natural gas for use elsewhere. This research focuses on performing the quantitative analysis under different scenarios: 1) baseline scenario, 2) rapid transition scenario, 3) steady approach scenario, and 4) practical approach scenario. Based on the study results, this research provides recommendations on the feasibility of reducing GHG emissions through electrification at the natural gas transmission pipelines.

1.2. Scope 1 Emissions and Scope 2 Emissions

Scope 1 emissions are the direct GHG emissions related to company's operation (World Resource Institute, 2015). This includes stationary combustion, vented emissions, fugitive emissions and flaring. Electrifying gas compressor at the Westcoast pipeline system would significantly reduce its Scope 1 emission by eliminating the combustion sources.

Scope 2 emissions refer to indirect GHG emissions result from purchasing electricity for operational usage (World Resource Institute, 2015). Two factors will impact the scope 2 emissions, which are total power consumption and the grid emission intensity. The grid emission intensity is calculated based on the GHG emissions associated with each unit of electricity generated. Electrification will increase the power consumption at the Westcoast pipeline system, and higher Scope 2 emissions is expected.

1.3. Energy, Environment and Economic

The research incorporates three sustainable pillars into the scenario analysis: energy, environment, and economic impacts. The first pillar evaluated is the energy and how electrification approach would impact the energy consumption at the Westcoast pipeline system. The research calculates the natural gas savings and associated incremental electricity consumption under each scenario. Analyzing the GHG emissions reduction addresses the environment pillar. The research calculates the amount of GHG reductions under different electrification scenario and compared the GHG emissions reduction to the baseline scenario. The last pillar evaluated is the economic impact on electrifying the Westcoast pipeline system. This research performs the cost-benefit analysis at each scenario to facilitate the discussion on the economic impact. Additionally, the research performs sensitivity analysis to evaluate how the variables, such as carbon tax and electricity price, might impact the operational &

maintenance (O & M) cost of the Westcoast electrification project. All the costs presented in this research are in Canadian dollar unless otherwise specified.

Chapter 2. BACKGROUND

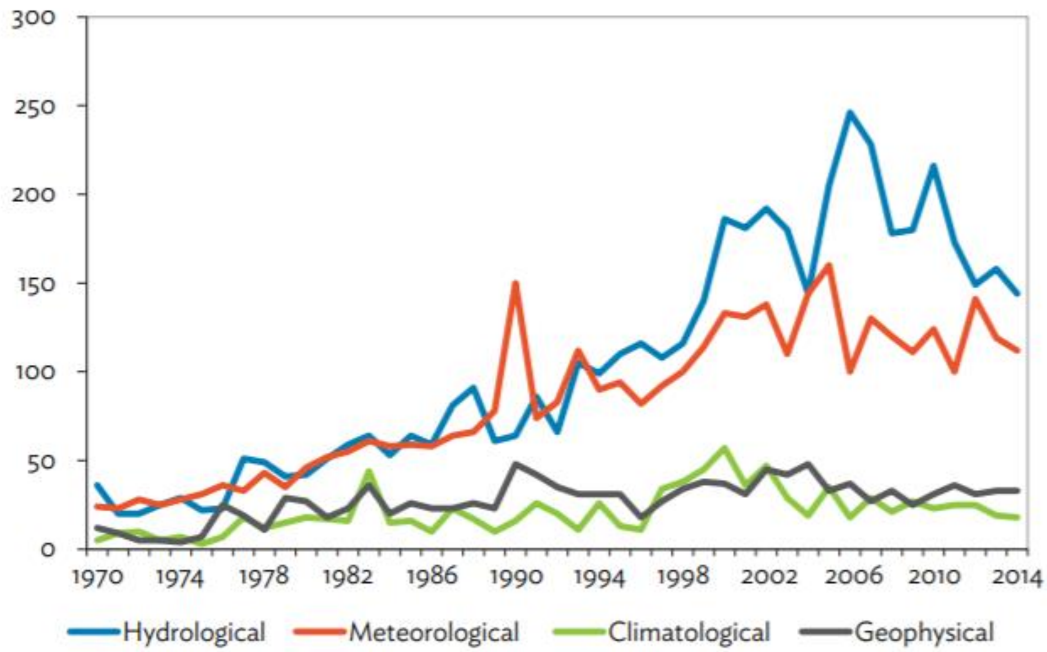
This chapter provides background information that establishes the foundation of the research. It captures the rationale for oil and gas companies reducing their operational emissions and selecting BC Westcoast pipeline for the electrification analysis. Moreover, this chapter presents an overview of Enbridge's Westcoast pipeline system and different compressors for natural gas pipeline operation.

2.1. Climate Change

Climate change is drawing more considerable attention in the past few years and is evolving into a global issue. The fifth assessment report released by The Intergovernmental Panel on Climate Change (2014) directly linked human activities to global warming. The report suggested that from 1880 to 2012 the global average temperature increased by 0.85 °C, and the average sea level rose by 19 cm because of ice melt. The report also indicated the risk of surpassing the pre-industry level temperature by the end of this century if no effective GHG reduction plan is implemented. To avoid the significant consequence of climate change, IPCC advised that global GHG emissions should be cut to half by 2030 and reach net zero by 2050.

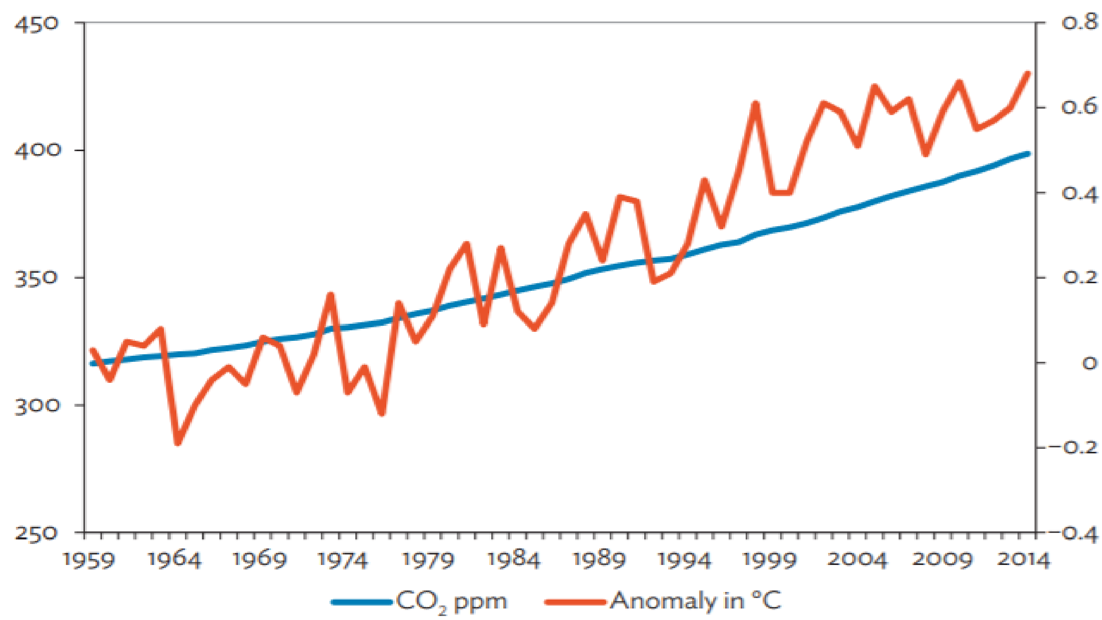
More frequent extreme natural disasters have observed in the past few decades (Thomas & Lopez, 2015). Although it remains unclear on how climate change affects individual natural disasters, scientific research suggested a strong relationship between climate change and the increasing natural disaster events (Anderson, 2006). Figure 1 represents trends indicating on the increasing frequency of natural disasters globally in the last four decades, where an upward trend is observed. Figure 2 illustrates global carbon dioxide (CO_2) concentration during the same period. The two figures suggest when global temperature is increasing, more hydrological and meteorological natural disasters are observed.

Figure 1. Global Frequency of Natural Disasters by Type (1970–2014)



Source: (Thomas & Lopez, 2015)

Figure 2. Global CO_2 Concentration in the Atmosphere (1959–2014)



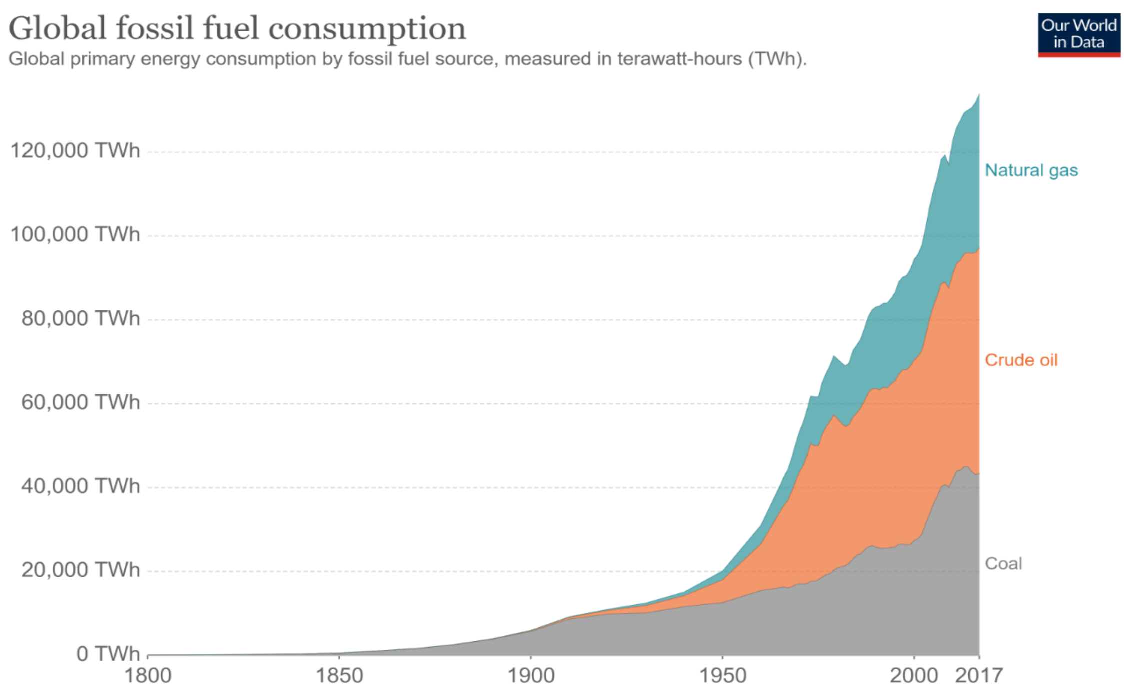
Source: (Thomas & Lopez, 2015)

Meanwhile, assets owners are increasing investment in green energy and sustainable energy development. By early 2018, the sustainable investing assets in five major global markets reached USD $30.7 trillion, a 34% increase in two years (GSI Alliance, 2018). Canada is one of the fastest-growing markets on sustainable investment, along with Japan, Australia, and New Zealand (GSI Alliance, 2018). As the investors are directing more investment into sustainable projects, it becomes another driver for oil and gas companies to switch their focus to sustainable development.

2.2. Fossil Fuel and Global Energy Outlook

Industrialization is one of the critical factors in increasing fossil fuel consumption. Figure 3 shows the global fossil fuel consumption trend from pre-industrial to 2017. Between 1970 and 2017, the global fossil fuel consumption has escalated from 53,000 terawatt hour (TWh) to about 134,000 TWh, or over 150% increase (Ritchie & Roser, 2020). Because of the high dependency on fossil fuel, it becomes the dominant source of GHG emissions. In 2017, the United States generated 6,457 million metric tonnes of GHG emissions; about 76% of those emissions are from burning fossil fuels (Energy Information Administration, 2019).

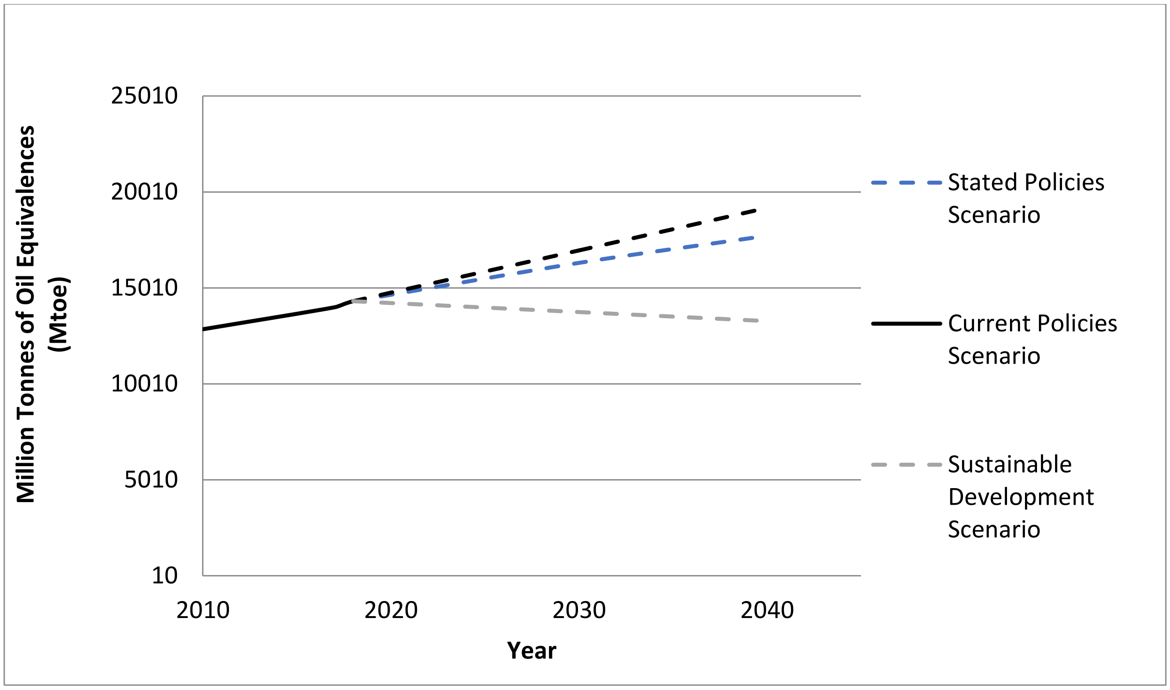
Figure 3. Global Fossil Fuel Consumption (Pre-Industrial–2017)



Source: (Ritchie & Roser, 2020)

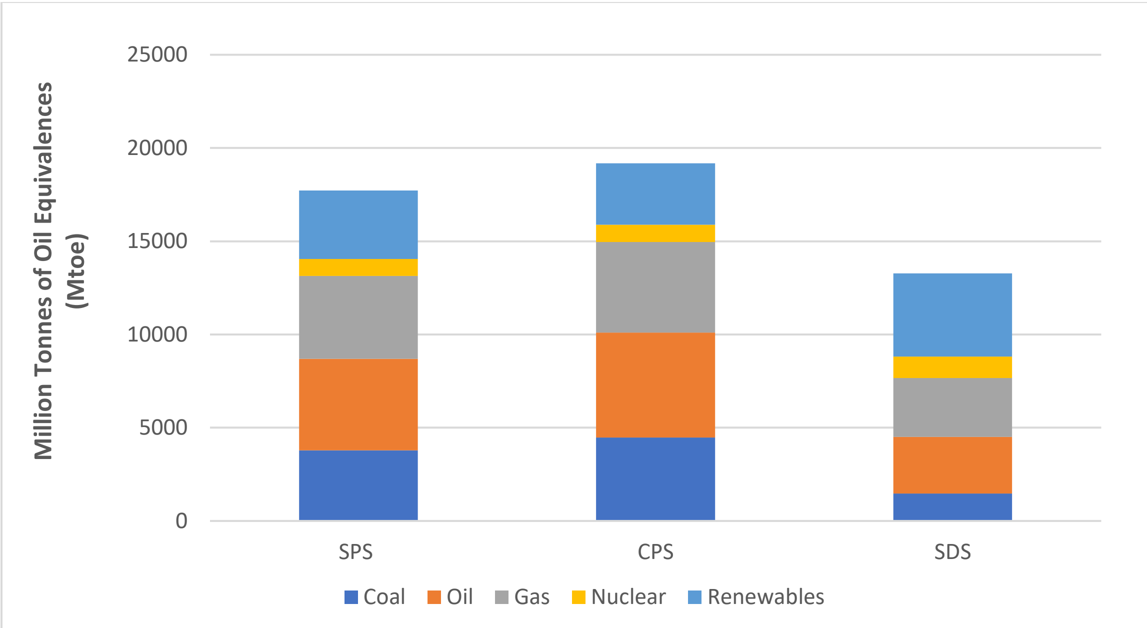
One of the barriers to completely phasing out fossil fuel is the economic challenge. A report released by the Canadian Gas Association (CGA) (ICF, 2019) evaluated the economic challenge of rapidly phase out fossil fuel. The study concluded shifting the entire Canadian economy to renewable electricity would cost from $580 billion to $1.4 trillion over 30 years, between 2020 and 2050. In the IEA's (2020) World Energy Outlook (WEO) 2019 report, it forecasted global energy demand and emissions from 2020 to 2040 under three scenarios: current policies scenario (CPS), stated policies scenario (SPS), and sustainable development scenario (SDS). Figure 4 illustrates the energy demand forecast under the three scenarios discussed in the report. As shown in the chart, energy demand would increase from present to 2040 under both SPS and CPS; however, in the SDS, the world energy demand would start dropping from 2020 to 2040, but it will still slightly higher than the demand in 2010. Figure 5 shows that fossil fuel will still occupy more than 50% of total energy demand under all three scenarios by 2040.

Figure 4. World Energy Demand Trajectory - IEA Scenarios



Source: (International Energy Agency, 2020)

Figure 5. Forecasted Global Energy Demand by 2040



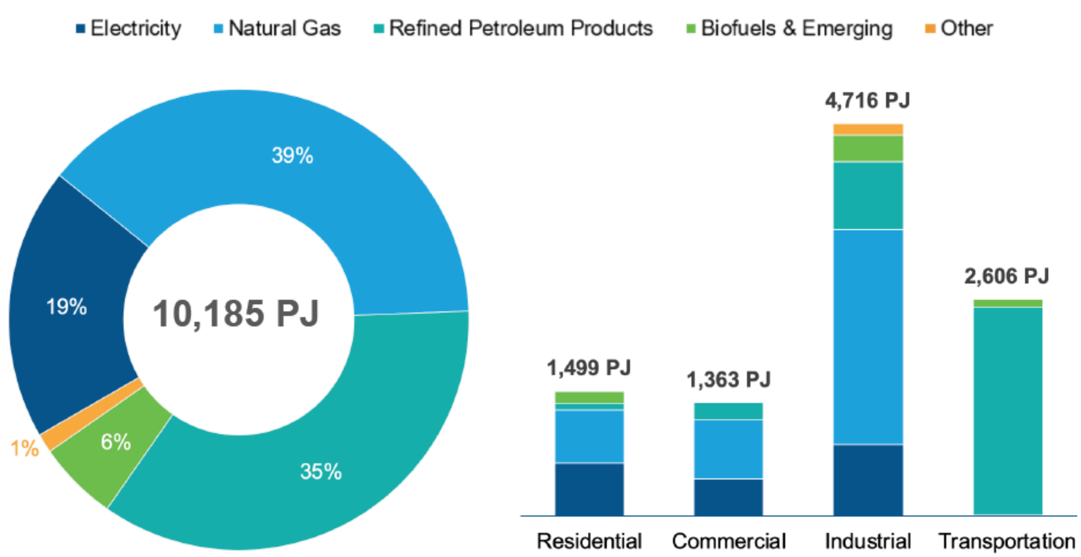
Source: (International Energy Agency, 2020)

2.3. Emissions Reduction in Canada Context

Many countries, including Canada, have made voluntary commitments in the Paris Agreement to reduce national GHG emissions and aim to limit global temperature rising to below 2 °C (United Nations Climate Change, n.d.). Under the Paris Agreement, Canada committed to reducing its annual GHG emissions to 30% below the 2005 baseline by 2030 (Government of Canada, 2020). Last year at the Conference of Parties 25 in Madrid, Canada's Environment Minister, Jonathan Wilkinson, made the statement on Canada's new 2050 net-zero plan (Hatch, 2019). This aspirational net-zero target is viewed as a historic step for Canada fighting against climate change; however, Canada remains a long way off to meet its target. To achieve the 30% GHG reduction target for Canada, it would reduce 219 million tonnes of carbon dioxide equivalents (tCO_2e) by 2030. According to the National Inventory Report (NIR) published early this year (Environment and Climate Change Canada, 2020a), Canada's 2018 national GHG emissions were 729 million tCO_2e, similar to the 2005 baseline. Therefore, Canada would need to diminish over 200 million tCO_2e between 2019 and 2030 to meet its 30% GHG reduction plan.

Canada is well-positioned in the clean electricity generation with non-emitting energy sources supplies over 80% of its electricity (Presutti, 2019). However, the electricity generation only accounts for a small portion of Canadian energy supply where less than 20% of Canadian energy requirements are supplied by electricity and more than 70% are supplied by fossil fuel (ICF, 2019). As shown in Figure 6 below, natural gas and refined petroleum products still dominate the energy market, particularly at the industrial sector and transportation section.

Figure 6. 2018 Canada Energy Consumption by Energy Type and Usage



Source: (ICF, 2019)

Advancing the development of clean electricity could play an essential role for Canada to meet the Paris Agreement. Clean electricity could slowly replace the non-essential usage of fossil fuel and attain substantial GHG reduction. In this context, electrification powered by clean energy should consider as a critical pathway in achieving emissions reduction targets in Canada.

2.4. Emission Reduction in the Canadian Oil and Gas Sector

The oil and gas industry is an essential contributor to the Canadian economy, but it is also one of the most GHG intensive industry (Environment and Climate Change Canada, 2020a). To support Canada to meet the emissions reduction goal, oil and gas sector would need to cut their emissions reduction significantly. Since last year, many Canadian oil and gas companies have announced their emissions reduction plans. For example, Cenovus announced company emissions reduction targets early this year. According to Cenovus, the reduction plan include 1) reducing emission intensity by 30% by 2030; 2) ensuring no incremental absolute emissions; 3) achieving net-zero by 2050 (Cenovus, 2020).

Enbridge disclosed in its Climate Report that the company is developing the emission reduction plan and expected to announce the target by the end of 2020 (Enbridge, 2019a).

2.5. BC Climate Policy

BC is one of the leading provinces in Canada with an ambition emission reduction target. In 2018, the province updated its emission reduction goal to 40% by 2030, 80% by 2050, using 2007 as the baseline. The Government of BC (GOBC) released its climate strategy report, where detailed outlined the provincial GHG emissions reduction roadmap (Government of BC, 2018a). The report discussed various reduction priorities for four main sectors: transportation, buildings, waste, and industry. This emissions reduction plan would potentially derive 18.9 million tCO_2e emission reduction for BC. In the industry sector, the report stated that electrification would be a critical path to reduce industrial related emissions.

Furthermore, the sustainable development commitment would support the province to be more competitive in the global energy market. The White Paper published by Clean BC in October 2018 (Clean Energy BC, 2018) assessed the economic and environmental benefits of extensive electrification to meet the province's 2030 emission reduction target. The paper concluded that extensive electrification could potentially reduce emissions up to 60% for natural gas production and up to 72% for liquid natural gas (LNG) production.

2.6. BC Carbon Tax

BC's carbon tax history can be traced back to 2008, the first jurisdiction in North America that introduced a broad-based carbon tax. The provincial carbon tax applies to approximately 70% of provincial GHG emissions (Government of BC, 2020a). BC's carbon tax regulation is more stringent than the federal Output-Based Pricing System (OBPS). BC current has \$40/tCO_2e and is expected to grow to \$50/tCO_2e by 2021 (Government of BC, 2018b), where the OBPS carbon price is at \$30/ tCO_2e and will reach \$50/tCO_2e by 2022 (Government of Canada, 2019).

2.7. BC Electrification Funding Opportunities

The government could prompt the electrification revolution in large industries through providing incentivization (Clean Energy BC, 2018). BC government is developing several funding programs that can potentially support GHG emissions reduction, including electrification projects in the provinces. Part of the carbon tax revenue will be used to subsidize those emissions reduction funding programs, including CleanBC Industrial Incentive and CleanBC Industry Fund (Government of BC, 2020a). The two programs are specifically designed for the large emitters who report operational emissions over 10,000 tCO_2e/year and regulated under the Greenhouse Gas Industrial Reporting and Control Act. The estimated GHG emissions reduction through the funding programs would be 2.5 million tCO_2e by 2030 (Government of BC, 2020b). Additionally, the federal government announced the plan to work with the BC government to promote the transition to clean fuel in the oil and gas sector. As part of this collaboration program, the federal government introduced the CleanBC Facilities Electrification Fund to support the oil and gas sector's electrification revolution.

2.8.1. CleanBC Industrial Incentive Program

CleanBC Industrial Incentive Program (CIIP) is designed to support large industries that emit 10,000 tCO_2e /year in BC, including the oil and gas sector, to reduce GHG emissions. The CIIP program provides incentives to the company that manages to demonstrate lower emissions intensity than the industry benchmark through emissions reduction initiatives. The incentive is equal to the incremental carbon tax amount above \$30/tCO_2e that the company paid in the previous year. For the company with higher emission intensity than the benchmark, it might still be eligible to apply and receive a partial incremental carbon tax refund. However, the company would need to provide a carbon emission reduction plan as part of the application requirement. The program is officially introduced in 2019 with a phase approach to give companies to adjust their operation and process to meet the benchmark.

2.8.2. CleanBC Industry Fund

Together with CCIP, the Industry Fund is another program under the CleanBC Program for Industry. The fund is designed to support innovative emissions reduction projects for large industrial operators (above 10,000 tCO_2e/year). According to BC government, in the year 2020–2021, it expects to allocate over $16.5 million through carbon tax revenue to fund industrial projects, which utilize commercially available technologies to manage company's operational emissions (B.C. Government, n.d.).

2.8.3. CleanBC Facilities Electrification Fund

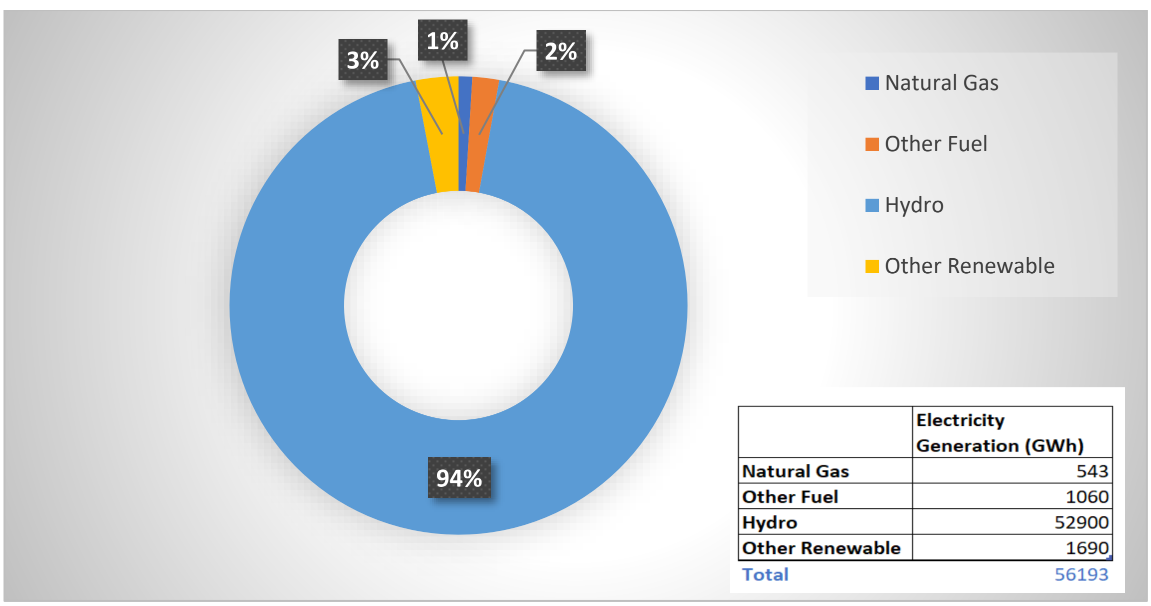
Pan-Canadian Framework on Clean Growth and Climate Change identified that one of the potential collaboration areas between the Government of Canada (GOC) and the provinces could be promoting clean energy to the oil and gas sector (Government of Canada, 2016). On August 29, 2019, GOC and the GOBC released a Memorandum of Understanding (MOU) to promote the electrification transition of the natural gas sector in BC (The Government of Canada and The Government of British Columbia, 2019). The MOU presented the joint development plan, including providing the CleanBC facilities electrification fund. The fund is part of the commitment to support and accelerate the electrification revolution in BC's natural gas sector. However, the detail of the funding program is still under development.

In summary, BC has a relatively positive policy environment supporting electrification development for the oil and gas sector. Meanwhile, the mature and stable carbon tax framework provides strong financial support through various funding opportunities to accelerate clean energy implementation.

2.8. Electricity at BC

British Columbia's abundant hydropower resources, a renewable energy form, make the province an intriguing fit for electrifying the natural gas transmission operation. As presents in Figure 7, 97% of BC's electricity was generated from renewable power in 2018 (Environment and Climate Change Canada, 2020c) and this percentage is expected to increase to approximately 100% when the Site C dam on the Peace River starts operations in 2025 (Canada Energy Regulator, 2020a). Because of the high utilization of renewable energy, the electricity grid emission factor at BC is lower than most of the provinces in Canada (Environment and Climate Change Canada, 2020c). In other words, GHG emissions results by electricity consumption in BC would be minimal.

Figure 7. BC Electricity Generation in 2018

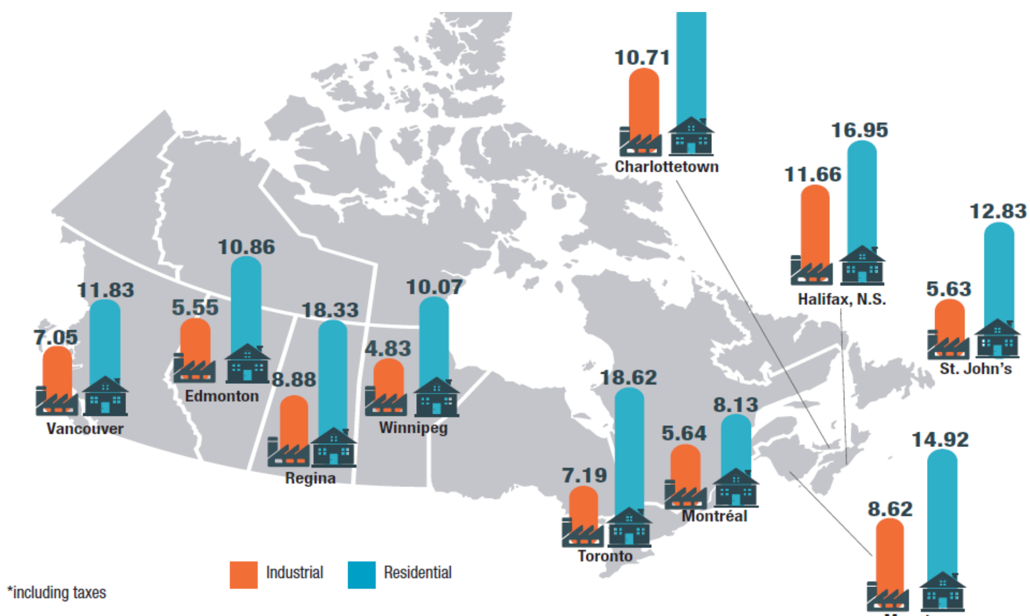


	Electricity Generation (GWh)
Natural Gas	543
Other Fuel	1060
Hydro	52900
Other Renewable	1690
Total	56193

Source: (Environment and Climate Change Canada, 2020c)

Besides the type of energy source for power generation, electricity price is another critical consideration during electrification evaluation. Figure 8 provides a high-level geographic overview of electricity prices across Canada. As seen in the map, BC has moderate electricity prices comparing with other provinces. The electricity price is higher than in Alberta, where Enbridge operates the Alliance natural gas transmission pipeline (Enbridge, 2019b). However, developing the electrification project in Alberta is not recommended as the province has much higher electricity grid GHG intensity. Alberta's electricity generation has a high dependency on coal and natural gas for power generation, where about 89% of its electricity is generated by combusting fossil fuel (Environment and Climate Change Canada, 2020c). Other provinces with lower electricity prices, such as Manitoba and Quebec, are not selected for the research as Enbridge does not have major natural gas pipeline infrastructure across those provinces.

Figure 8. Average Large Industrial and Residential Electricity Price, cents/kilowatt-hour (kWh)

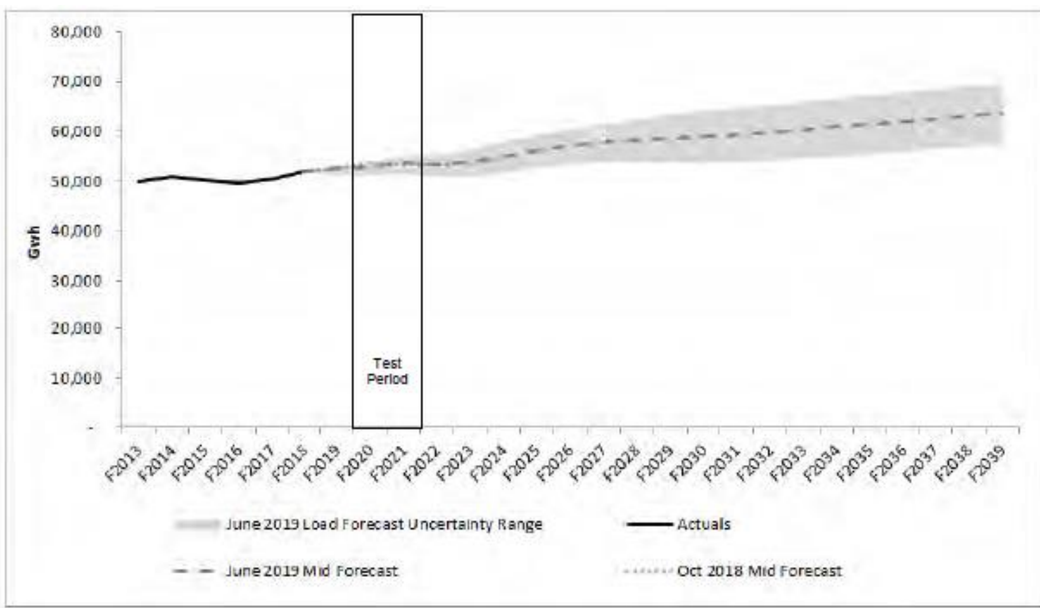


Source: (Natural Resources Canada, 2018)

There are uncertainties on BC's future electricity demand and projected electrification progress. Controversial information was presented in various government's assessment, depending on the selected electrification scenario. Based on an analysis from CleanBC, the province will need an additional 4,000 GWh over current projected demand growth of clean electricity by 2030 to support the emissions reduction goal (Government of BC, 2018a). However, according to a different report from Clean Energy BC, the renewable power generation capacity would require to increase almost 50% from existing generation capacity if the province plans to proceed with the extensive electrification approach to meet the 2030 GHG reduction target (Clean Energy BC, 2018). Under that assumption, the incremental electricity demand would be over 20,000 GWh from the 2018 electricity generation capacity (Environment and Climate Change Canada, 2020c).

BC Hydro's Load Forecast Report (BC Hydro, 2019a) provided a four-year BC power forecast from Fiscal 2020 to Fiscal 2039. This report discussed the change in energy demand for different sectors, including the large industries. BC Hydro's forecasted electricity demand growth is relatively conservation. Under the oil and gas sub-section in the large industrial sector, the forecasted energy demand would be decreased in the next few years due to cut production, delay on project expansion, and canceled new projects. The energy demand for existing facilities is expected to increase in long-term and upcoming LNG projects and increase the province's power demand. BC Hydro's 20-year load forecast expected 1% annual growth; a forecast chart could be found below in Figure 9 with uncertainty range included. Under the 2019 high forecast scenario, BC Hydro adjusted its 2027 forecast load by 20 MW to reflect the LNG development in Groundbirch area (BC Hydro, 2020a). The forecast included the natural gas sector electrification opportunities identified in the 2019 MOC, which were Bear Mountain to Dawson Creek Voltage Conversion project and North Montney Power Supply project. Although Petronas Canada released its plan to electrify its operations in Northeast BC, BC Hydro's forecast did not consider the potential impact on Petronas Canada's electrification project.

Figure 9. BC Hydro 20-year power forecast with uncertainty range



Source: (BC Hydro, 2019a)

The BC Hydro's Load Forecast Report acknowledged that many uncertainties existed in developing the long-term energy demand forecast. It is unclear that the existing development plan of the power generation infrastructures would align with the GOBC's electrification plan. In other words, whether planned new power projects could meet the growing power demand keeps up with the province's electrification speed. BC Hydro's long-term asset planning did not reference the province's electrification plans. Additionally, the Demand Side Management (DSM) program appeared to be one of the significant power-saving streams in BC Hydro's forecast. BC Hydro expected to offload approximately 3,300 GWh/year through DSM between F2021 and F2031 through upgrading codes and standards and optimizing systems. In 2019, BC Hydro reported 836 GWh saving through DSM program, only one-quarter of the forecasted saving by F2031. There is no detailed information being released to support how BC hydro would achieve the 3,300 GWh/year target.

The GOBC is proceeding with its Phase 2 Comprehensive Review with BC Hydro. The study would support to address the question of how BC Hydro could strategically support the electrification transition and meet the increased energy demand.

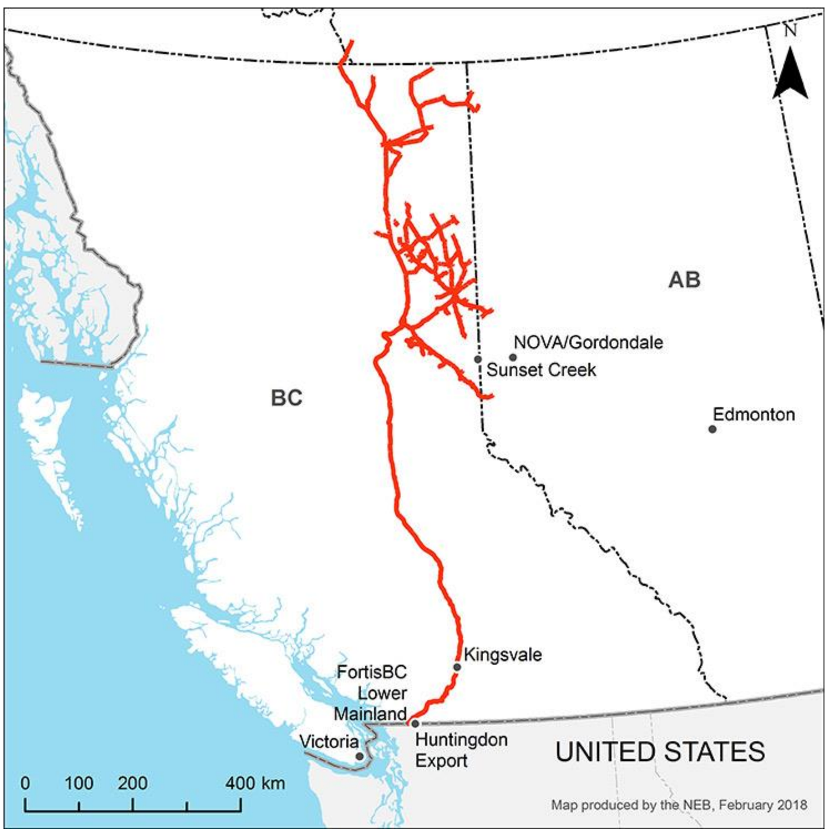
Meanwhile, BC Hydro is working to upgrade its transmission system to better integration existing power lines. New projects are under development to boost electricity supply capacity to meet the growing electricity demand. Site C project and the Peace Region Electricity Supply (PRES) projects will support the province's plan on electrification. In April 2019, the federal government announced its financial support plan on the PRES project. The federal government would fund up to 83.6 million dollars with the expected total project cost of 289 million dollars through the Investing in Canada Plan (Justin Trudeau, Prime Minister of Canada, 2019).

Therefore, the near zero-emission electricity and moderate electricity price make the province a leading candidate when Enbridge evaluates the opportunity of electrifying its natural gas transmission operations. The uncertainty remains whether BC Hydro's planned electricity capacity growth would meet BC's future incremental electricity demand.

2.9. Westcoast Pipeline System

Westcoast pipeline is among the largest natural gas transmission pipeline systems in British Columbia, where the route map is shown in Figure 10. The pipeline system was built in 1957, with a total distance of 2,858 kilometers (km). Westcoast transports approximately 55% of the natural gas produced in the province with peak daily capacity at 2.9 Billion Cubic Feet (BCF)/d (Enbridge, 2019b).

Figure 10. Enbridge Westcoast Pipeline Route Map



Source: (Canada Energy Regulator, 2020b)

Currently, the pipeline operates with natural gas-driven compressors. The compressors are the primary source of GHG emissions at the Westcoast, emitted about 1.3 million tCO_2e/year

(Greenhouse Gas Reporting Program, 2020), which is about 2.5% of total GHG emissions of BC energy sector (Government of BC, 2019).

2.10. Compressor Comparison

Since the early development stage, gas compressors are playing a significant role in the oil and gas industry (Bahadori, 2014). The broad range of sizing selection enables the gas compressors to meet different gas operations. Additionally, readily available natural gas provides reliable energy for gas compressor operation. The larger electric motor started becoming available in the late 1990s, which made it feasible to install the electric-motor-driven (EMD) compressor for large gas compression operation. A report prepared by a compressor manufacturer, TMEIC, (Blaiklock, Verma, & Bondy, 2013) compared the gas compressor and EMD compressor, some key findings in that report is presented in this section.

2.10.1. Gas Turbine Driven Compressor

Reciprocating compressors and centrifugal compressors are two common natural gas operating compressors in the oil and gas sector (United States Environmental Protection Agency, 2014). In general, the reciprocating compressor has higher efficiency, wider pressure range, and less sensitive to gas condition (Bahadori, 2014). On the other hand, the centrifugal compressor's advantages include lower maintenance cost, potentially longer run time and lower operator dependency. Other compressors types such as rotary compressor and thermal compressors are not found in Enbridge's gas operation; therefore, they are not discussed here.

The efficiency of the gas turbine ranges from 30% to 45%, depending on compressor types and models. The energy loss at gas compressors is mainly through the flue gas, where 50% or more of the energy traps in the flue gas and discharges to the atmosphere (Cleveland, 2017).

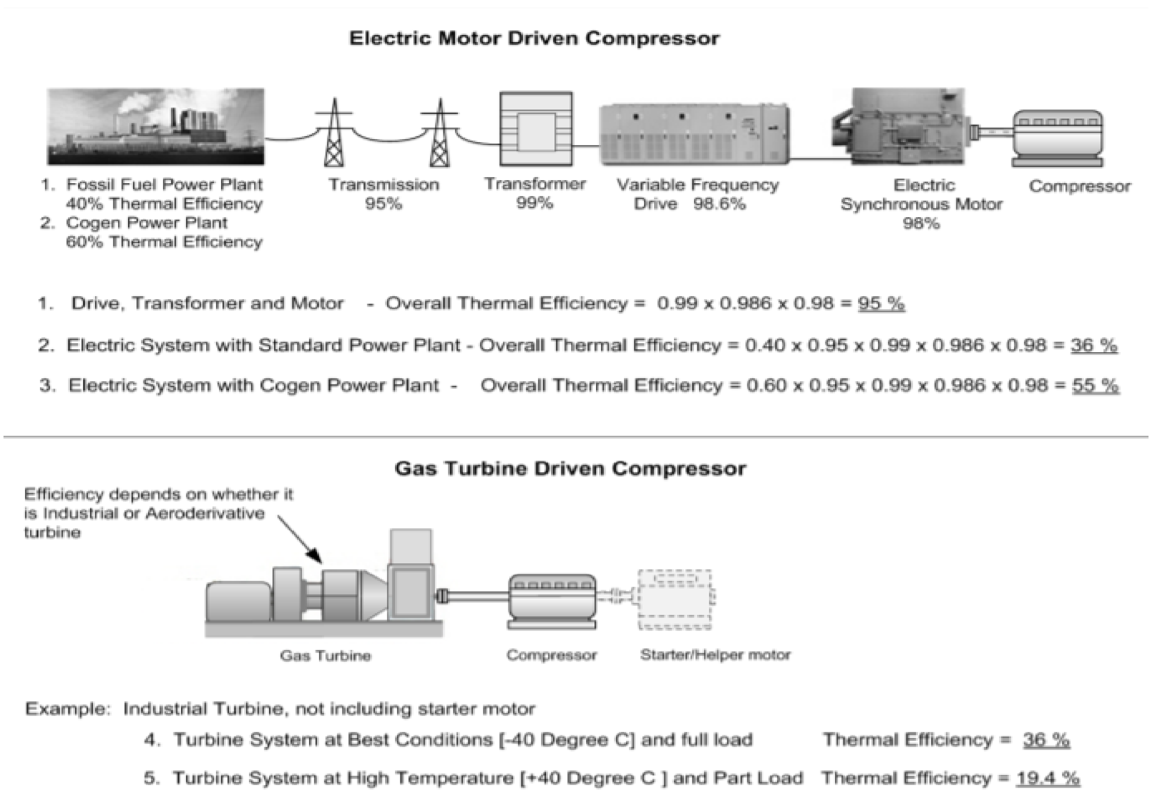
One key advantage of installing the gas-driven compressor is the accessibility to the energy source. Natural gas is readily available on the site for operating the gas compressor. From the operational view, natural gas is more reliable than electricity, where the concern is around the risk of losing power. Additionally, the commodity price of natural gas is relatively low under the current environment. Therefore, in the past, without considering the environmental benefits, the gas compressor is the primary choice for natural gas transmission companies.

2.10.2. EMD Compressor

Driven by clean electricity, the EMD compressor expects to generate much less GHG emissions at the compressor station. Additionally, the EMD compressor provides several advantages comparing to the conventional natural gas compressor, including higher thermal efficiency, low maintenance frequency, and fewer criteria air pollutants (Blaiklock, Verma, & Bondy, 2013). EMD compressor offers much higher energy efficiency compared to the gas compressor. Unlike the gas compressor with low thermal efficiency, EMD compressor could achieve much higher thermal efficiency, commonly around 95% (Blaiklock, Verma, & Bondy, 2013). Because electricity is a secondary energy source, and energy losses occur during power generation and transmission. TMEIC report performed a case study on the potential energy losses at two power plants with different thermal efficiency: a fossil fuel power plant with 40% thermal efficiency and a co-generation power plant with 60% thermal efficiency. The analysis suggested the overall efficiency of EMD compressor would be around 36% to 55% (Blaiklock, Verma, & Bondy, 2013).

Moreover, the thermal efficiency of the gas-driven compressor could be impacted by ambient temperatures. The case study in this capstone report utilized the compressor designed with 36% efficiency under the best condition. The TMEIC case study suggested the efficiency could drop to 19% if the ambient temperature reached 40 °C. The system would present lower thermal efficiency in the summer season as the air density decreases and less oxygen is pushed into the combustion chamber. The detailed thermal efficiency calculation by TMEIC can be found in Figure 11 below.

Figure 11. Efficiency comparison: EMD vs. Gas Compressor



Source: (Blaiklock, Verma, & Bondy, 2013)

Additionally, EMDs require less maintenance. TMEIC study suggested gas-driven compressor mean time between failures (MTBF) hours are range from 4,000 to 10,000 hours, and with repair time about from 0.5 to 3 days. On the other side, EMD compressor can reach up to 28 years on MTBF with repair time of about 0.5 hours.

Furthermore, installing the EMD compressor would significantly reduce Criteria air contaminants (CACs) emissions by removing the stationary combustion source at the compressor sites. If more stringent regulations on CACs emissions are implemented in the future, installing the EMD compressor could potentially help to meet the regulatory requirement and avoid additional penalties from the local regulatory body.

Chapter 3. RESEARCH METHODS

This chapter provides a detailed description of the research boundary, methods and assumptions are used to analyze the electrification opportunities, including:

- research boundary at Westcoast system,
- data selection criteria,
- data source and data quality,
- emission factors and sources,
- conversion factors and sources, and
- assumptions in the calculations.

3.1. Research Boundary

The research boundary included 15 Westcoast compressor stations listed under the Air Permit from BC Ministry of Environment, with 30 gas compressor units having a total rated power output of 448,419 kilowatts (kW) (B.C. Ministry of Environment, 2017). CSN2 Prophet River station and CS9 Rosedale station were not included in the research because they were decommissioned in 2019. A detailed list of stations with gas compressor size and model is provided in Appendix A: *Westcoast Gas Compressor Inventory*.

3.2. Data Selection Criteria

All GHG and energy-related data were collected through publicly available data sources. Those data met the research requirement as it follows predetermined reporting protocols and verification processes. The intention was to select the latest available data at the sources;

however, inconsistencies might have occurred on the latest data available year across various source. The primary data sources, including the type of data and date, are listed in Table 1.

Table 1. The Key Data Sources Selected for the Analysis

Data Source	**Data Type**	**Latest Data Available Year**	**Reference**
BC Air Permit	Westcoast Gas Compressor Inventory	2017	(B.C. Ministry of Environment, 2017)
Federal Greenhouse Gas Reporting Program	Westcoast GHG Emissions	2017	(Greenhouse Gas Reporting Program, 2020)
BC Provincial Greenhouse Gas Emissions Inventory	BC GHG Emissions for Energy Sector	2017	(Government of BC, 2019)
National Inventory Report 2020, Part 3	BC Grid Emissions Intensity	2018	(Environment and Climate Change Canada, 2020c)
Westcoast Energy Website	Fuel Gas Composition & Heat Value	March 2019- March 2020	(Enbridge, 2020)

Source: Adapted from various sources as indicated inside the table

Additionally, the compressor operational parameters and cost information were determined based on a literature research or on industrial experience within Enbridge. The calculated performance numbers, including fuel consumption and GHG emissions, were crossed checked when references were available.

3.3. Westcoast GHG Emissions

Westcoast is subjected to report its GHG performance to the Federal Greenhouse Gas Reporting Program (GHGRP), which is a mandatory program for facilities that emits GHG emissions above 10,000 tCO_2e per year. According to the GHGRP, Westcoast released approximately 1.3 million tCO_2e in 2017 (including CSN2 Prophet River station and CS9 Rosedale station). The GHG emissions breakdown by type can be found in Table 2.

Table 2. 2017 Westcoast GHG Emissions Breakdown by Type

Total CO_2e (tonnes)	**CO_2 (tonnes)**	**CH_4 (tonnes)**	**CH_4 (tCO_2e)**	**N_2O (tonnes)**	**N_2O (tCO_2e)**
1,278,506	1,047,768	8,905	222,614	27	8,124

Source: (Government of Canada, 2017)

As indicated in the table, CO_2 emissions at Westcoast pipeline were about 1 million tonnes in 2017, which was mainly due to the stationary combustion at the gas compressor sites. There are other small generators on sites that would also contribute to CO_2 emissions. Those generators are small comparing to the gas compressors and only operate periodically. Therefore, the research here assumed the emissions from those small generators were negligible, and the gas compressors were the only CO_2 emissions source. Both intended and unintended venting activities are the primary methane (CH_4) emissions sources. Intended venting refers to the gas venting during regular pipeline maintenance activities or emergency events to vent the gas to the atmosphere to reduce pipeline pressure. Unintended venting typically results in equipment design or operational practices. For example, many pneumatic devices continually bleed gas through for pressure control, and the bleed gas is vented to the atmosphere, which becomes a source for CH_4 emissions. Fugitive emission is another unintended methane emissions, such as leaks at the valve or pipeline connectors. Both vented and fugitive emissions would not be significantly reduced through the replacement of EMD compressor; therefore, the research here assumed the methane emissions would remain unchanged. Nitrous oxide (N_2O) forms during the fuel combustion process and has a significant impact on global warming potential. However, the N_2O emissions reduction was not considered in the GHG reduction calculation because N_2O emissions were minor comparing to CO_2 emissions. All the emissions indicate in

Table 2 are Scope 1 emissions. Reporting Scope 2 emissions are not required under GHGRP. Westcoast consumes a small amount of electricity at the compressor station, for office lighting and powering electric instruments. Therefore, the Scope 2 emissions were not considered under current operation or baseline evaluation because it was non-material. In the electrification scenarios, Scope 2 emissions would need to be considered to reflect the incremental power usage at the EMD compressors.

3.4. Power Infrastructure Requirement

To operate the EMD compressor at the existing compressor stations along Westcoast pipeline, it would require installing a new high voltage power line and other supporting power infrastructure between the Westcoast compressor station and the nearest power substations. Many factors would impact the cost of constructing power infrastructure, and a comprehensive engineering study would need to obtain the site-specific power infrastructure cost analysis. Appendix B: *BC Utility Transmission Line Map* outlined all the high-voltage power lines (range from 69 KW to 500 KV) within the province. To support this research activity, BC Hydro provided a preliminary assessment (BC Hydro, 2020b) on the requirements of power infrastructure at the identified compressor stations. In the preliminary screen, BC Hydro mapped out the closest substations for all 15 compressor stations. Additionally, BC Hydro also provided high-level comments on potential construction challenges at each compressor station, such as river crossing requirements, right of way access inquiry, and long interconnection cost. The summary report from BC Hydro on the compressor stations with power line connection requirement can be found in Appendix C: *Power Infrastructure Analysis at Each Gas Compressor Station: Summary Table*.

The research here assumed any available high-voltage power would meet the requirement of operating the gas compressor. After integrating the findings from BC Hydro and recommendation from industrial experts within Enbridge, a set of average costs was selected for this feasibility research's economic analysis. The selected power infrastructure costs are presented here (Lindholm, 2020):

- Transmission line cost: $800,000 per km
- Engineering and construction cost $8,000,000 per station
- BC Hydro incurred cost: $5,000,000 per station

For future project development, a detailed engineering study is recommended to determine the project feasibility and the construction cost.

3.5. Compressor Operational Parameters

As mentioned in the data quality section, a set of operational parameters were selected for the analysis. The assumption was all the compressors would operate under steady-state mode and under the same operational condition. In real operation, the compressor operational parameters could fluctuate throughout the day. The dynamic operational conditions include pipeline pressure, natural gas throughput, temperature, and maintenance schedule. In this research, the analysis focused on the overall annual GHG emissions reduction potentials rather than the day-to-day emission profile at each identified compressor. Therefore, the averaged operational parameters that reflect general compressor operations should meet the research objective. Table 3 provides all the parameters and selected values.

Table 3. Identified Operational Parameters for the Research

Operational Parameter	Value	Determined by
Compressor utilization factor	50%	Calculated value using Westcoast reported GHG emissions at the GHGRP
Gas Higher Heating Value (HHV)	39.19 MJ/m^3	Annual average (March 2019 to March 2020)
Gas compressor thermal efficiency	40%	Industrial experience
EMD compressor thermal efficiency	95%	Industrial experience
Carbon content	0.56 kg/m^3	Annual fuel composition average (March 2019 to March 2020)
Venting and Fugitive Emissions	8,905 tonnes of CH_4	(Greenhouse Gas Reporting Program, 2020)

Source: Adapted from various sources as indicated inside the table

3.6. Energy Calculation and GHG Calculation Methods

Energy consumption and GHG emissions calculations are critical when performing the analysis on GHG reduction potential and economic savings. Compressor energy consumption corresponds to compressor size, total run hours, and engine efficiency. The relation is shown in *Equation 1. Compressor Total Energy Consumption Calculation*. Compressor size typically represents by rated power or called output power in kW or horsepower (hp). The utilization factor is the ratio of compressor's in-service time to the total time of year. Engine efficiency is the thermal efficiency of the system, which indicates how much energy that releases from thermal combustion will be transferred to useful work. *Equation 2. Fuel Gas Volume Calculation* using energy consumption and higher heating value, which is the energy content per unit of natural gas. CO_2 emissions through stationary combustion are mainly due to fossil fuel intrinsic properties, such as the carbon content and heating value (Environment and Climate Change Canada, 2020b). The method selected here for *Equation 3. CO_2 Emissions at Gas Compressor Calculation* aligns with GHGRP Canada GHG emission quantification requirements (Environment and Climate Change Canada, 2019). CH_4 emission is also generated through stationary combustion and primarily technology dependent. However, as mentioned in section 3.3 Westcoast GHG Emissions, most of the CH_4 released at the natural gas pipeline is vented and fugitive. The amount of CH_4 generates through stationary combustion is minor compared to other sources. Therefore, the analysis assumed 100% fuel gas combustion efficiency with no CH_4 emissions at the stationary combustion. Although N_2O has much higher GWP than CO_2 and CH_4, it was not considered in the analysis as the relative amount is small. The fuel consumption and GHG emissions are calculated at each selected gas compressor, and the calculated results are used directly in the scenarios analysis section.

Equation 1. Compressor Total Energy Consumption Calculation, kWh/year:

$$Compressor\ total\ energy\ consumption\ = \frac{Net\ work\ output}{Thermal\ Efficiency}$$

$$= \frac{Rated\ power * Total\ run\ hours}{Thermal\ Efficiency}$$

Source: Derived from thermal efficiency calculation equation 6-3 in Cengel and Michael *(2007)*

Equation 2. Fuel Gas Volume Calculation, m^3

$$Fuel\ gas\ volume = \frac{gas\ compressor\ total\ energy\ consumption * 0.0036\frac{GJ}{kWh} * 1000\frac{MJ}{GJ}}{Gas\ HHV, MJ/m3}$$

Equation 3. CO_2 Emissions at Gas Compressor Calculation, tCO_2e

$$\begin{aligned} &CO2\ emissions\ at\ gas\ compressor \\ &\qquad = 3.664 * fuel\ gas\ volume * carbon\ content\ of\ fuel\ gas * 0.001 \end{aligned}$$

Source: adapted from GHGRP Canada's Greenhouse Gas Qualification Requirements, equation 2-8 (Environment and Climate Change Canada, 2019)

Where, the carbon content calculation is attached in Appendix D: *Carbon Content Calculation for Westcoast Pipeline.*

3.7. Grid GHG Intensity Factor

The National Inventory Report (NIR) 1990–2018: Greenhouse Gas Sources and Sinks in Canada. is published annually by Environmental and Climate Change Canada (ECCC) with a two-year lag on data. The latest NIR report is published in 2020 with 2018 Canadian GHG data. The Scope 2 emissions are calculated using the electricity grid emissions intensity presented in the NIR report, which is 12 g CO_2e/kWh electricity generation (Environment and Climate Change Canada, 2020c).

Chapter 4: ELECTRIFICATION CASE STUDY

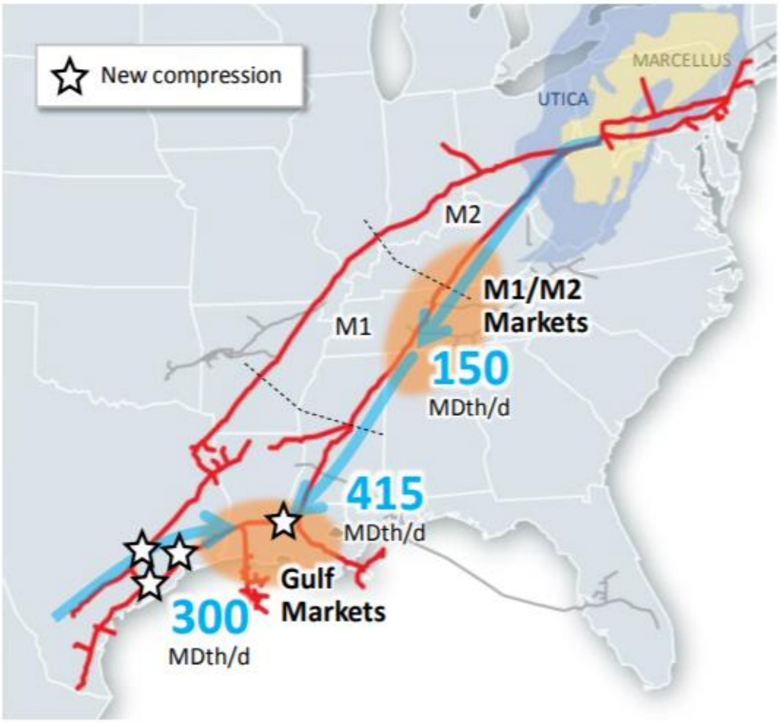
This chapter illustrates the possibility of achieving emission reduction in the natural gas sector through electrification. Two natural gas projects, one project is in operation and one is under development, claim economically viable to utilize EMD compressors to reduce operational GHG emissions. The first project is the Gulf Markets Expansion project on the Texas Eastern Transmission Pipeline, LP(TETLP), which is another of Enbridge's major natural gas transmission assets. The expansion project included installing one electric compressor at the existing gas compressor station to meet the incremental throughput on the line. The discussion is focused on analyzing the avoided CO_2 emissions and the economic benefits using EMD compressors. The other segment of this chapter discussed the BC Kitimat LNG project. The Kitimat project is still at the development phase, but it claims to be one of the world's lowest GHG intensity LNG facilities through electrification after commission. Only limited project information has made publicly available; therefore, no detailed GHG reduction and economic analysis are performed under this case.

4.1. TETLP Gulf Markets Expansion Project

TETLP is one of Enbridge's longest natural gas transmission pipelines, about 8,825 miles and across more than 10 states (Enbridge, 2019b). TETLP transfers natural gas to high demand markets in the mid-Atlantic and the Northeast for electricity generation. Meanwhile, this bi-directional pipeline also connects the natural gas supply region in the Northeast to the Gulf Coast region of Louisiana and Texas for export.

The expansion project was expected to provide an additional 650,000 dekatherms (Dth) (0.63 BCF) gas transportation capacity per day to the shippers (Spectra Energy, 2015). This expansion project was driven by the growing natural gas supply market in the northeast region, specifically, gas supply from Perryville, Barnett, Haynesville, and Fayetteville in the United States. Figure 12 below highlights the expansion project location and impacted pipeline segments. The expansion project included installing a new electric drive compressor at the existing Opelousas Compressor Station in St. Landry Parish, Louisiana, a new compressor station with gas compression at Provident City in Lavaca County, and new pipeline segments. The incremental horsepower was 17,780 hp (13,258 kW), where the electric compressor at Opelousas Compressor station has rated rate at 12,500 hp (9,321 KW), and Provident City station has gas compressors with rated rate at 5,280 hp (3,937 kW).

Figure 12. TETLP Gulf Markets Expansion Project Map



Source: (Spectra Energy, 2013)

With the cost information provided in the FERC document (Spectra Energy, 2015), economic analysis was performed to analyze the project power consumption and associated GHG reduction. According to the filed document, compression facilities have cost about USD$97 million, and pipeline facilities and meter stations facilities had an estimated cost of USD$49 million and USD$3 million, respectively. Within the USD$97 million compression facilities cost, the cost at Opelousas Compressor station was 54 million dollars, which gave approximately USD$4290/hp (USD$5793/KW), including material, engineering, and construction. The installation at Opelousas would not require additional footprint; all new installs are in the existing compressor station. However, new pipelines, tie-ins, and other supported equipment would be required to support the new electric compressor. The cost per hp was slightly higher at Provident City compressor station because the Provident City Compressor station is a new compressor station added to the TETPL system. The estimated cost per hp increased to about USD$8294/hp (USD$11611/KW), mainly resulted in increased costs on the right of way, material, and engineering.

The expansion project has projected 70% load factor and 95% thermal efficiency for the electric compressor at the Opelousas Compressor Station (Spectra Energy, 2015). With Equation 1, 2 & 3 and listed assumptions in Chapter 3, the energy consumption and GHG emissions reduction at 30% and 40% thermal efficiency using gas compressor are calculated. The results are shown below in Table 4. Calculation procedure can be found in Appendix E: *TETLP Expansion Project Energy Consumption and GHG Calculation.*

Table 4. Energy Consumption and Avoided GHG emissions at TETLP

Parameter	Value
Electric Consumption	164,835 kWh/day
Calculated Electricity Cost	USD$0.026/kWh
Natural Gas Avoided @ 30% Thermal Efficiency	47,948 m^3/day
Natural Gas Avoided @ 45% Thermal Efficiency	31,966 m^3/day
CO2 Avoided @ 30% Thermal Efficiency*	98.38 tCO_2/day
CO2 Avoided @ 40% Thermal Efficiency*	65.59 tCO_2/day

*Assumes the electricity is generated from a renewable source.

Source: Author, 2020

The estimated power cost to operate the electrical compressor at the Opelousas Compressor Station was USD$4227/day (Spectra Energy, 2015). Based on EIA, Louisiana natural gas cost for industry usage in 2015 was USD$3.33 per thousand cubic feet, or USD$0.118 per m^3 (Energy Information Administration, 2020). If the natural gas compressor was installed at the Opelousas Compressor Station, the estimated natural gas cost would be USD$3772 per day at 45% compressor thermal efficiency or USD$5658 per day at 30% thermal efficiency. Therefore, the energy cost is comparable between EMD compressor and natural gas compressor. Electricity cost will not significantly increase the energy cost at the TETLP Gulf Markets Expansion Project.

4.2. BC Kitimat LNG Project

The Kitimat LNG project is a 50-50 joint venture project between Chevron Canada Limited and Woodside Energy International Limited to develop a facility to liquefy natural gas transported from Horn River and Liard Basins area in BC (Chevron Canada, 2019). The facility is located on Bish Cove, a lease land at Haisla Nation. The initial proposal included two LNG trains, with a total processing capacity of 5 million tonnes per annum (MTPA). In 2010, the design was revised to increase the processing capacity from 5 MTPA to 10 MTPA at Kitimat facility (Kitimat LNG, 2019). Later in 2019, Kitimat further expanded its maximum proposed capacity by adding one additional processing train.

Meanwhile, the Kitimat announced the plan to electrify the facility. Comparing to the gas compressor, the EMD compressor offers more operational advantage, including higher efficiency, and compact design, with additional environmental benefit through significant GHG emissions reduction (Chevron Canada, 2019). The peak processing rate would be 18 MTPA and increase condensate production rate from 212m^3/d to 318 m^3/d (Kitimat LNG, 2019). Figure 13 shows the conceptual map of Kitimat LNG facility.

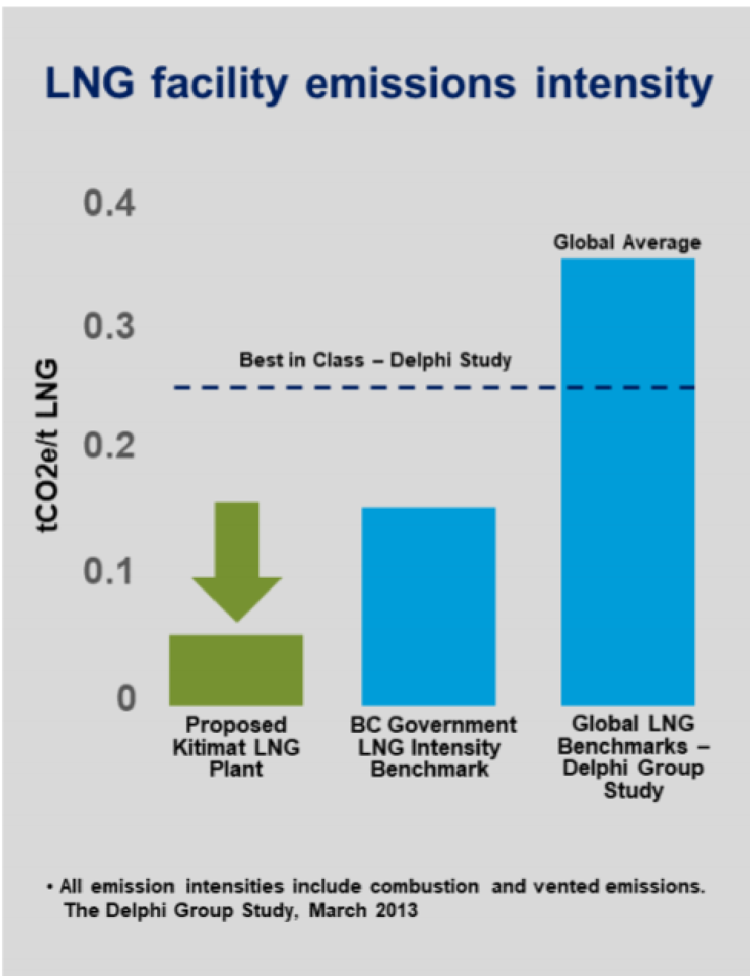
Figure 13. Conceptual map of Kitimat LNG facility

Source: *(Chevron Global, n.d.)*

Many factors could impact GHG emissions at the LNG processing facility, including the type of compressor (gas drive vs. electric drive), source of electricity (natural gas generated vs. renewable energy), age, and location of the plants. Delphi's analysis in 2018 *(Canada and the Natural Gas Economy, 2019)* evaluated 19 LNG facilities globally, and the results suggested GHG emissions intensity for a standard LNG facility ranged from approximately 0.15 to 0.44 tCO_2e /t LNG. The Kenai LNG plant was the oldest plant among the 19 LNG facilities analyzed by Delphi with emissions intensity exceed 0.44 tCO_2e /t LNG, reached 0.7 tCO_2e /t LNG. Under Clean BC

Strategy, the province aims to set the new benchmark on building the world's lowest LNG projects with GHG emissions intensity under 0.15 tCO_2e /t LNG. Kitimat claimed the Kitimat LNG facility with EMD compressors that would outperform on BC's intensity benchmark. Figure 14 compares Kitimat's GHG emissions intensity to the BC benchmark and global benchmark, where Kitimat LNG project claims to achieve GHG emission intensity around 0. 05 tCO_2e/t LNG *(Kitimat LNG, 2019)*.

Figure 14. LNG project GHG intensity comparison



Source: (Kitimat LNG, 2019)

According to Kitimat (Kitimat LNG, 2019), the plan would require building a 17 km high-voltage power transmission line from BC Hydro's Minette Substation in Kitimat to supply power to the facility. The total designed electricity capacity is 700 MW, including the process and utility compressors, pumps, and fans. In the case of the grid power outage, the plant would install 4 units of diesel generator with 10 MW capacity for critical loads. BC Hydro is conducting a Kitimat LNG Interconnection Study to identify the optimal connection plan to provide high voltage power to the LNG facility (BC Hydro, n.d.).

The project is still under development phase, the target construction time is 2022 to 2028, and the first LNG train is planned to commission in 2028/2029. No cost information is disclosed to the public. Late last year, Chevron Canada announced its plan to exit the Kitimat project by selling its 50% interest (Chevron Canada, 2019).

Chapter 5. ANALYSIS & INTERPRETATION

This chapter captures the key findings on the Westcoast pipeline electrification feasibility study. For illustrative purpose, only the calculated results for McLeod Lake compressor station is presented in this chapter. Appendix F: *Fuel Consumptions, GHG Emissions and Economic Analysis under Current Operations* include the emissions and economic analysis for the 30 gas compressors under existing gas operation condition, and Appendix G: *Electricity Consumptions. GHG Emissions and Economic Analysis after Electrification* include the analysis under the proposed electrification condition.

5.1. Capital Cost and Maintenance Cost

Led by Southwest Research Institute, the Gas Electric Partnership (GEP) Research consortium was formed in 2011. The industrial partners inside the consortium included a number of midstream companies and compressor manufacturers, such as Spectra Energy (previous Westcoast pipeline operator, acquired by Enbridge in 2017), TransCanada pipeline (now TC Energy), General Electric and Siemens (Gas Electric Partnership Research Consortium, 2012). The objective of GEP was to support the oil and gas midstream sector to better understand the viability and applicability of utilizing EMD compressors in their operations. The consortium conducted a cost comparison analysis of EMD compressor and gas compressor with the unit size range from 10 to 15 MW. This research leverages GEP's analysis and references study's capital cost and operational cost in the Westcoast calculation.

As indicated in Table 5, the capital cost between the two types of compressors is comparable. EMD compressor with variable frequency drive (VFD) is slightly more expensive than the standard gas turbine drive system, about 14% higher. However, the actual compressor's cost might be different, and many other factors could impact the compressor's cost, including compressor size, model and manufacture. Meanwhile, the operational cost of electric compressors is remarkably less than for gas-turbine compressors: $195,000 compared to $802,500 per year. The high maintenance cost of gas compressors has mainly due to the labor and annual add-on costs. Table 6 contains more information on the operational cost breakdown. Although the maintenance cost analysis performed by GEP assumed same system availability and downtime, the TMEIC case study (2013) suggests that gas compressor might require more frequent maintenance and more extended downtime in many operational cases. Therefore, higher maintenance costs and lost capacity costs might be expected for the gas compressor. Other operational costs, such as electricity costs and transmission line costs, were not included in the GEP's analysis, also play as critical consideration factors in the economic analysis. This capstone research captures those factors in the Westcoast electrification analysis and discusses how those factors impact project economic analysis.

Table 5. Capital Cost Analysis with Compressor Size of 10–15 MW

Capital Cost Items	**EMD Compressor + VFD* (thousand $)**	**Gas-turbine Drive Compressor (thousand $)**
Drive system	$6,500	$4,200
Aux Systems	$25	$55
Pumps and Coolers	$200	$80
Substation	$1,750	
Starting Equipment		$150
Construction + other equipment, etc.	$20,000	$20,000
Total Capital Cost	**$28,475**	**$24,485**

*EMD Compressor +VFD: electric-motor-driven compressor plus variable frequency drive

Source: (Gas Electric Partnership Research Consortium, 2012)

Table 6. Maintenance Cost Analysis with Compressor Size of 10–15 MW

Annual Maintenance Cost	**EMD + VFD* ($)**	**GT Drive System ($)**
Spare Parts + Labor	$30,000	$45,000
Station Operating Labor	$150,000	$675,000
Annual Add on costs (downtime project management, contractors)	$15,000	$67,500
Emissions Cost + Labor		$15,000
Availability (%)	95	95
Lost Capacity	$625,000	$625,000
Maintenance Costs	**$195,000**	**$802,500**
Gas Prices ($/MMBtu)	$4	$4

*EMD Compressor +VFD: electric-motor-driven compressor plus variable frequency drive

Source: *(Gas Electric Partnership Research Consortium, 2012)*

5.2. Natural Gas Cost

5.2.1. Westcoast Toll Settlement Agreement

Depends on the transmission toll settlement contract, many costs incurred during pipeline operation are either shared between pipeline operators and shippers or flow through to the shippers. Based on Westcoast 2018 and 2019 Transmission Toll Settlement Agreement (Enbridge, 2018), (O & M) cost, excluding pipeline integrity O & M expense, are shared 50% to the account of Westcoast and 50% to the shippers. On the other hand, gas management costs, carbon tax, and approved expansion projects are 100% flow-through costs to the shippers. In the event federal or provincial governments imposes any emission reduction requirement, Westcoast would provide a detailed emissions mitigation plan for stakeholders' approval. Although this cost-share structure allows operators to lower their operational expenses, it creates complexity for pipeline operators to initiate new projects as many projects might need shippers' consent.

Additionally, based on the toll settlement arrangement at Westcoast, Enbridge does not pay the natural gas usage at gas compressors (Enbridge, 2018). The natural gas that consumes at the gas compressors is treated as part of the system loss or “shrinkage” to the shippers.

5.2.2. Indirect Natural Gas Cost

Although there is no direct charge on the use of natural gas from an accounting perspective, the cost of natural gas should be consider as an indirect cost to shippers because they need to transport an extra volume of natural gas to make up the “shrinkage”; those volumes are not contributing to the gas selling revenue. As of January 2020, the natural gas retail rate in BC ranged from \$1.55/GJ to \$ 6.76/GJ, depending on the location, gas provider, and contracts (The Cheapest Natural Gas Rates in BC in 2020, 2020). The research here assumed the commodity-related charge of natural gas is \$2.22/GJ, which was based on Fortis BC's Rate 5 tariff for large customers with over 5,000 GJ/year natural gas usage for Mainland and Vancouver Island area (Fortis BC, 2018). The Indirect natural gas cost at McLeod Lake station is shown in Table 7.

Table 7. Calculated Indirect Fuel Cost at McLeod Lake Compressor Station

Compressor Station	**Compressor Type**	**Fuel Consumption, (m^3/year)**	**Indirect Fuel Cost (million $/year)**
CS3 McLeod Lake	Compressor Unit 5 - LM2500	18,003,448	1.6
CS3 McLeod Lake	Compressor Unit 6 - LM1600	14,252,269	1.2

5.3. CO_2 Emissions at Compressor Station

CO_2 emissions at each compressor station was calculated using the equations 1 to 3 listed under chapter 3. Calculated CO_2 emissions were considered baseline emissions at the compressor site and compared with electrification scenarios identified in the research. Since the analysis assumed all the compressors were operated under the same operational conditions, the amount of CO_2 emissions at each compressor depended solely on the rated power. According to the analysis, each compressor generated Scope 1 emissions from approximately 14,000 tCO_2 per year to 46,000 tonnes tCO_2 year, which resulted in the total Scope 1 emissions of over 1 million tCO_2 per year at Westcoast pipeline. If the compressor is electrified, the Scope 1 emissions from stationary combustion will be eliminated. Scope 2 emissions are expected to increase due to additional electricity consumption. Table 8 below illustrates the GHG emissions at CS3 McLeod Lake compressor station before and after electrification, with two natural gas compressors with the rated power of 17,897 kW and 14,168 kW, respectively.

Table 8. Calculated CO_2 Emissions at McLeod Lake Compressor Station

Compressor Station	Compressor Type	Rated Power (kW)	Emissions under Current Operation - Scope 1 (tCO_2/year)	Emissions under Electrification - Scope 2 (tCO_2/year)
CS3 McLeod Lake	Compressor Unit 5 - LM2500	17,897	37,130	990
CS3 McLeod Lake	Compressor Unit 6 - LM1600	14,168	29,394	784

5.4. Carbon Tax

As mentioned in Chapter 3, BC was the first provincial jurisdiction in Canada to introduce the carbon tax. In April 2020, BC's carbon tax increased from $35 to $40 per tCO_2e, anticipated to reach $50 per tCO_2e in 2021. The carbon tax was calculated based on fuel type and fuel volume that being consumed. At $40 per tonne, carbon tax for natural gas combustion is 7.6¢/m^3 (Government of BC, 2020a). Although Westcoast would not need to pay the gas consumed at the gas compressors, it must pay the carbon tax to the BC government for the natural gas consumed during operation. As mentioned in section 5.2.1., the carbon tax cost is a 100% flow-through cost, and shippers are responsible for reimbursing Enbridge. Table 9 below presents the carbon tax cost for McLeod Lake at the cost of $40 per tCO_2e.

Table 9. Calculated Carbon Tax at McLeod Lake Compressor Station

Compressor Station	**Compressor Type**	**Fuel Consumption (m^3/year)**	**Carbon Tax (million $/year)**
CS3 McLeod Lake	Compressor Unit 5 - LM2500	18,003,448	1,4
CS3 McLeod Lake	Compressor Unit 6 - LM1600	14,252,269	1,1

5.5. Incremental Electricity Cost

According to BC Hydro, the power requirement characteristic for the Westcoast electrification project satisfies the BC Hydro's electricity Rate Schedule 1823 (BC Hydro, 2017). Under this rate schedule, electricity price was determined under the Tier Rate with predetermined customer baseline load (CBL). For electricity charges, a lower Tier 1 electricity rate would apply to the electricity consumption below 90% of CBL. A much higher Tier 2 rate would be applied for the electricity usage exceeding 90% of CBL. Using the rate calculator (BC Hydro, 2019c) provided by BC Hydro, Tier 1 rate (below 90% CBL) and Tier 2 rate (above 90% CBL) under BC Hydro's 2021 fiscal year are $44.90/megawatt hour (MWh) and $100.60/MWh, respectively. The CBL is initially determined by BC Hydro and could be modified annually (BC Hydro, 2019b). If the power usage in the previous year fell between 90% to 110% of its CBL, the baseline will not be updated. However, if the usage falls below 90% or above 110% of its CBL, the baseline will subject to update using historical power consumption data. When calculating the power consumption after replacing with EMD, it assumed the compressor utilization factor was 50% (same as the gas compressors) with 95% thermal efficiency. Using the electricity rate calculator provided by BC Hydro, the average electricity costs were calculated under 90%, 95% and 98% of CBL, see Table 10. More information on cost breakdown at different CBL percentages can be found in Appendix H: *Electricity Unit Cost under Different CBL Usage Percentage*.

Table 10. Rate Schedule 1823 and Average Unit Electricity Cost at Different CBL Usage Percentage

F2021 - Rate Schedule 1823 Energy Charge**	**Price ($)**
RS 1823 Tier 1 Rate ($/MWh)	44.90
RS 1823 Tier 2 Rate ($/MWh)	100.60
RS 1823 Demand Charge ($/kVA)	8.609
Average Electricity Cost at 90% CBL ($/MWh)	**71.91**
Average Electricity Cost at 95% CBL ($/MWh)	**74.83**
Average Electricity Cost at 98% CBL ($/MWh)	**76.59**

** F2021 represents BC Hydro's 2021 fiscal year, where is from April 2020 to March 2021.

Source for rate schedule 1823 Energy Charge: (BC Hydro, 2017)

The research assumed 95% CBL after electrification, which should provide a reasonable basis for incremental electricity consumption. Sensitivity analysis of the impact of electricity price on the project's O & M cost was included in the sensitivity analysis section. The calculated power cost for McLeod Lake station is outlined below in Table 11.

Table 11. Calculated Electricity Cost at McLeod Lake Compressor Station

Compressor Station	**Compressor Type**	**Electricity Usage (MWh)**	**Electricity Cost (million $)**
CS3 McLeod Lake	Compressor Unit 5 - LM2500	82,515	6.2
CS3 McLeod Lake	Compressor Unit 6 - LM1600	65,322	4.9

5.6. Power Infrastructure Cost

As mentioned in Chapter 3, the research here assumed that any available high voltage line near the compressor station would meet the tie-in requirement. There were three cost elements consider in the analysis: transmission line cost, Enbridge engineering and construction cost, and cost paid to BC Hydro for system upgrade. The transmission cost was calculated by the distance of the transmission power line. The other two costs were applied at the compressor station level. Table 12 shows the calculated power infrastructure cost at McLeod Lake Compressor Station.

Table 12. Calculated Power Infrastructure Cost at McLeod Lake Compressor Station

Compressor Station	**Compressor Type**	**Transmission Line Cost (million $)**	**Engineering, Construction, and Cost to BC Hydro (million $)**
CS3 McLeod Lake	Compressor Unit 5 - LM2500	12	12
CS3 McLeod Lake	Compressor Unit 6 - LM1600	12	

Chapter 6. DISCUSSIONS

The first segment of the section discusses the various electrification approaches for the Westcoast pipeline. Three electrification scenarios were selected for detailed cost-benefit analysis. The electrification scenarios include S1) rapid approach scenario; S2) steady approach scenario; S3) practical approach scenario. The scenario analysis focused on evaluating the aggregated impact on the pipeline system, rather than individual compressor station. The cost-benefit analysis included quantitative GHG emissions analysis and economic impact at the Westcoast pipeline compared to the baseline scenario. The baseline scenario assessed the GHG emissions and O & M cost under existing Westcoast operational philosophy. Appendix I: *Westcoast Electrification Scenario Analysis* contains a summary of the scenario analysis.

As indicated in Chapter 3, a set of predetermined cost parameters were selected during the research; however, the cost parameters were dynamic numbers and could change in the future. To understand the impact of using firmed cost parameters, the second segment of this chapter includes the sensitivity analysis for baseline and S3 scenario. The sensitive analysis calculated the O & M cost using a lower limit and an upper limit of the cost parameter. The parameters that might potentially impact the O & M cost include gas compressor maintenance cost, natural gas market price, carbon tax, and electricity cost.

The incremental electricity consumption during electrification would have a critical impact on Westcoast O & M cost. Therefore, this chapter also provides a qualitative discussion on the opportunity of partially offset the electricity bill by implementing onsite renewable generation. Although the opportunities exist with self-power, many factors could drive the decision-making process. The factors that need to be considered would include power demand, site availability, site location. The research here focuses on discussing the conceptual idea of developing onsite solar power generation to offset part of the electricity demand of selected 12 aged gas compressors. A site-specific engineering study is recommended if Westcoast is interested in testing the self-power concept.

6.1. Scenario Analysis

S1 - Rapid approach Scenario: this scenario evaluates the impact on fully electrifying the 30 gas compressors on the Westcoast pipeline. This scenario achieves the optimum GHG emissions reduction; meanwhile, it has the highest incremental cost because of the size of the replacement scope. Additionally, the electricity consumption at all 30 compressors would drive up the operational cost comparing to baseline operation. This approach is not recommended unless more stringent environmental regulations put in place or Enbridge commits to ambitious GHG emissions reduction targets.

S2 – Steady approach scenario: this scenario considers the lifespan of the compressor and its replacement schedule. After examining Westcoast gas compressors' installation years and utilization factors, 17 out of 30 gas compressors on the Westcoast system were selected for high priority for replacement. The scenario includes cost-benefit analysis of electrifying the 17 gas compressors during the equipment replacement. This approach could significantly reduce the incremental capital expenditure at the Westcoast pipeline system. The replacement plan should already be captured in the asset planning process, and capital cost is allocated for the replacement work. The replacement here is driven by pipeline reliability concerns; therefore, the cost could be potentially recoverable from shipper under the existing toll settlement agreement. The operational cost would be lower than S1 as only 17 aged compressors are powered with clean electricity. However, this scenario's equipment maintenance cost is higher than S1 due to the remaining gas compressors. The expected total O & M cost would be lower than S1, but it is still not comparable with the baseline case.

S3 – Practical approach scenario: this scenario factors the financial feasibility of constructing power infrastructure to support the electrification project. In addition to the engineering and construction cost and the system upgrade cost to BC Hydro, the average cost to run the power line between the compressor station and the substation is $800,000 per km. In this scenario, it assumed any power line connections cost exceed $20 millions (or over 25 km connection distance) would be too expensive and deemed economically unpractical. Only 12 out of 17 compressors meet the threshold and are included in the scenario. The result indicated the project O & M cost is the lowest among all three scenarios but still higher than the base case.

A summary of the key findings presents in Table 13 below. The *S1 Rapid Approach* would provide the highest GHG emissions reduction opportunity because all the compressor stations will run under clean electricity. However, this scenario also has the highest cost, including capital expenditure and O & M expenditure. The *S2 Steady Approach* will eliminate the incremental capital expenditure on compressors replacement. However, the required investment on power infrastructure is still significant because of the physical challenge on accessing some BC Hydro's power substations for high voltage power supply. Although the *S3 practical approach* has the lowest expected capital expenditure and O & M cost, the O & M cost is still slightly higher than the baseline case. Among all three scenarios, if Westcoast would proceed with electrification, the S3 practical approach is recommended because it could achieve substantial GHG emissions reduction while maintaining economic viability.

Table 13. Summary of Westcoast Electrification Scenario Analysis

Scenario	Baseline	S1 Rapid Approach	S2 Steady Approach	S3 Practical Approach
Compressor Count	30	30	17	12
Compressor Station Count	15	15	11	9
GHG Emissions				
Scope 1 Emissions – Combustion, tCO2e	1,009,000	0	519,000	378,000
Scope 1 Emissions – Venting/Fugitive, tCO2e	223,000	223,000	223,000	223,000
Scope 2 emissions, tCO2e	0	28,000	13,000	10,000
Total Scope 1 & 2 Emissions, tCO2e	1,232,000	250,000	755,000	611,000
Energy Consumptions				
Fuel Gas Consumption (millions m^3)	489	-	252	306
Incremental Electricity (GWh)	0	2,243	1,090	840
Economic Analysis				
Incremental Capital, million $		$854	$0	$0
O & M (including Indirect Fuel Gas Saving), million $/year	$61	$94	$92	$78
Power Infrastructure Cost, million $		$751	$545	$175

6.2. Sensitivity Analysis

Many uncertainties exist with the predetermined cost parameters, which could potentially evolve in the future. Hence, the sensitivity analysis is necessary to discuss the uncertainties and how the uncertainties might impact the financial analysis on the Westcoast electrification. As indicated in the scenario analysis section, *S3 Practical Approach* is recommended for Westcoast to lower its emissions through electrification. However, the O & M cost for S3 is still slightly higher than the baseline case due to the incremental electricity cost. Therefore, the sensitivity analysis focused on comparing the impact on project O & M cost for S3 and baseline with changing cost variables. The cost parameters that included in the analysis are gas compressor maintenance cost per unit, natural gas cost, carbon tax cost, and power cost. The tornado diagrams, Figure 15, 16 & 17, represent the variables and calculated O & M cost for S3 and baseline scenarios.

The sensitive analysis for the baseline scenario is shown below in Figure 15. As mentioned in section 5.2, Westcoast is not charged for the natural gas usage; therefore, fluctuations in the natural gas price would not impact the baseline O & M cost. Also, the variation in electricity cost would not shift the O & M cost as all compressors are operating under the natural gas environment. The gas compressor maintenance cost would have a significant effect on the baseline. Maintenance cost might be various depending on compressor's conditions, as the cost is correlated with the compressor's condition. The carbon tax is another factor that might lead to higher O & M cost. Although natural gas is free to Westcoast, it would still penalize through carbon tax for the gas consumed onsite. With the expectation that the carbon tax will reach $50 by 2022 and possibly higher after, the O & M cost would increase with a higher carbon tax.

Figure 15. Tornado Diagram - Baseline Scenario O & M Cost Sensitivity Analysis

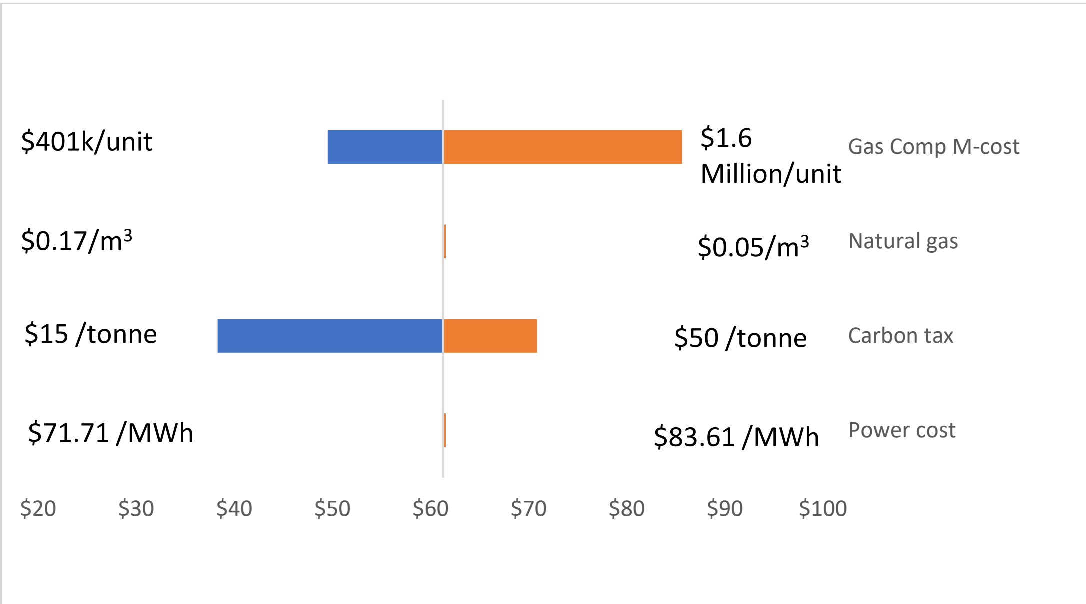


Figure 16 is the sensitive analysis result for the *S3 practical approach* O & M cost. Since S3 operates both EMD compressors and gas compressors, higher gas compressor maintenance cost would drive up the overall compressor maintenance cost. Meanwhile, increasing carbon tax would result in negative impact on the O & M cost under this scenario. Additionally, the natural gas cost will significantly drive the O & M cost in this case. Since the natural gas cost is at a lower value and expected to bounce back in the long run, the O & M cost could be lower if the natural gas price escalates.

Figure 16. Tornado Diagram - S3 Practical Approach O & M Cost Sensitivity Analysis

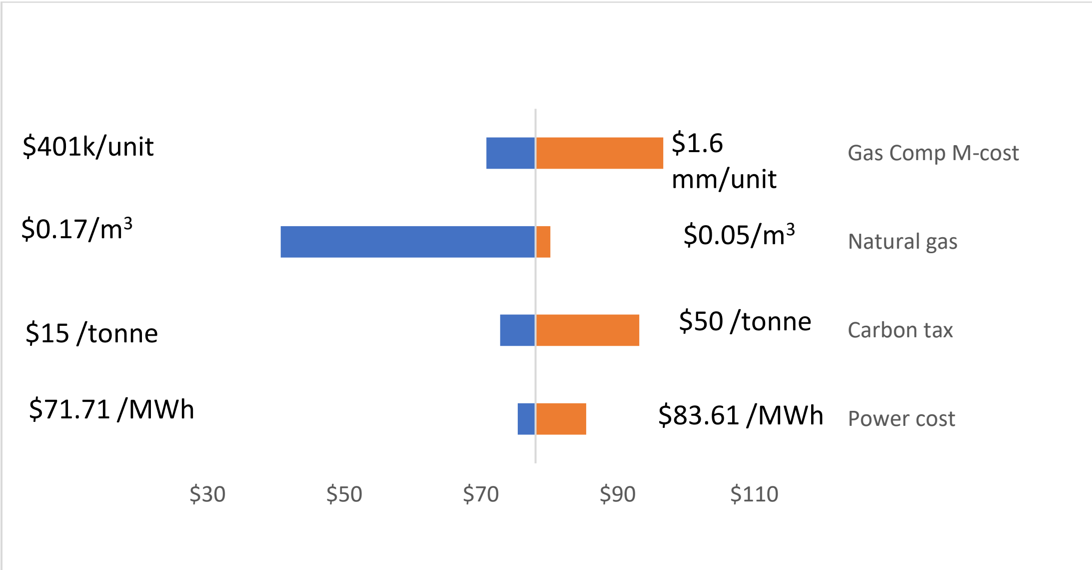
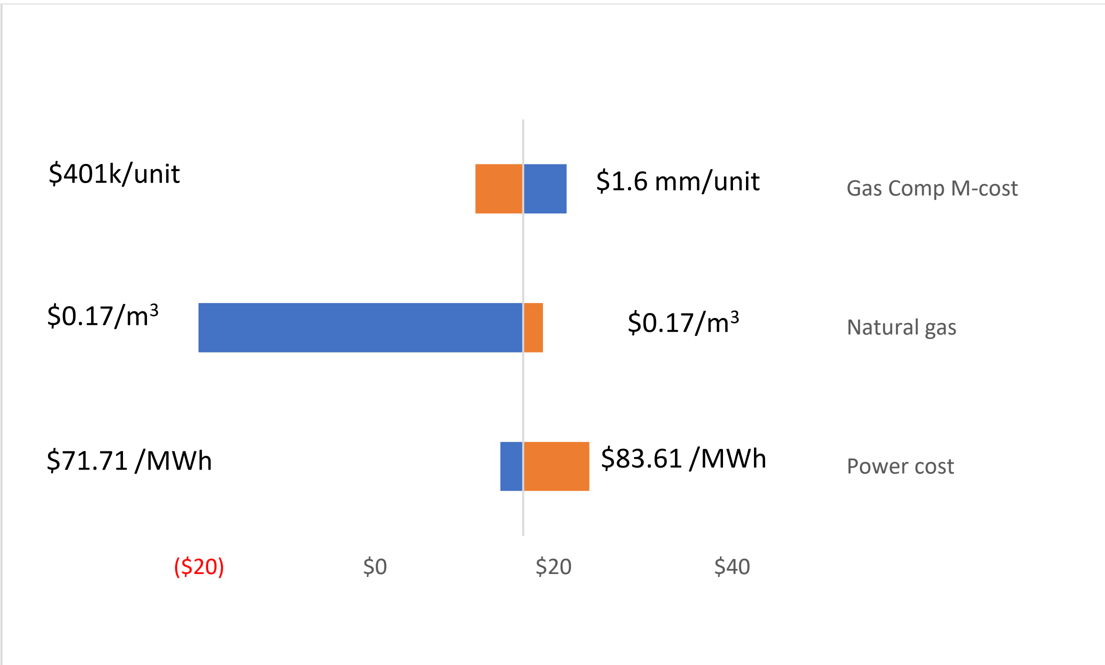


Figure 17 illustrates the cost differences between S3 and baseline and presents under what condition the S3 will have lower O & M cost than baseline. It appears if the natural gas cost increases significantly, the S3 would have a competitive O & M cost to the baseline.

Figure 17. Tornado Diagram – S3 Practical Approach Incremental O & M Cost comparing to Baseline Scenario



6.3. Self-Power Opportunity

To address the incremental electricity cost, one solution is to negotiate with BC Hydro for a lower power rate, possibly through a long-term power purchase agreement. Alternatively, generating renewable electricity at the compressor station could be another solution. The concept is to construct a solar farm beside the compressor station to substitute site power requirements. Although this approach would require additional capital investment on the renewable power plant, for the facility with anticipated long service life, the cost on the solar plant might be recoverable through the power cost saving. Many factors would drive the cost for self-power, and it would have to be evaluated case by case with detailed engineering and environmental study. In Canada, the average installation cost for the solar power plant is about

$1.5/W with the expectation to drop to $0.8/W in the future (Canada Energy Regulator, 2020c). Declining installation cost would potentially advance the economic benefits of the self-power approach. However, the self-power approach might not eliminate the requirement to connect to a high voltage power line to ensure the supply of reliable and consistent power throughout the year.

Chapter 7. CONCLUSIONS and RECOMMENDATIONS

This chapter concludes the feasibility study for Westcoast electrification. Research limitations and future recommendations are also discussed here.

7.1. Conclusion

Because of the complexity of the pipeline operations and the extensive geographic coverage of the pipeline network, natural gas midstream operators need to explore different opportunities to achieve substantial GHG emissions reduction. Electrification could be one of the pathways to support the GHG emissions reduction goal for natural gas midstream companies, including Enbridge. This research study could act as the preliminary analysis for Enbridge to examine the electrification feasibility at Westcoast pipeline. The study indicates there is a great potential to reduce operational-related GHG emissions by electrifying gas compressors. The *S1 rapid transition* scenario indicates electrifying all gas compressors would reduce total GHG emissions from 1.2 million tCO2e per year to less than 300 thousand tCO2e per year. In the *S2 Steady Approach* and *S3 Rapid Approach* scenarios, both cases GHG emissions are less than 700 thousand tCO2e per year, which is an over 40% reduction from the baseline scenario. Although S1 could achieve the optimum GHG reduction, it is determined to be unpractical due to the economic constraints. It is recommended to partner the electrification with the compressor future replacement schedule and slowly convert the gas compressors to EMD compressors.

Another key factor to consider is the power infrastructure cost, which is sensitive to the physical distance to BC Hydro's power substations. Therefore, the compressor stations with long distances to the substations are not recommended to operate with EMD compressors with power supplied by BC Hydro. Since electrifying natural gas operation aligns with BC's emissions reduction strategy, the project might be eligible for government subsidies, which can potentially offset part of the project cost, including power infrastructure cost.

One major challenge to impose pipeline electrification is the incremental electricity cost and its impact on annual O & M cost. The TETLP expansion project is one example that low electricity cost would support the movement of pipeline electrification. However, under current BC Hydro's power rate structure, the O & M cost after electrification is much higher than the baseline case. Before committing to installing EMD compressors, this incremental electricity cost needs to justify to the shippers, which creates uncertainties on how shippers would react to the proposed change, especially under the current low commodity price environment.

7.2. Research Limitations

The limitations of this research are primary around the data collection and the assumptions that were selected during the analysis. Because it is a public-facing research project, all data were gathered through publicly available data sources and used the industrial average operational parameters to avoid disclosing any sensitive operational information. Data availability limits the ability to gather the most current data on the pipeline. Therefore, some information might be outdated and not reflect the real operational conditions. The industrial averaged parameters might lead to overestimated or underestimated fuel consumption value and GHG emissions value at the compressor.

7.3. Future Research

To gain a better understanding of the engineering requirement at Westcoast, a more comprehensive engineering study is recommended for the *S3 Practical Approach* Scenario. The detailed engineering study should engage with the key stakeholders, including Enbridge Westcoast operations, BC Hydro, and local communities. The detailed engineering study would further refine the analysis using Westcoast operational data and specific site information. Further exploring the self-power concept is also recommended during the detailed engineering study. Self-power has great potential to offset the incremental power cost due to electrification and create economic opportunities to Enbridge.

It also suggests socializing the electrification concept with local shippers to gather their feedback. It is essential to have shippers accept the proposed electrification project. Starting the discussions at the early stage would allow Enbridge to acknowledge potential concerns and to develop a mitigation plan accordingly.

If Enbridge decides to electrify the Westcoast pipeline, the implication on local energy supply needs to be considered. High electricity demand is expected after bringing EMD compressors online. Backstopping the development of the BC Hydro infrastructure development would ensure EMD compressor operational reliability.

An environmental impact assessment of Westcoast pipeline electrification is another area that could be considered for future research. As indicated in BC Hydro's preliminary analysis on power infrastructure requirements, potential challenges might occur for some interconnections to substation as the construction work would require ground disturbance, including private land, parks, and communities.

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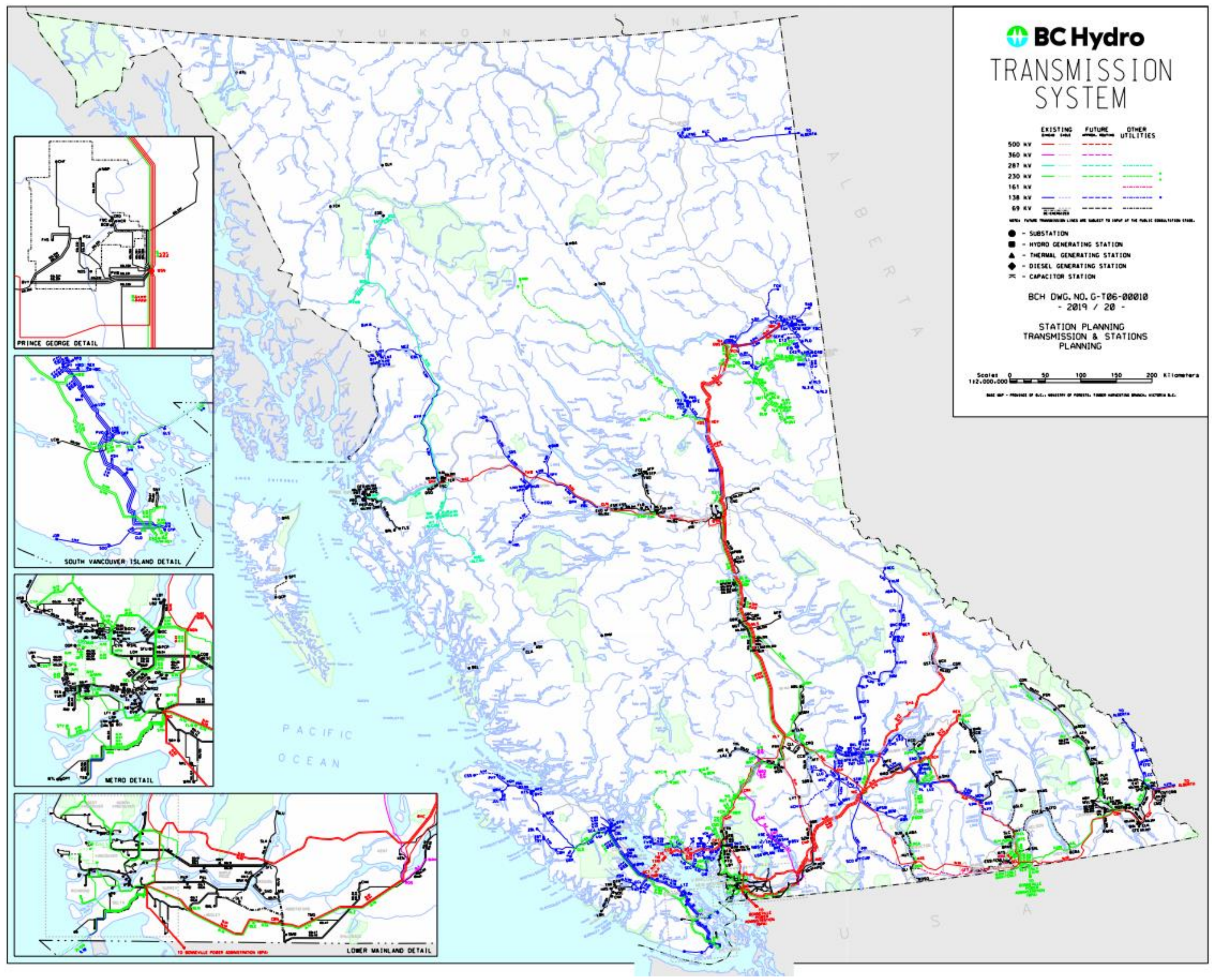
APPENDIX A: Westcoast Gas Compressor Inventory

Station	Compressor Unit	Rated Power (kW)
CSN3 Sikanni Chief	Compressor Unit 1, LM1500	10,567
	Compressor Unit 2, LM1500	10,567
CSN4 Cypress	Compressor Unit 1, LM1500	10,567
	Compressor Unit 2, LM1500	10,567
	Compressor Unit 10 - Solar Titan 250	22,371
CSN5 Mackie Creek	Compressor Unit 1, LM1500	10,567
	Compressor Unit 2, LM1500	10,567
CS2 Willow Flat	Compressor Unit 1, LM 1500	10,567
	Compressor Unit 2, LM1500	10,567
	Compressor Unit 4, LM 1600	14,168
CS2B Azouzetta Lake	Compressor Unit 1-Spey	11,931
	Compressor Unit 10 - LM2500GJ-DLE	18,493
CS3 McLeod Lake	Compressor Unit 5 - LM2500	17,897
	Compressor Unit 6 - LM1600	14,168
CS4A Summit Lake	Compressor Unit 1 - Spey	11,931
	Compressor Unit 3 - LM2500	23,266

CS4B Hixon	Compressor Unit 1 - Spey	11,931
	Compressor Unit 3 -LM2500	23,266
CS5 Australian	Compressor Unit 7 - LM2500	23,266
CS6A 150 Mile House	Compressor Unit 1 - SPEY	11,931
	Compressor Unit 10 - LM2500GJ-DLE	18,493
CS6B 93 Mile House	Compressor Unit 2 - Spey	11,931
	Unit 10 - PGT 25+	30,929
CS7 Savona	Compressor Unit 10 -LM2500GJ-DLE	18,493
	Compressor Unit 20 - LM2500GJ-DLE	18,493
CS8A Kingsvale	Compressor Unit 2 - Spey	11,931
	Unit 10 - PGT 25+	30,929
CS8B Othello	Compressor Unit 10 - LM2500GJ-DLE	18,493
CS16 Sunset Creek	Compressor Unit 1 – Solar Titan 130	15,290
	Compressor Unit 2 – Solar Titan 250	22,371
Total	**30 Units**	**448,419**

APPENDIX B: BC Utility Transmission Map



APPENDIX C: Power Infrastructure Analysis at Each Gas Compressor Station: Summary Table

BC Hydro
Power smart

Enbridge Compressor Stations – Summary Table

Name	Load (kW)	Closest BC Hydro Transmission Assets	Approximate Distance to BC Hydro Transmission Assets (km) *(straight line, unless otherwise noted)*	Notes
CS N2 (Prophet River)	13,422	None	>70	• Interconnection to BC Hydro transmission system would be prohibitively expensive due to distance.
CS N3 (Sikanni Chief)	21,134	None	>70	
CS N4 (Cypress)	43,505	None	>70	
CS N5 (Mackie Creek)	21,134	Portage Pass Substation (PPS)	>20	•
		1L364, 1L360	20	•
CS 1 (McMahon Compressor at Taylor)		1L375	<1	•
		1L377, 1L375FBC	<1	•
CS 16 (Sunset Creek)	37,661	1L358	20 *south to 208 Road then east, to terminus of 1L358*	• Capacity constraints exist on 1L358
		2L333, Shell Groundbirch Substation (SGB)	25 *south to 208 Road then west, to SGB*	• Not considered due to high cost of interconnecting to 230 kV system
CS A1 (Gordondale)		1L377	>30	• High interconnection cost, due to distance
		Dawson Substation (DAW)	>30	• High interconnection cost, due to distance and work that would be required at DAW
CS 2 (Willow Flats)	35,302	Dokie Terminal Substation (DKT)	20	•
		Sukunka Switching Station (SNK), Chetwynd Substation (CWD)	>35	• High interconnection cost, due to distance
		2L309	20	• Not considered due to high cost of interconnecting to 230 kV system

BC Hydro
Power smart

Enbridge Compressor Stations – Summary Table

Name	Load (kW)	Closest BC Hydro Transmission Assets	Approximate Distance to BC Hydro Transmission Assets (km) *(straight line, unless otherwise noted)*	Notes
CS 2B (Azouzetta)	30,424	1L373	>45 *paralleling Hwy 97*	• High interconnection cost, due to distance
		Morphee Substation (MFE)	>30	• High interconnection cost, due to distance
		Kennedy Substation (KDS)	>40 *paralleling Hwy 97*	• High interconnection cost, due to distance
CS 3 (McLeod Lake)	32,065	1L373	*15* *paralleling Hwy 97*	•
		1L365	15	•
		Kennedy Substation (KDS)	15	• Station constraints may exists
CS 4A (Summit Lake)	35,197	1L365	<1	•
		McEwan Substation (MWN)	>15	•
		Salmon Valley Substation (SVY)	>15	•
CS 4B (Hixon)	35,197	60L339	2	• Conceptual Review would be required to determine whether 69 kV line can support the required load
		Colebank Substation (CLB)	25	• High interconnection cost, due to distance
		Williston Substation (WSN)	>35	• High interconnection cost, due to distance
CS 5 (Australian)	23,266	60L300	<2	• Conceptual Review would be required to determine whether 69 kV line can support the required load • Requires river crossing
		Marguerite Substation (MGT)	<2	• Requires river crossing

BC Hydro
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Enbridge Compressor Stations – Summary Table

Name	Load (kW)	Closest BC Hydro Transmission Assets	Approximate Distance to BC Hydro Transmission Assets (km) *(straight line, unless otherwise noted)*	Notes
CS 6A (150 Mile House)	30,424	60L308	>10	• Potential challenges acquiring right of way due to presence of highway and private property in and around community of Williams Lake
		2L352		• Not considered due to high cost of interconnecting to 230 kV system
		Williams Lake Substation (WLM)	>10	•
		Soda Creek Substation (SCK)	>25	•
CS 6B (93 Mile House)	42,860	60L301	>5	• Conceptual Review would be required to determine whether 69 kV line can support the required load
		100 Mile Substation (HMH)	>10	•
		2L086	10	• Not considered due to high cost of interconnecting to 230 kV system
CS 7 (Savona)	36,986	1L203	<1	•
		Savona Substation (SVA), Highland Substation (HLD)	>20	• High interconnection cost, due to distance
CS 8A (Kingsvale)	42,860	1L251	25	• High interconnection cost, due to distance • Technical challenges due to required crossing of three 500 kV circuits (5L083, 5L082, 5L081)
		Merritt 2 Substation (MR2)	>25 *paralleling Hwy 5*	• High interconnection cost, due to distance • Potential challenges acquiring right of way due to presence private property in and around community of Merritt

BC Hydro
Power smart

Enbridge Compressor Stations – Summary Table

Name	Load (kW)	Closest BC Hydro Transmission Assets	Approximate Distance to BC Hydro Transmission Assets (km) *(straight line, unless otherwise noted)*	Notes
CS 8B (Othello)	18,493	60L095 60L010HOP Hope Substation (HOP)	<5 <5 <5	• Potential challenges acquiring right of way due to presence of highway, parks, and private property in and around community of Hope
CS 9 (Rosedale)	13,720	60L093KEN	1	• Conceptual Review would be required to determine whether 69 kV line can support the required load

APPENDIX D: Carbon Content Calculation for Westcoast Pipeline

Date	HHV (MJ/m^3)	Spec Gravity	CO_2 (mol%)	N_2 (mol%)	CH_4 (mol%)	C_2H_6 (mol%)	C_3H_8 (mol%)	C_4H_{10} (mol%)	I-C_5H_{12} (mol%)	N-C_5H_{12} (mol%)	C_6H_{14} (mol%)	Density (kg/m^3)
Mar-19	38.9	0.59	0.88	0.45	93.39	4.97	0.24	0.02	0	0	0.01	590
Apr-19	39.68	0.6	0.65	0.39	92.31	5.57	0.82	0.1	0.02	0.01	0.01	600
May-19	38.9	0.59	0.87	0.46	93.47	4.81	0.31	0.03	0.01	0	0.01	590
Jun-19	40.77	0.61	0.29	0.24	90.8	6.76	1.37	0.22	0.03	0.02	0.02	610
Jul-19	39.44	0.6	0.7	0.42	92.52	5.62	0.56	0.07	0.01	0.01	0.01	600
Aug-19	38.9	0.59	0.82	0.44	93.48	5.02	0.19	0.02	0	0	0.01	590
Sep-19	38.79	0.59	0.81	0.42	93.85	4.76	0.13	0.01	0	0	0.01	590
Oct-19	39.62	0.6	0.86	0.46	91.71	6.03	0.73	0.07	0.02	0.01	0.02	600
Nov-19	38.86	0.59	0.77	0.49	93.7	4.69	0.26	0.03	0.01	0	0.01	590
Dec-19	38.93	0.59	0.81	0.42	93.65	4.69	0.33	0.04	0.01	0	0.01	590
Jan-20	38.89	0.59	0.81	0.41	93.77	4.62	0.3	0.03	0.01	0	0.01	590
Feb-20	38.84	0.59	0.8	0.43	93.88	4.55	0.27	0.03	0.01	0	0.01	590
Mar-20	38.91	0.59	0.81	0.43	93.66	4.73	0.3	0.03	0.01	0	0.01	590
Average	**39.19**	**0.59**	**0.76%**	**0.42%**	**93.09%**	**5.14%**	**0.45%**	**0.05%**	**0.01%**	**0.00%**	**0.01%**	594
Mass %			2%	1%	85%	10%	1%	0%	0%	0%	0%	
Total Carbon Content, %		83%										
Total Carbon Content, kg/m3		0.56										

APPENDIX E: TETLP Expansion Project Energy Consumption and GHG Calculation

Daily energy consumption, kWh/day:

$$\frac{9321 \text{ KW} * 24 \text{ hr} * 70\%}{95\%} = \ 164{,}835 \frac{\text{kWh}}{\text{day}}$$

Electricity Cost, \$/kWh:

$$\frac{\$4227/day}{164{,}835\ kWh/day} = \frac{\$0.026}{kWh}$$

Where,

assumed the electric compressor has utilization factor of 70% and thermal efficiency is 95%.

Theoretically, gas compressor efficiency can range from 30%-45%, depending on the type of the compressor. Natural gas avoided by operating electricity compressor can be calculated:

Natural Gas Avoided @30% efficiency, m^3/day:

$$9{,}321 * 24 * 70\% \ \frac{kWh}{day} * \frac{1}{30\%} * \frac{0.0036\ GJ}{1\ kWh} * \frac{1\ m3}{0.03919\ GJ} = 47{,}948 \frac{m3}{day}$$

Natural Gas Avoided @ 45% efficiency, m^3/day:

$$9{,}321 * 24 * 70\% \ \frac{kWh}{day} * \frac{1}{45\%} * \frac{0.0036\ GJ}{1\ kWh} * \frac{1\ m3}{0.03919\ GJ} = 31{,}966 \frac{m3}{day}$$

Where,

assumed natural gas HHV is 0.03919 GJ/m^3.

Additionally, CO_2 avoided through natural gas combustion can also be estimated here:

CO_2 Avoided @ 30% efficiency, tCO_2/day:

$$3.664 * 47{,}948 \frac{m3}{day} * 0.56 \frac{kg}{m3} * 0.001 = 98.38 \text{ tCO}_2\text{/day}$$

CO_2 Avoided @ 45% efficiency, tCO_2/day:

$$3.664 * 31{,}966 \frac{m3}{day} * 0.56 \frac{kg}{m3} * 0.001 = 65.59 \text{ tCO}_2\text{/day}$$

Where,

emission was calculated based on Equation 3. CO_2 Emissions at Gas Compressor Calculation, tCO_2e;

assumed carbon content CC_i is 0.56 kg/m3 in the natural gas (Westcoast pipeline 2019 carbon content value, Appendix 4).

Based on EIA, Louisiana natural gas cost for industry usage in 2015 was \$3.33 per thousand cubic feet, or \$0.118 per m3 (Energy Information Administration, 2020).

Natural gas for operating gas compressor @30% efficiency, \$/day:

$$\frac{47{,}948m3}{day} * \frac{\$0.118}{m3} = \frac{\$5{,}658}{day}$$

Natural gas cost for operating gas compressor @45% efficiency, \$/day:

$$\frac{31{,}966m3}{day} * \frac{\$0.118}{m3} = \frac{\$3{,}772}{day}$$

APPENDIX F: Fuel Consumption, GHG Emissions and Economic Analysis under Current Operation

Station	Compressor Unit	Rated Power (kW)	Gas Compressor Energy Consumption (kWh)	Energy Consumption (GJ/year)	Fuel Volume (m^3)	Scope 1 Emissions (tCO2e/year)	Potential Natural Gas Cost ($)	Carbon Tax Cost ($)
CSN3 Sikanni Chief	Compressor Unit 1, LM1500	10,567	115,708,650	416,551	10,629,851	21,923	924,744	807,869
CSN3 Sikanni Chief	Compressor Unit 2, LM1500	10,567	115,708,650	416,551	10,629,851	21,923	924,744	807,869
CSN4 Cypress	Compressor Unit 1 & 2, LM1500	10,567	115,708,650	416,551	10,629,851	21,923	924,744	807,869
CSN4 Cypress	Compressor Unit 1, LM1500	10,567	115,708,650	416,551	10,629,851	21,923	924,744	807,869
CSN4 Cypress	Compressor Unit 10 - Solar Titan 250	22,371	244,962,450	881,865	22,504,059	46,412	1,957,740	1,710,308
CSN5 Mackie Creek	Compressor Unit 1, LM1500	10,567	115,708,650	416,551	10,629,851	21,923	924,744	807,869
CSN5 Mackie Creek	Compressor Unit 2, LM1500	10,567	115,708,650	416,551	10,629,851	21,923	924,744	807,869
CS2 Willow Flat	Compressor Unit 1, LM 1500	10,567	115,708,650	416,551	10,629,851	21,923	924,744	807,869
CS2 Willow Flat	Compressor Unit 2, LM1500	10,567	115,708,650	416,551	10,629,851	21,923	924,744	807,869
CS2 Willow Flat	Compressor Unit 4, LM 1600	14,168	155,139,600	558,503	14,252,269	29,394	1,239,876	1,083,172

Station	Compressor Unit	Rated Power (kW)	Gas Compressor Energy Consumption (kWh)	Energy Consumption (GJ/year)	Fuel Volume (m^3)	Scope 1 Emissions (tCO2e/year)	Potential Natural Gas Cost ($)	Carbon Tax Cost ($)
CS2B Azouzetta Lake	Compressor Unit 1-Spey	11,931	130,644,450	470,320	12,001,963	24,753	1,044,110	912,149
CS2B Azouzetta Lake	Compressor Unit 10 - LM2500GJ-DLE	18,493	202,498,350	728,994	18,602,993	38,366	1,618,367	1,413,827
CS3 McLeod Lake	Compressor Unit 5 - LM2500	17,897	195,972,150	705,500	18,003,448	37,130	1,566,209	1,368,262
CS3 McLeod Lake	Compressor Unit 6 - LM1600	14,168	155,139,600	558,503	14,252,269	29,394	1,239,876	1,083,172
CS4A Summit Lake	Compressor Unit 1 - Spey	11,931	130,644,450	470,320	12,001,963	24,753	1,044,110	912,149
CS4A Summit Lake	Compressor Unit 3 - LM2500	23,266	254,762,700	917,146	23,404,382	48,269	2,036,063	1,778,733
CS4B Hixon	Compressor Unit 1 - Spey	11,931	130,644,450	470,320	12,001,963	24,753	1,044,110	912,149
CS4B Hixon	Compressor Unit 3 - LM2500	23,266	254,762,700	917,146	23,404,382	48,269	2,036,063	1,778,733
CS5 Australian	Compressor Unit 7 - LM2500	23,266	254,762,700	917,146	23,404,382	48,269	2,036,063	1,778,733
CS6A 150 Mile House	Compressor Unit 1 - SPEY	11,931	130,644,450	470,320	12,001,963	24,753	1,044,110	912,149
CS6A 150 Mile House	Compressor Unit 10 - LM2500GJ-DLE	18,493	202,498,350	728,994	18,602,993	38,366	1,618,367	1,413,827

Station	Compressor Unit	Rated Power (kW)	Gas Compressor Energy Consumption (kWh)	Energy Consumption (GJ/year)	Fuel Volume (m^3)	Scope 1 Emissions (tCO2e/year)	Potential Natural Gas Cost ($)	Carbon Tax Cost ($)
CS6B 93 Mile House	Compressor Unit 2 - Spey	11,931	130,644,450	470,320	12,001,963	24,753	1,044,110	912,149
CS6B 93 Mile House	Unit 10 - PGT 25+ (new)*	30,929	338,672,550	1,219,221	31,112,960	64,167	2,706,671	2,364,585
CS7 Savona	Compressor Unit 10 - LM2500GJ-DLE	18,493	202,498,350	728,994	18,602,993	38,366	1,618,367	1,413,827
CS7 Savona	Compressor Unit 20 - LM2500GJ-DLE	18,493	202,498,350	728,994	18,602,993	38,366	1,618,367	1,413,827
CS8A Kingsvale	Compressor Unit 2 - Spey	11,931	130,644,450	470,320	12,001,963	24,753	1,044,110	912,149
CS8A Kingsvale	Unit 10 - PGT 25+ (new)*	30,929	338,672,550	1,219,221	31,112,960	64,167	2,706,671	2,364,585
CS8B Othello	Compressor Unit 10 - LM2500GJ-DLE	18,493	202,498,350	728,994	18,602,993	38,366	1,618,367	1,413,827
CS16 Sunset Creek	Compressor Unit 1 – Solar Titan 130	15,290	167,425,500	602,732	15,380,942	31,721	1,338,065	1,168,952
CS16 Sunset Creek	Compressor Unit 2 – Solar Titan 250 (New)	22,371	244,962,450	881,865	22,504,059	46,412	1,957,740	1,710,308
Total	**30 Units**	**486,508**	**5,327,262,600**	**19,178,145**	**489,401,664**	**1,009,329**	**42,575,483**	**37,194,526**

APPENDIX G: Electricity Consumption, GHG Emissions and Economic Analysis after Electrification

Station	Compressor Unit	Rated Power (kW)	Electricity Usage (kWh)	Scope 2 emissions (tCO2e/year)	Electricity Cost ($)	Transmission line cost ($)
CSN3 Sikanni Chief	Compressor Unit 1, LM1500	10,567	48,719,432	585	3,645,675	56,000,000
CSN3 Sikanni Chief	Compressor Unit 2, LM1500	10,567	48,719,432	585	3,645,675	56,000,000
CSN4 Cypress	Compressor Unit 1 & 2, LM1500	10,567	48,719,432	585	3,645,675	56,000,000
CSN4 Cypress	Compressor Unit 1, LM1500	10,567	48,719,432	585	3,645,675	56,000,000
CSN4 Cypress	Compressor Unit 10 - Solar Titan 250	22,371	103,142,084	1,238	7,718,122	56,000,000
CSN5 Mackie Creek	Compressor Unit 1, LM1500	10,567	48,719,432	585	3,645,675	16,000,000
CSN5 Mackie Creek	Compressor Unit 2, LM1500	10,567	48,719,432	585	3,645,675	16,000,000
CS2 Willow Flat	Compressor Unit 1, LM 1500	10,567	48,719,432	585	3,645,675	16,000,000
CS2 Willow Flat	Compressor Unit 2, LM1500	10,567	48,719,432	585	3,645,675	16,000,000
CS2 Willow Flat	Compressor Unit 4, LM 1600	14,168	65,321,937	784	4,888,041	16,000,000
CS2B Azouzetta Lake	Compressor Unit 1-Spey	11,931	55,008,189	660	4,116,263	24,000,000
CS2B Azouzetta Lake	Compressor Unit 10 - LM2500GJ-DLE	18,493	85,262,463	1,023	6,380,190	24,000,000
CS3 McLeod Lake	Compressor Unit 5 - LM2500	17,897	82,514,589	990	6,174,567	12,000,000
CS3 McLeod Lake	Compressor Unit 6 - LM1600	14,168	65,321,937	784	4,888,041	12,000,000

Station	Compressor Unit	Rated Power (kW)	Electricity Usage (kWh)	Scope 2 emissions (tCO2e/year)	Electricity Cost ($)	Transmission line cost ($)
CS4A Summit Lake	Compressor Unit 1 - Spey	11,931	55,008,189	660	4,116,263	800,000
CS4A Summit Lake	Compressor Unit 3 - LM2500	23,266	107,268,505	1,287	8,026,902	800,000
CS4B Hixon	Compressor Unit 1 - Spey	11,931	55,008,189	660	4,116,263	20,000,000
CS4B Hixon	Compressor Unit 3 - LM2500	23,266	107,268,505	1,287	8,026,902	20,000,000
CS5 Australian	Compressor Unit 7 - LM2500	23,266	107,268,505	1,287	8,026,902	1,600,000
CS6A 150 Mile House	Compressor Unit 1 - SPEY	11,931	55,008,189	660	4,116,263	8,000,000
CS6A 150 Mile House	Compressor Unit 10 - LM2500GJ-DLE	18,493	85,262,463	1,023	6,380,190	8,000,000
CS6B 93 Mile House	Compressor Unit 2 - Spey	11,931	55,008,189	660	4,116,263	8,000,000
CS6B 93 Mile House	Unit 10 - PGT 25+ (new)*	30,929	142,598,968	1,711	10,670,681	8,000,000
CS7 Savona	Compressor Unit 10 - LM2500GJ-DLE	18,493	85,262,463	1,023	6,380,190	800,000
CS7 Savona	Compressor Unit 20 - LM2500GJ-DLE	18,493	85,262,463	1,023	6,380,190	800,000
CS8A Kingsvale	Compressor Unit 2 - Spey	11,931	55,008,189	660	4,116,263	20,000,000
CS8A Kingsvale	Unit 10 - PGT 25+ (new)*	30,929	142,598,968	1,711	10,670,681	20,000,000

Station	Compressor Unit	Rated Power (kW)	Electricity Usage (kWh)	Scope 2 emissions (tCO2e/year)	Electricity Cost ($)	Transmission line cost ($)
CS8B Othello	Compressor Unit 10 - LM2500GJ-DLE	18,493	85,262,463	1,023	6,380,190	4,000,000
CS16 Sunset Creek	Compressor Unit 1 – Solar Titan 130	15,290	70,494,947	846	5,275,137	16,000,000
CS16 Sunset Creek	Compressor Unit 2 – Solar Titan 250 (New)	22,371	103,142,084	1,238	7,718,122	16,000,000
Total	**30 Units**	**486,508**	**2,243,057,937**	**26,917**	**167,848,025**	**584,800,000**

APPENDIX H: Electricity Unit Cost under Different CBL Usage Percentage

	90% CBL	95% CBL	98% CBL	110% CBL
RS 1823 Tire 1 Rate ($/MWh)	44.90	44.90	44.90	44.90
RS 1823 Tire 2 Rate ($/MWh)	100.60	100.60	100.60	100.60
Demand charge equivalent ($/MWh)	18.01	20.797	22.468	29.15
Average Unit Electricity Cost: RS1823 ($/MWh)	68.49	71.27	72.941	79.63
PST	0.0%	0	0	0
GST	5%	5%	5%	5%
TOTAL Average Unit Electricity Cost - including taxes ($/MWh)	71.91	74.834	76.59	83.61

APPENDIX I: Westcoast Electrification Scenario Analysis

Scenario	**Baseline**	**S1 - Rapid Approach**	**S2 - Steady Approach**	**S3 - Practical Approach**
Compressor count	30	30	17	12
Compressor station count	15	15	11	9
Project life year		25	25	25
GHG Emissions				
Scope 1 emissions - stationary combustion (thousand tCO_2e)	1,000	0	519	378
Scope 1 emissions - Venting/Fugitive Emissions (thousand tCO_2e)	223	223	223	223
Scope 2 emission (thousand tCO_2e)	0	28	13	10
Energy Consumption				
Fuel Gas Consumption (thousand m3)	489,402	-	251,636	306,157
Electricity Demand (MWh)	0	2,243,058	1,089,744	839,858
Economic Analysis				

Scenario	**Baseline**	**S1 - Rapid Approach**	**S2 - Steady Approach**	**S3 - Practical Approach**
Indirect - Fuel offset to shipper (million $/year)		($43)	($21)	($16)
Electricity Cost (million $/year)	0	$168	$82	$63
Carbon Tax (million $/year)	$37	($37)	$18	$14
Maintenance (million $/year)	$24	$6	$14	$17
O & M Cost (million $/year)	**$61**	**$137**	**$113**	**$94**
Capital (million $/year)		**$854**	**$0**	**$0**
Transmission line cost (million $/year)		$556	$402	$58
Substation fix cost (million $/year)		$195	$143	$117
Power Infrastructure cost (million $/year)		$751	$545	$175