Yukon Power Plant Fuel Life Cycle Analysis

Final Report

July 2, 2013

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Life Cycle Results

Acknowledgements

The Yukon Power Plant Fuel Life Cycle Analysis was completed with the guidance and input of a stakeholder working group that included several members from Yukon Energy and the Yukon Conservation Society. ICF Marbek would like to acknowledge the contributions of these organizations for their time and effort as they provided thoughtful feedback throughout the study.

Executive Summary

Yukon Energy Corporation (YEC) wants to understand direct and indirect environmental consequences associated with the use of liquefied natural gas (LNG) for power generation at an electricity generating facility (planned project) versus an equivalently sized diesel-fueled facility in the city of Whitehorse.

ICF Marbek (ICF) has been retained to complete a life cycle assessment (LCA) of the environmental exchanges associated with three alternatives that have been identified. More specifically the environmental exchanges that are the focus of the study include emissions of greenhouse gases, nitrogen oxides (NO_x), sulphur dioxide (SO_2), carbon dioxide (CO) and particulate matter (PM), as well as water consumption.

The full lifecycle, from drilling through full production and processing, transportation of fuel to Whitehorse and combustion to generate electricity has been considered for each alternative studied, which constitutes three pathways from wellhead to transmission line. The study pathways are:

1. Conventional natural gas extraction and processing in the Foothills of Alberta to produce LNG for transportation to Whitehorse and subsequent electricity generation using a natural gas fired engine;
2. Shale (unconventional) gas extraction using hydraulic fracturing in northeastern British Columbia to produce LNG for transportation to Whitehorse and subsequent electricity generation using a natural gas fired engine; and
3. Crude extraction on the North Slope of Alaska, transportation of the crude to a refinery in northwestern Washington to produce diesel fuel, followed by transportation of the diesel to Whitehorse and subsequent electricity generation using a diesel fired engine.

The results of the LCA are presented in the summary table below. All results are presented using an equivalent basis of measure (per megawatt-hour of electricity generated at the YEC facility), which facilitates comparison between the study pathways.

None of the three scenarios studied provides a clear environmental benefit over another in every environmental exchange category studied. While the *Shale Gas* pathway results in the lowest greenhouse gas and air pollutant emissions, the water consumption required in this pathway is three times greater than the next greatest water consuming pathway.

		GHG kg CO_2e/MWh	**NOx** kg NO_x/MWh	**SO_2** kg SO_2/MWh	**CO** kg CO/MWh	**PM** kg PM/MWh	**Water** L/MWh
Shale Gas	Base Case	594.3	2.1	0.2	1.2	0.2	178.2
Conventional Natural Gas	Base Case	679.5	2.3	2.2	1.7	0.7	5.6
Diesel	Base Case	694.8	17.8	1.2	1.2	1.1	52.9

Uncertainty analysis was conducted through variation of key study modeling parameters and consideration of alternative scenarios. In most cases, this analysis showed that the final combustion of fuel is the largest contributing factor in LCA emissions.

Life Cycle Assessment – Background and Definition

Goal and Scope Definition

The objective of the study is to inform YEC and stakeholders about the direct and indirect environmental consequences of adopting the use of natural gas for the purposes of power generation compared to those from using diesel.

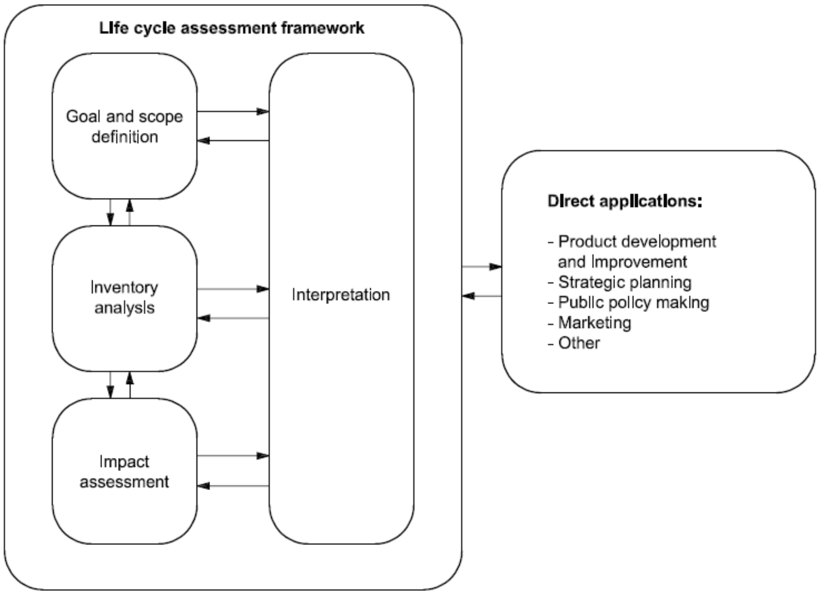
This study used a Life Cycle Assessment (LCA) approach and tools. LCA is a methodological framework for estimating and assessing environmental impacts attributable to the life cycle of a product or service. It considers the activities associated with the extraction, production and transportation of materials, manufacturing of the product or offering of the services, and if applicable, includes the activities associated with the products' distribution, use, or consumption, and end of life (i.e., reuse, recycling, disposal). All those activities lead to environmental impacts attributable to the use of resources and energy and the chemistry of materials used. LCA methodology has several applications; in this analysis, the application of LCA during the process design and development phase of YEC project can improve the overall environmental performance of the services provided.

There are methodological choices that impact the results of an LCA study. Consumption of resources and materials as well as emissions has to be tabulated at each relevant stage/activity of the life cycle. The demand on time and data for the purposes of conducting a complete LCA has to be balanced with the definition of boundaries and unit of analysis relevant to inform the particular goal of the LCA. The life cycle boundaries determine which supply chain activities or life cycle stages – and processes attributable to those stages – are included as well as the location and timeframe considered for the performance of such processes.

Inventory Analysis

In this analysis, the unit of analysis ("functional unit") being used is a megawatt-hour of electricity produced, that is, the total environmental exchanges (emissions of greenhouse gases, air pollutants and water consumption) are presented on an intensity basis (for example, kg sulphur dioxide per MWh of electricity produced). Also, environmental impacts and environmental impact categories of interest have been identified.

Figure 1: Life Cycle Stages



Source: Environmental management — Life cycle assessment — Principles and framework. ISO 14040. Second edition, 2006

Establishing the goal and scope of the analysis ensures that the data collection is focused on the environmental impacts of interest at all relevant stages. A simplified illustration of the environmental impacts associated with the pollutants (Figure 2) includes the inventory data collected in this LCA.

In this study, a simplified or "streamlined" LCA was conducted (Rebitzer et al. 2004). Relevant life cycle stages were defined for natural gas and diesel.

A natural gas life cycle framework proposed by the World Resources Institute (WRI) for the shale gas life cycle was adapted to define all three pathways. Processes and geographical boundaries were defined based on information provided by YEC regarding current and potential supply chain partners.

Data collection for natural gas and diesel life cycles is based on use of energy demand, the most widely used screening indicator in the application of LCA methods. The approach is relevant in this analysis as the environmentally impacts of interest are strongly linked to energy production and consumption processes. For example, "fossil energy use is responsible for 90% of impacts on resource depletion, 70% on acidification, and 65% on global warming" (Braunmiller et al. in Rebitzer et al. 2004). The expected changes in environmental exchanges are modeled based on information provided by YEC regarding power plant technologies and performance for both natural gas and diesel.

Data collection for relevant processes (i.e., processing of natural gas or diesel and power generation) relies upon published mandatory GHG and CAC emissions reports and YEC detailed technical analysis of power generation performance. For other processes, where specific GHG and CAC data were not available, the GHG and CAC are determined by process-based specific energy demand and related air emissions that are estimated by the use of the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model (Argonne National Laboratory GREET_v.12012).

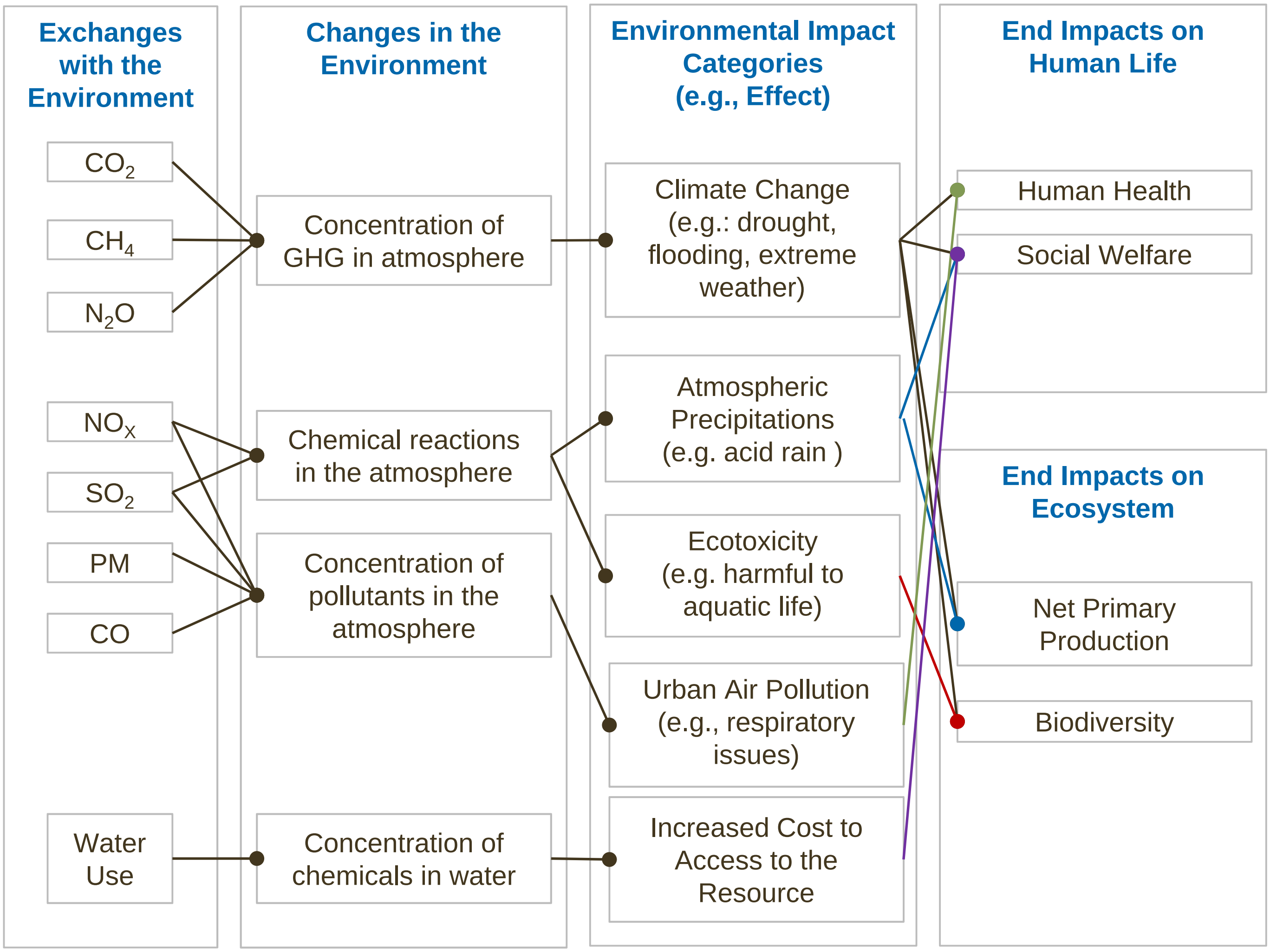
The data collection and emission factor data are considered high quality and represent the performance of the technologies used for power generation, and resource extraction and processing in the region of study. A "traditional" process-based LCA approach for data collection was replaced by actual reported data for the major processes included in each pathway, where actual emissions and water consumption data were available. While the GREET data do not represent direct suppliers data, the model does provide average industry performance in the region of study, and allows for completeness and transparency of the LCA.

Study Parameters

Figure 2 depicts the causality of exchanges with the environment that result as a consequence of the development and use of the industrial processes in the study. This common framework facilitates the comparison of the downstream environmental impacts (including impacts on human life and affected ecosystems).

Use of natural resources and air emissions (collectively, “exchanges with the environment”) results in changes in the environment. It is important to note that some exchanges with the environment, such as water use and emissions of NO_x, SO_2, CO and PM, have localized effects, whereas other exchanges with the environment, specifically emissions of GHGs, have a global effect because they dissipate throughout the global atmosphere. The following pages provide further background regarding the specific changes to the environment and resulting environmental impacts of each of the exchanges with the environment that are included within the focus of this study.

Figure 2: Environmental Exchanges and, Impact Categories and End Impacts



Exchanges with the Environment – Greenhouse Gasses

Greenhouse gases (GHGs) includes gases that exist in the atmosphere and absorb infrared radiation. The most commonly known GHGs (and the only ones relevant to this LCA) include carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O), which are byproducts of fossil fuel combustion. Venting and fugitive emissions (leaks) of methane are also an important consideration in this analysis because natural gas is primarily comprised of methane.

Manufactured gases, including sulphur hexafluoride (SF_6) which is used in high voltage switchgear, and Hydrofluorocarbons (HFCs) which are used in cooling systems, are potent GHGs. SF_6 is considered in the electricity consumed from the electricity grid within the study. Other manufactured gases are not considered because they do not typically exist within the processes associated with the study pathways.

For the purposes of calculating and reporting total emissions, all GHGs are related to CO_2 using a factor that is specific to each gas. This factor, known as the "Global Warming Potential" (GWP) is based upon the relative global warming effect of each gas on a 100-year timescale in comparison to CO_2. When all GHGs are presented on a common basis, the common unit is known as the carbon dioxide equivalent (CO_2e) (IPCC 2005). The GWPs are presented in Figure 3.

The most significant sources of GHG emissions in the LCA result from fossil fuel combustion (natural gas and diesel), fuel consumed to produce electricity (coal, natural gas and diesel), and fugitive emissions of natural gas.

Impacts

Human health, terrestrial and aquatic ecological systems, and socio-economic systems (e.g., agriculture, forestry, fisheries and water resources) are all vital to human development and well-being and are all sensitive to both the magnitude and the rate of climate change (IPCC 1995). Increased concentration of GHG in the atmosphere can lead to climate change (e.g., drought, flooding, extreme weather) which has potential impacts on both humans (e.g., human health and social welfare) and ecosystems (e.g., biodiversity, ecosystem services) (Franco et al. 2011).

Figure 3: IPCC TEAP 2005 Global Warming Potentials for a 100 Years Horizon

Greenhouse Gas (GHG)	Global Warming Potential
CO_2	1
CH_4	25
N_2O	298
SF_6	22,800

Exchanges with the Environment – Air Contaminants

Nitrogen oxide (NO_x) refers to NO and NO_2, which are both formed when nitrogen and oxygen molecules undergo an endothermic reaction during combustion at high temperature (making its production equipment specific).

Sulphur oxide (SO_x) refers to a group of compounds including sulphur dioxide (SO_2). SO_2 is produced in typical hydrocarbon combustion reactions where sulphur is present in the fuel. Since SO_2 is the predominant sulphur containing by-product of these reactions, this report focuses on the emissions of SO_2 as opposed to the greater category of "SO_x".

Carbon monoxide (CO) is found in combustion exhaust gases when the reaction of CO to CO_2 cannot proceed if there is a lack of oxygen in the combustion reaction, the temperature of combustion is too low or the residence time in the reaction chamber is too short.

Emissions of particulate matter (PM) may be traced to many sources; of relevance to this study are the noncombustible trace components of fuel (natural gas, diesel, coal, etc.) and lubricating fuels (used in mobile and stationary engines).

The significant sources of air contaminants in this study are all related to the combustion of hydrocarbons. The specific processes involved include the natural gas or diesel electricity generator at the YEC site in Whitehorse, the processes involved with natural gas processing and oil refining, the transportation of raw crude, refined diesel and liquefied natural gas, and the various generators producing electricity on the electricity grids connected to the processing and refining facilities.

Impacts

The air contaminants described above (NO_x, SO_2, CO and PM) do not disperse globally in the atmosphere in the way that GHGs do, so local dispersion is particularly important. Increased concentration of NO_x and SO_x in a local air shed air has environmental consequences. Both chemicals, when dissolved in the atmosphere, react with the water to form components of acid rain (HNO_3, nitric acid and H_2SO_4, sulfuric acid). In ecosystems in equilibrium, HNO_3 allows the formation of nitrate that is useful to growing plants; however, increased concentrations of the chemicals in the air disturbs the equilibrium, creating acid rain that can be harmful for plants, aquatic animals, and infrastructure. Also, these chemicals are a risk for human health.

NO_x reacts with volatile organic compounds (VOC) in the presence of sunlight to form photochemical smog that has adverse human health effects such as damage of lung tissue and reduction of lung function. The impact characterization of such gases has to be developed using models that account for temporal and spatial resolution (i.e., location and time of emissions, mode of release to the atmosphere, and sensitivity of the affected environment in terms of time and space) (Rebitzer et al. 2004). Generic characterization factors exist; however, they may not be representative of a specific geographic area.

CO and PM emissions in significant concentrations lead to air pollution that has been linked to human health impacts such as respiratory issues.

Exchanges with the Environment – Water Consumption

Water is required for several of the processes included in the study including hydraulic fracturing, natural gas well drilling, crude oil well stimulation, and to produce steam and provide cooling in the crude refining process. Each of these processes utilize local water supplies and therefore, the impact of water consumption is relatively localized.

The process requiring the greatest water consumption of the three pathways in this study is hydraulic fracturing. The purpose of this process is to release unconventional hydrocarbon reserves (in this case, natural gas) that are trapped in rock so that the gas flows readily into the well bore. The process uses a base fluid (water, synthetic oils, or liquefied petroleum gas) with chemical additives to transmit pressure and create or open cracks in the rock as illustrated in Figure 4. The water volume required depends on the type of reservoir and the required treatment technology to produce the gas. The volume of water used varies greatly depending on the formation the number of stages and fractures required. Industry is working to improve recycling rates and to use alternate sources of water such as saline groundwater and reclaimed wastewater (B.C. Oil & Gas Commission, 2010).

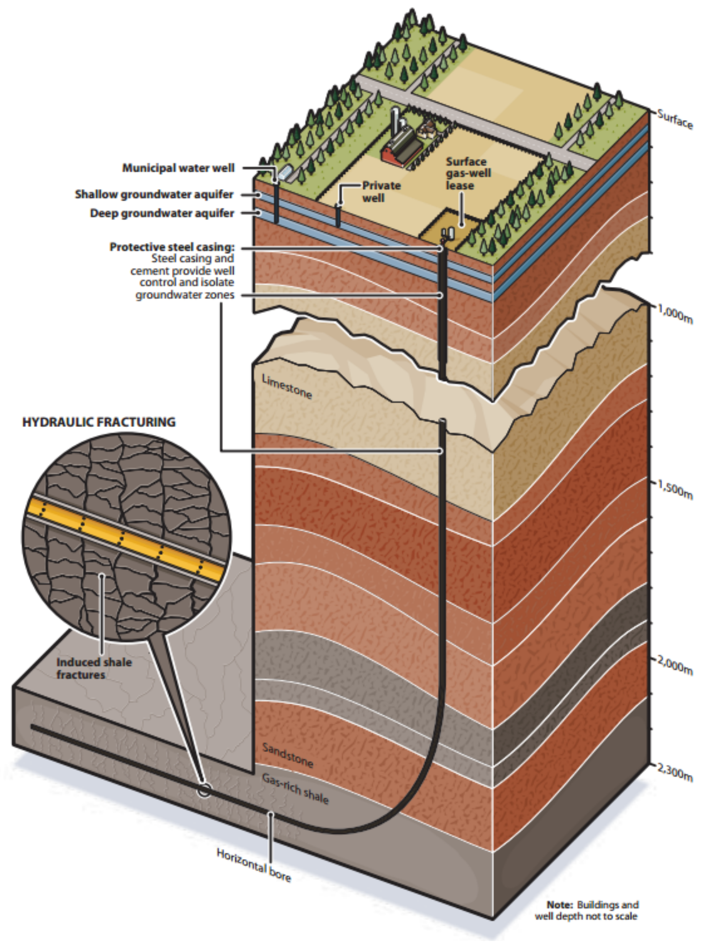
The disposal of produced water is heavily regulated through legislation. Waste water or produced water (the natural salt water found in oil and gas reservoirs that is extracted along with the targeted oil and gas resource) from oil and gas extraction activities follows a number of different paths. All fracture return water (the water that returns to the surface after hydraulic fracturing for unconventional gas development) is either recycled and used for further hydraulic fracturing, or is disposed of by injection into deep subsurface formations, through a water disposal well.

Regulation require that produced water and fracture return water are not introduced into surface waters such as lakes and streams, and are not introduced into near surface aquifers that are used for potable water supply. (B.C. Oil & Gas Commission 2010).

Impacts

Water consumption results in a change of water availability for other environmental purposes or other human activities. Large scale water consumption can lead to ecosystem impacts and changes in the concentration of chemicals (natural and otherwise) in water sources.

Figure 4: Hydraulic Fracturing Process



Source: Canadian Association of Petroleum Producers

Pathways

YEC is considering three alternatives for the new electricity generation facility. Each of these three alternatives involves a different source of fuel for the generator and therefore, the study has been designed to analyze the environmental impacts along the full lifecycle of the fuel from the wellhead to the electricity generator, including the combustion of the fuel and generation of electricity. Each alternative or *Pathway* is described briefly below and in greater detail on the following pages.

Each of the three pathways are shown in Figure 5. Transportation related portion of each pathway are represented by lines (lines are shown for illustrative purposes; actual course may vary from that shown in the figure).

Figure 5: LCA Pathways

The *Conventional Natural* Gas pathway (shown in red) involves drilling and production of raw natural gas from the foothills of Alberta, processing and liquefaction of natural gas at a gas plant west of Calgary, transportation of liquefied natural gas (LNG) by truck to Whitehorse, regasification of the LNG and combustion to generate electricity at YEC's facility in Whitehorse.

The *Shale Gas* pathway (also referred to as the unconventional natural gas pathway) involves drilling and hydraulic fracturing in the Horn River basin area of northeastern British Columbia, natural gas processing and liquefaction at a facility in the local area, transportation of LNG by truck to Whitehorse, regasification of the LNG and combustion to generate electricity at YEC's facility in Whitehorse.

The *Diesel* pathway begins with crude oil extraction on the North Slope of Alaska, pipeline transportation south across Alaska to Valdez where it is loaded onto tankers for transportation to a refinery in northwestern Washington, refining of the crude into diesel, transportation by tanker from Washington to Juneau, Alaska, ferry transportation to Skagway, Alaska, truck transportation of the diesel to Whitehorse and combustion to generate electricity at YEC's facility in Whitehorse.

Figures 6, 7 and 8 on the following pages illustrate the processes within each pathway. The processes are grouped by the categories that are used to present the total exchanges with the environment (i.e. emissions and water consumption). The dashed lines on these figures represent the study boundary selected for the LCA.

Figure 9, which follows the process diagrams, provides a description of each process and an indication of the processes that are included (marked with "X") within each pathway. Processes that are excluded from the boundary were determined to be insignificant to the overall lifecycle of each pathway.

Figure 6: Shale Gas (Unconventional Natural Gas) to LNG to Power Generation Pathway

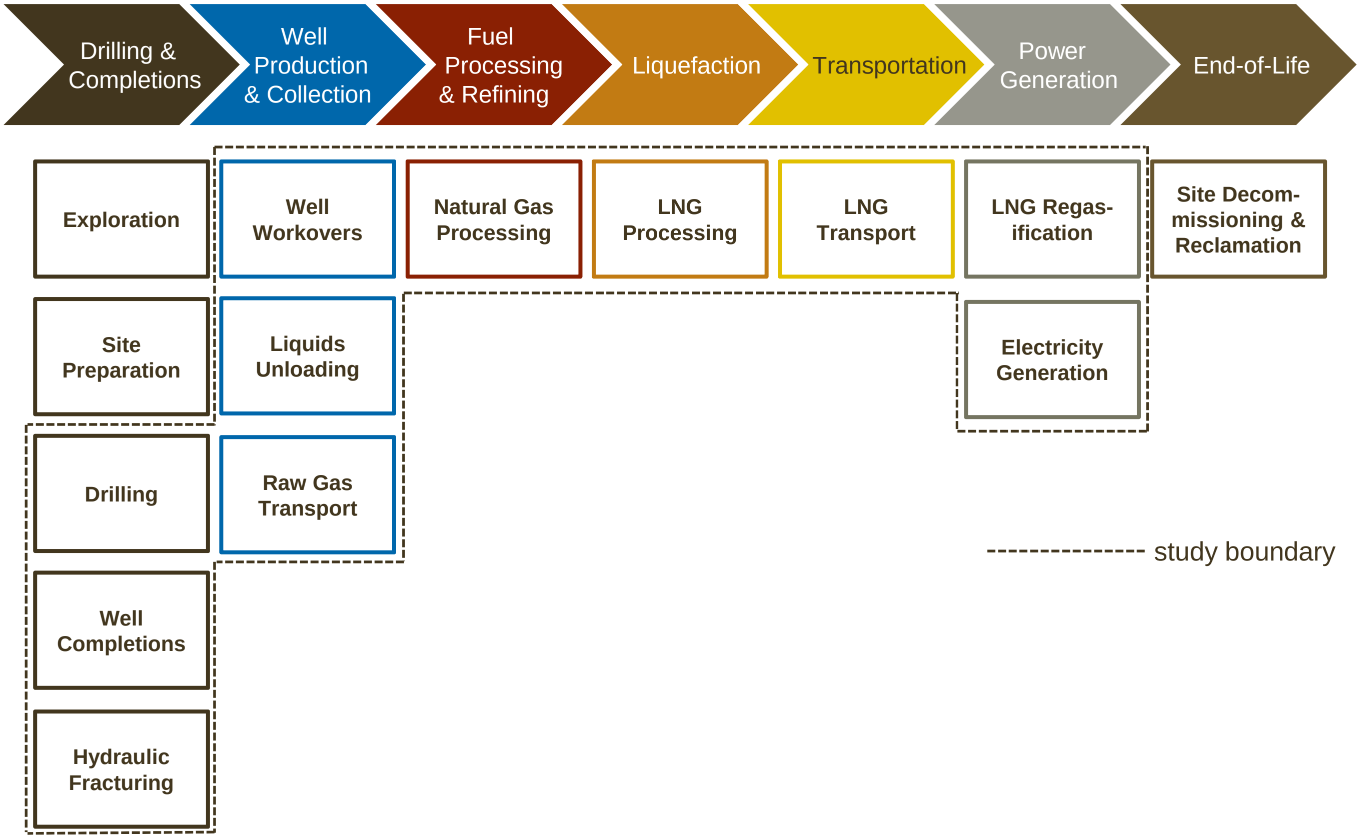
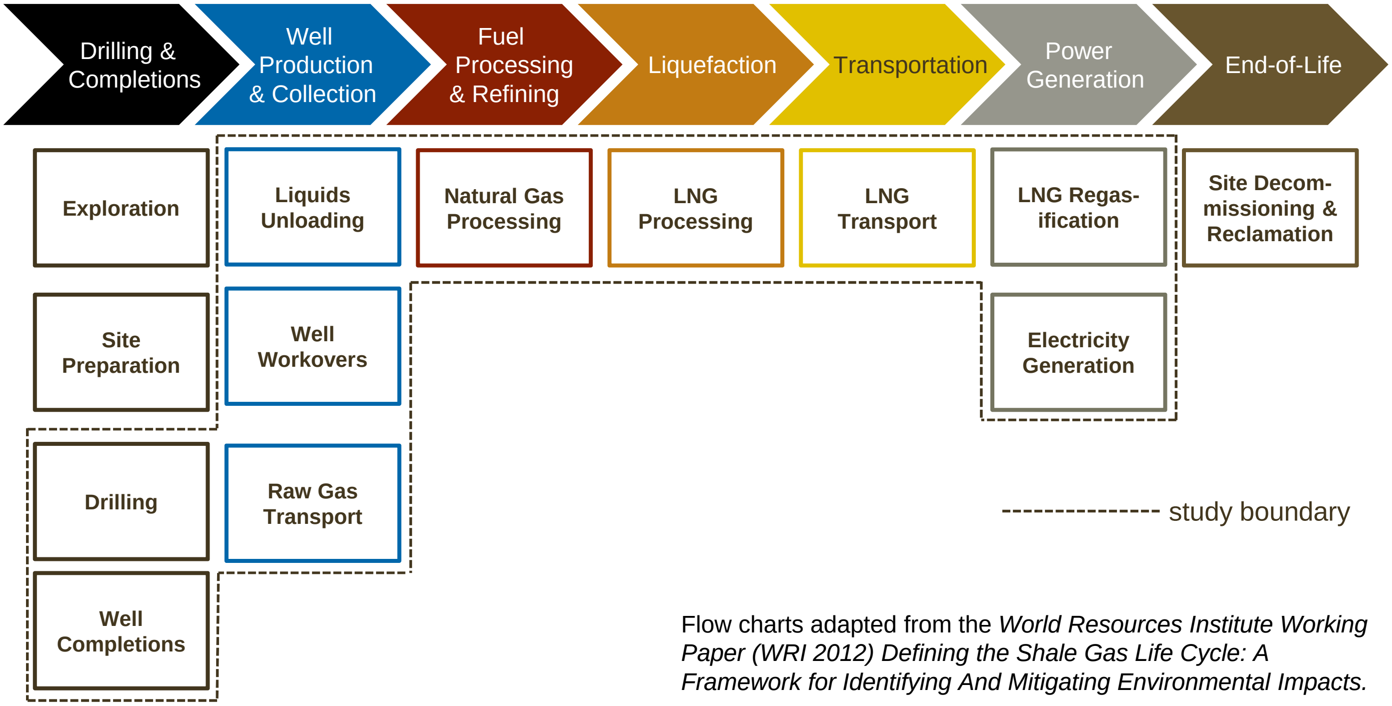


Figure 7: Conventional Natural Gas Pathway



Flow charts adapted from the *World Resources Institute Working Paper (WRI 2012) Defining the Shale Gas Life Cycle: A Framework for Identifying And Mitigating Environmental Impacts.*

Figure 8: Diesel Pathway

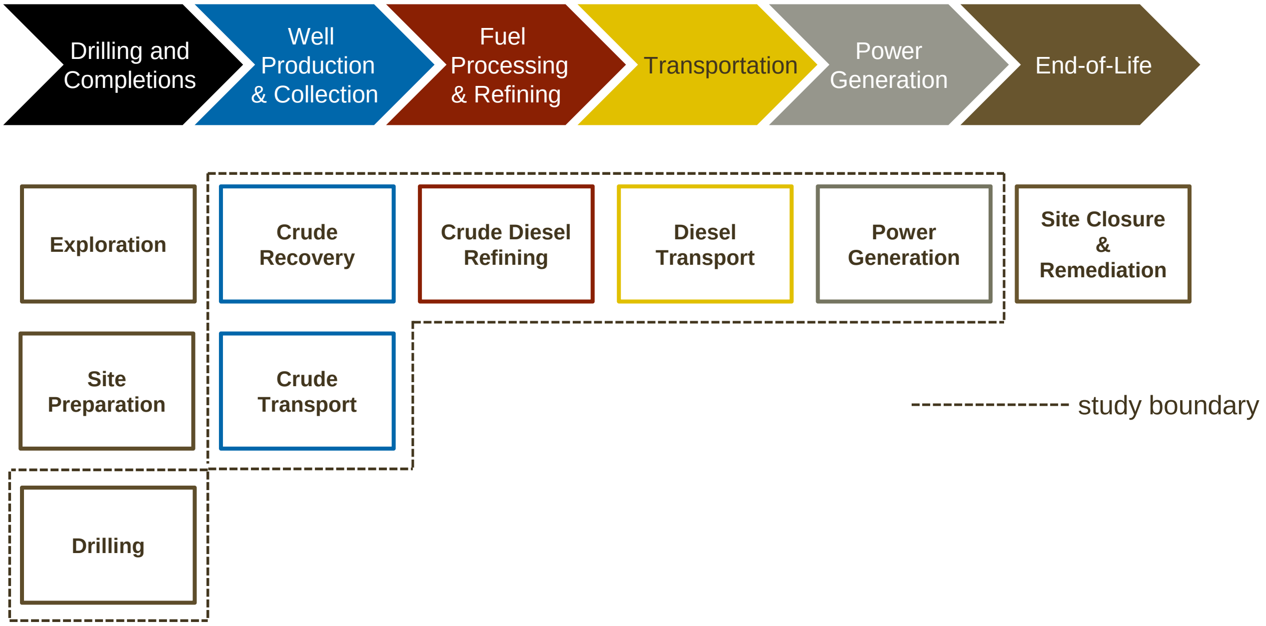


Figure 9: Pathway Processes

Process	Description	Shale Gas	Conv. NG	Diesel
Exploration	This process includes geological surveys, passive seismic surveys, seismic reflection surveys, and exploration well drilling.			
Site Preparation	Sites that have been selected for drilling and subsequent production must be prepared. This includes clearing the well pad area and construction of temporary structures.			
Drilling	A wellbore (hole) is drilled with a drilling rig while drilling mud (composed of a mixture of chemicals, fluids and solids) is pumped down inside the hole to cool the drill bit, lift cut rock to the surface and provide stabilization of the rock walls. Once the hole has been drilled, section of casing (pipe) are inserted in the hole and cement may be placed between the outside of the casing and the wellbore. Drilling was assumed to be completed with diesel fueled equipment in Alberta and natural gas fueled equipment in B.C. according to industry experts.	X	X	X
Well Completions	After the well has been drilled, the wellbore and reservoir near the well are cleaned by producing the well to pits or tanks where sand, cuttings and other reservoir fluids are collected for disposal. Perforations (small holes) are drilled in the well casing in the production zone, to provide a path for flow through the casing. The area above the production zone of the well closed off and connected to the surface with a smaller diameter pipe. In preparation for the production phase, the well is fitted with a production rig and ancillary equipment is installed on the site.	X	X	
Hydraulic Fracturing	Large quantities of water mixed with sand and chemicals are injected at high pressure into natural occurring cracks and faults in the production zone. This technique creates fractures that provide a pathway for trapped natural gas to reach the wellbore.	X		

Figure 9 (continued): Pathway Processes

Process	Description	Shale Gas	Conv. NG	Diesel
Crude Recovery	Extraction of crude in the production phase considered the use of the Watering-Alternating-Gas (WAG) enhanced gas oil recovery technique, which uses injection of produced gas and/or water to stimulate production. Crude recovery also includes local venting and/or flaring of produced gas.			X
Liquids Unloading	Water and other liquids builds up in conventional natural gas wells over time. Removal of these liquids through this procedure improves the production of the well. Through the process, some natural gas may be released from the well and may be captured and flared or vented.	X	X	
Well Workovers	This is a process to repair damage that may occur to the wellbore and replace equipment that has been placed downhole, inside the wellbore. This intermittent process may also release some natural gas, which may be captured and flared or vented.	X	X	
Raw Gas Transport	Gas produced at the well is collected in gas gathering pipelines and shipped to a gas processing facility. In both natural gas study pathways, compressors are driven by engines that use raw natural gas. Fugitive emissions (leaks) may occur along the gathering pipeline system.	X	X	
Crude Transport	Crude produced at the wells is collected and pumped through oil pipelines. The crude involved in the *Diesel* pathway within the study is pumped using electric-driven engines. Crude is loaded onto a tanker and shipped to the crude refinery for processing.			X
Natural Gas Processing	Raw natural gas processing includes several processes that remove liquids and undesirable gases (including carbon dioxide, sulphur and other trace gases), which requires significant quantities of heat and electricity. Tail gases from sulphur processing are incinerated. These facilities utilize flaring to reduce line and equipment gas pressure, occurs only intermittently in upset conditions and plant shut-downs. The source of electricity for both natural gas pathways is the provincial interconnected electricity grid. Emissions associated with this electricity were approximated by considering the current generation mix within each province (see the next section for a more detailed description). Processed natural gas is compressed and shipped in gas transmission systems. In both natural gas pathways in the study, the next process, is natural gas liquefaction, which also involves significant compression.	X	X	
Crude Diesel Refining	Crude oil is a mixture of hydrocarbons that is distilled to separate key components used to make products such as gasoline, jet fuel and diesel oil, and processed through several stages to remove impurities. Some components of the crude oil contain hydrocarbons that are too big to be used as fuels, and these are "cracked" to make the hydrocarbons smaller using other processes. Crude refining requires energy inputs and often low value hydrocarbons are burned to produce that energy. A deep conversion refinery with Delayed Coking and Fluid Catalytic Cracking technologies was considered.			X
LNG Processing (Liquefaction)	Processed natural gas is liquefied through a process that involves compression and refrigeration. These processes require a significant quantity of electricity to drive compression equipment.	X	X	

Figure 9 (continued): Pathway Processes

Process	Description	Shale Gas	Conv. NG	Diesel
LNG Transport	In both natural gas pathways in the study, Liquefied Natural Gas (LNG) is loaded onto transport trucks and subsequently hauled over land to the end-use facility in Whitehorse, Yukon. LNG is unloaded into temporary storage tanks where it is held in a liquid state until it is needed.	X	X	
Diesel Transport	Refined diesel is transported from the refinery to the end-use facility in Whitehorse, Yukon. In the *Diesel* pathway in this study, this involves a tanker between Washington state and Juneau, Alaska, a ferry from Juneau to Skagway, Alaska, and a transport truck from Skagway to Whitehorse, Yukon. Diesel is stored at the YEC site until it is needed for electricity generation.			X
LNG Regasification	LNG is vapourized (changed from liquid to gas) through a controlled process that requires heat input. Waste heat from the electricity generation facility is used for this purpose. When the electricity generation facility is not operating, a small quantity of the LNG may vapourize on its own (known as boil-off gas). This gas may be used locally in heating equipment, flared or vented. In both natural gas pathways in this study, this so-called boil-off gas is flared.	X	X	
Power Generation	An engine combusts natural gas or diesel (depending on the pathway) and mechanically drives a turbine, which generates electricity.	X	X	X
Site closure and remediation	The well site, natural gas processing facility and electricity generation facility will reach their end of useful life and require processes to remove equipment and remediate the sites.			

Grid-Sourced Electricity

A generation weighted average emission factor was developed for grid-sourced electricity consumption by considering the current electricity generation mix for each province/state (shown in Figure 10, below). This electricity mix will change through the course of the lifetime of the new YEC generation station. Most notably, Alberta's heavy reliance on coal fired electricity generation will decline significantly in the 2022 – 2028 timeframe as federal coal greenhouse gas performance standards force the retirement of coal facilities that reach their normal end of life. The result will be a significant decline in the life cycle emissions of all emissions (greenhouse gases and air pollutants).

Figure 10: Current Provincial/State Electricity Generation Mixes

	Alberta	B.C.	Alaska
Coal	55%	0%	9%
Natural Gas Utility Boiler	36%	6%	56%
Oil	0%	0.1%	14%
Biomass	3%	9%	0%
Hydro	3%	84%	20%
Other Renewables	3%	0.2%	1%

Calculating Life Cycle Exchanges with the Environment

The total life cycle exchanges with the environment (greenhouse gases, air pollutants and water consumption) was achieve by calculating the exchanges with the environment for each process defined within the study boundary for each pathway. Where historical, facility-specific data was available, it was prioritized over more general industry-based emission factors.

The following list provides a general overview of the calculation methodology used to calculate emissions for each pathway process:

Natural gas and crude drilling and hydraulic fracturing: emission factors derived from industry data on a well basis.

Liquids unloading, well workovers, crude recovery: emission factors derived from industry data for typical emissions and water consumption on a volumetric basis.

Natural gas processing: on-site emissions based on actual reported emissions to Environment Canada and prorated by publicly declared processing volumes. Grid-sourced electricity consumption was estimated based on processing plant throughput and Environment Canada grid emission factors were applied.

Refinery processing: on-site emissions based on actual reported emissions to the U.S. Environmental Protection Agency and prorated by publicly reported processing volumes for diesel and gasoline (attributed on an equivalent energy basis).

Diesel fueled trucking, tanker and ferry: emission factors and distances.

Upstream lifecycle emissions for diesel, electricity, natural gas – calculated within the model or estimated by the use of the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model (Argonne National Laboratory GREET_v.12012)

Electricity production at the YEC facility in Whitehorse: Manufacturer specifications for specific engines.

Results – Exchanges with the Environment

The total lifecycle emissions for each exchange with the environment studied are presented on the following pages. Sensitivity analysis of key study variable follows these results.

Greenhouse Gas Emissions

GHG emissions are dominated by end-use combustion accounting for 79%, 68% and 92% of the LCA emissions for the *Shale Gas, Conventional Natural Gas*, and *Diesel* pathways respectively (Figure 11). Emissions from diesel combustion are 35% greater than natural gas combustion. Electricity sourced from the Alberta grid also plays a significant role in the LCA emissions of the *Conventional Natural Gas* pathway. Boil-off gas emissions are insignificant, accounting for less than 0.1% of total LCA emissions (natural gas pathways).

The differences in "Liquefaction" emissions between the natural gas pathways are due to the difference in emissions associated with grid-sourced electricity from Alberta (*Conventional Natural Gas*) and local natural gas-fired processes *(Shale Gas).*

The difference in the "Fuel Processing" category of the natural gas pathways results from differing electricity emission factors between British Columbia and Alberta, offset somewhat by a greater concentration of CO_2 in raw gas in the studied shale gas formation, which requires more electricity to remove through the amine processes at the processing facility.

Figure 11: Greenhouse Gas Emissions (kg CO_2e/MWh)

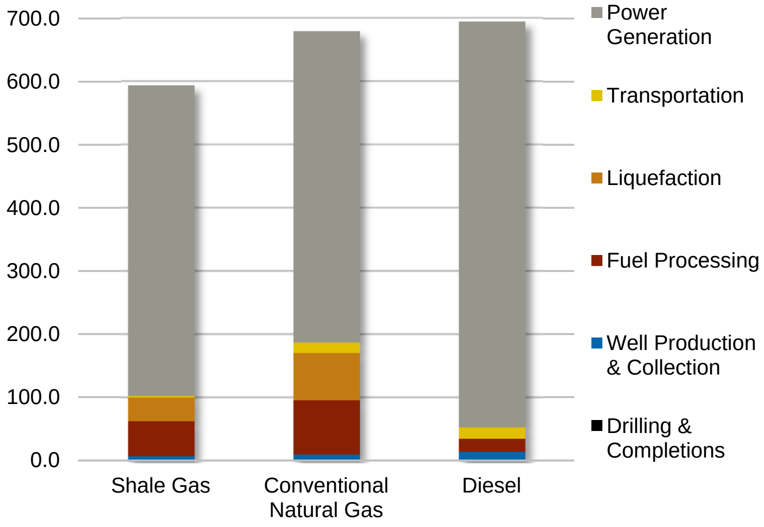
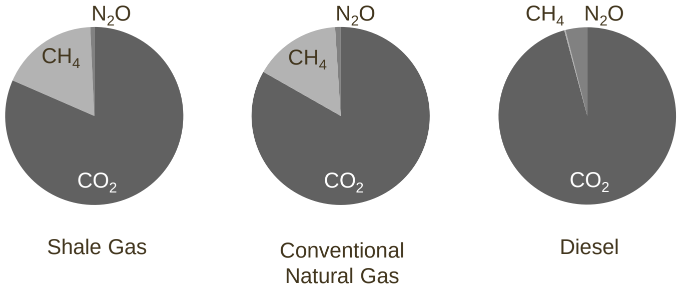


Figure 12: Greenhouse Gases (CO_2e)



The proportional share of each greenhouse gas is shown in terms of CO_2 equivalent in Figure 12.

The vast majority of the CH_4 emitted in the *Shale Gas* and *Conventional Natural Gas* pathways (99% and 96%, respectively) occurs at the YEC generator. The proposed lean burn engine is tuned to reduce NO_x, which results in greater CH_4 emissions. Adjusting the performance of the generator could have a significant impact on overall GHG emissions.

Natural gas that is released during the drilling, well completions and well workover (well maintenance) processes, as well as fugitive emissions (leaks) that occur in the well head and pipelines, have all been included in this analysis. The quantity of methane released through these processes was estimated based on studies that have been conducted by the U.S. Environmental Protection Agency. The actual quantity of methane released through these processes will depend upon the specific equipment and maintenance practices implemented within each pathway as well as the standards imposed within the jurisdiction at the time of drilling and production activity.

Based on the most recently available information available, the quantity of any potential migration of raw gas (methane) from the subsurface reservoir to the surface/atmosphere has not been identified as an issue. Therefore, this potential source of methane emissions has not been estimated within the scope of the life cycle analysis.

The methane emissions from each life cycle category are presented in Figure 13.

Figure 13: Methane Emissions by Pathway Category (kg/MWh)

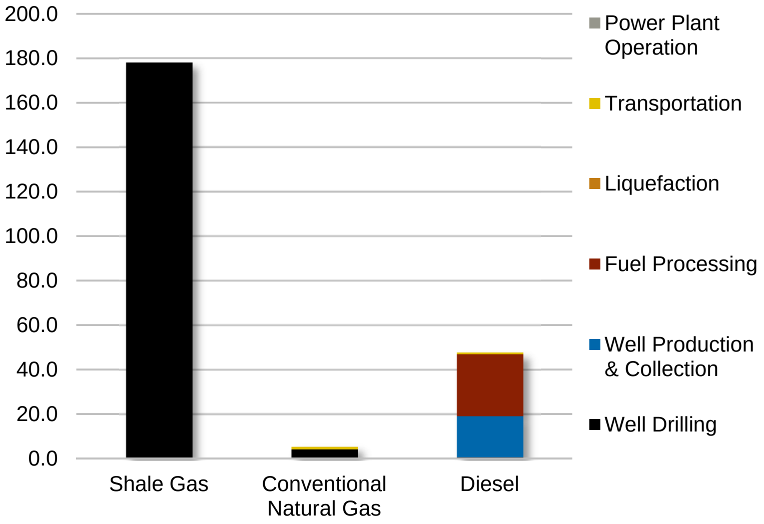
	Drilling & Completions	Well Production & Collection	Fuel Processing & Refining	Liquefaction	Transportation	Power Generation	**TOTAL**
Shale Gas	0.01	0.02	0.01	<0.01	<0.01	4.18	**4.22**
Conventional Natural Gas	<0.01	0.03	0.04	<0.01	0.03	4.18	**4.28**
Diesel	<0.01	0.02	<0.01	N/A	<0.01	0.03	**0.06**

Water Consumption

Hydraulic fracturing accounts for the greatest water consumption within any of the three pathways studied, accounting for 92% of the water consumed in the “Well Drilling” category in the *Shale Gas* pathway (the remaining 8% is used in the actual drilling process).

B.C. Oil & Gas Commission states that water required for hydraulic fracturing in Horn River area is typically, 30,000 – 100,000 m^3 per well. The modeled value is 80,000 m^3 per well as a conservative estimate (based on industry expert feedback). Sensitivity analysis was performed on this value (see “Sensitivity Analysis” section later in this report.

Figure 14: Water Consumption (L/MWh)



Results presented in Figure 14 detail water usage (L) per MWh of electricity generated.

It is important to note that during the hydraulic fracturing process, typically 30% of the injected water is recovered through “flow back”. Industry has been improving methodologies for recycling this water for use in subsequent fracturing events. The B.C. Oil & Gas Commission reports that flowback recycling rates of 45% are currently typical. Given the significant uncertainty related to water used for hydraulic fracturing, recycled volumes have not been considered in the base case LCA model; however, the sensitivity analysis includes consideration for recycled volumes.

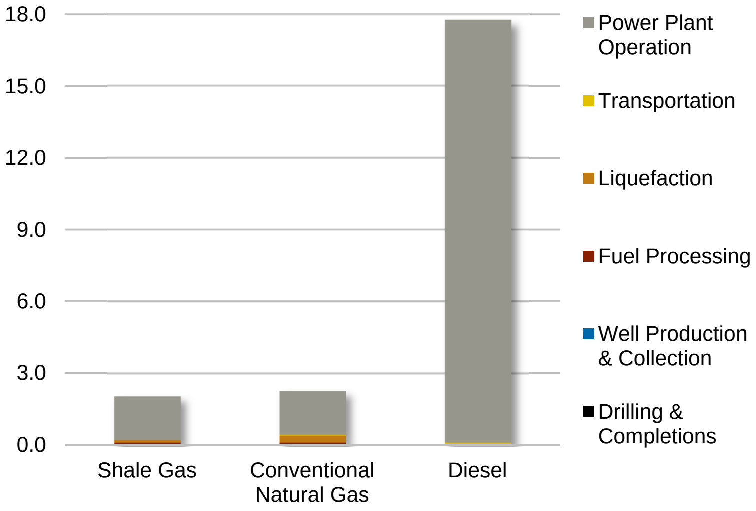
Beyond drilling and fracturing, water consumption occurs in the *Diesel* pathway in several areas including injection of water in crude extraction process and water consumption at the refinery primarily for producing process steam and for cooling.

Nitrogen Oxides (NO_x) Emissions

Lifecycle emissions of nitrogen oxides (NO_x) are predominantly dependent upon the technology used for electricity generation. The proposed diesel generator does not include NO_x control systems, while the proposed natural gas generator does, which accounts for the difference between the emissions shown in the "Power Plant Operation" category.

NO_x control equipment, like most emissions controls equipment, affects the efficiency of the overall system, which causes an increase in the intensity of other emissions. For example, tuning an air-fuel controller to reduce NO_x emissions reduces the efficiency of the engine and increases methane emissions resulting in an increase in GHG emissions per megawatt-hour generated.

Figure 15: Nitrogen Oxides Emissions (kg NO_x/MWh)



For comparison, the U.S. Environmental Protection Agency's published NO_x emission factors for *uncontrolled* natural gas and diesel engines emissions are 4.08 lb/MMBtu and 4.41 lb/MMBtu respectively.

Grid sourced electricity is a significant contributor to NO_x emissions, which explains the large proportion of emissions in the "Fuel Processing" and "Liquefaction" processes of the *Conventional Natural Gas* pathway.

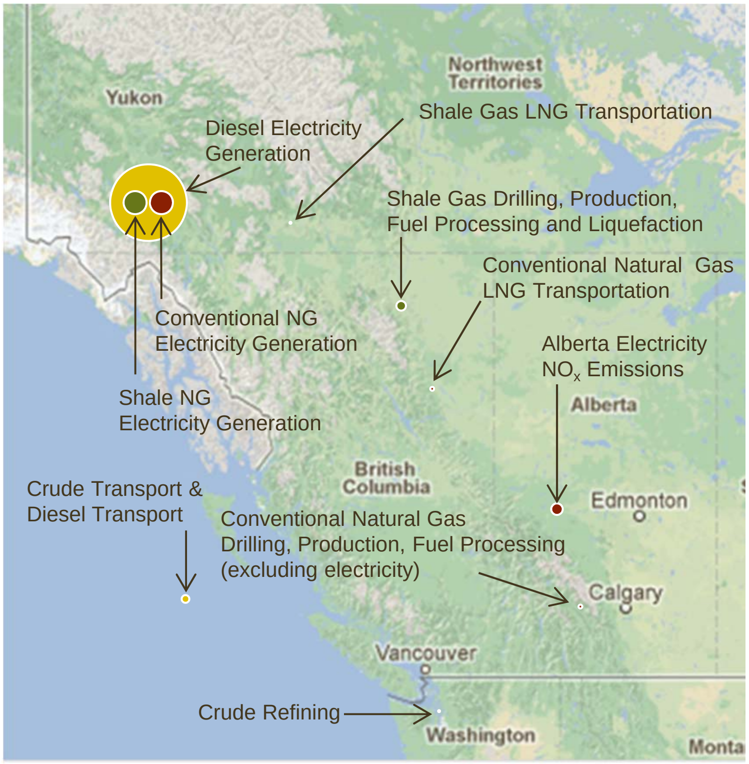
NO_x controls are typically not used for mobile diesel combustion (heavy trucks and tankers), which results in significant emissions related to transportation (and collection for the *Diesel* pathway).

Emissions of nitrogen oxides disperse in the local air shed (as opposed to global dispersion like is the case for greenhouse gases). The impacts of NO_x emissions also occur near the source of emission. Therefore, the magnitude of NO_x emissions should be considered at the local level.

The relative size of each bubble in Figure 16 illustrates the magnitude of NO_x emissions at the emission location. As can be seen in the figure, most emissions in each of the three lifecycles occurs at the YEC generating station in Whitehorse.

Note that some emissions (transportation and grid sourced electricity emissions) occur across a large geographic area, but are summarized at a single point for illustrative purposes in the figure. Also note that the size of the bubbles *do not* represent the dispersion of emissions, only the magnitude of emissions.

Figure 16: Relative NO_x Lifecycle Emissions



Sulphur Dioxide (SO_2) Emissions

Sulphur dioxide emissions depend upon the concentration of sulphur in the fuel being combusted. The "Fuel Processing" category within the *Conventional Natural Gas* pathway has a significant magnitude of SO_2 emissions as a result of a high concentration of hydrogen sulphide H_2S in the raw natural gas. H_2S is removed from the natural gas stream and processed in a sulphur plant; however, a very low concentration of H_2S remains in the waste gas stream from the sulphur plant and must be incinerated, resulting in the formation of SO_2.

The H_2S concentration of the raw shale gas is lower than that of the conventional gas, but still leads to a significant source of SO_2 emissions in the *Shale Gas* pathway.

The SO_2 emissions in the "Liquefaction" category (and a portion of the SO_2 emissions in the "Fuel Processing" category) of the *Conventional Natural Gas* pathway are a result of consumption of grid electricity in Alberta (which is currently predominantly coal and natural gas generated).

Diesel fuel contains sulphur, which results in SO_2 emissions shown in the "Power Plant Operations" category of the *Diesel* pathway.

Processed natural gas contains only trace amounts of H_2S and therefore, emissions of SO_2 during natural gas combustion at the YEC generating facility comprise a very small proportion of the lifecycle SO_2 emissions.

Figure 17: Sulphur Dioxide Emissions (kg SO_2/MWh)

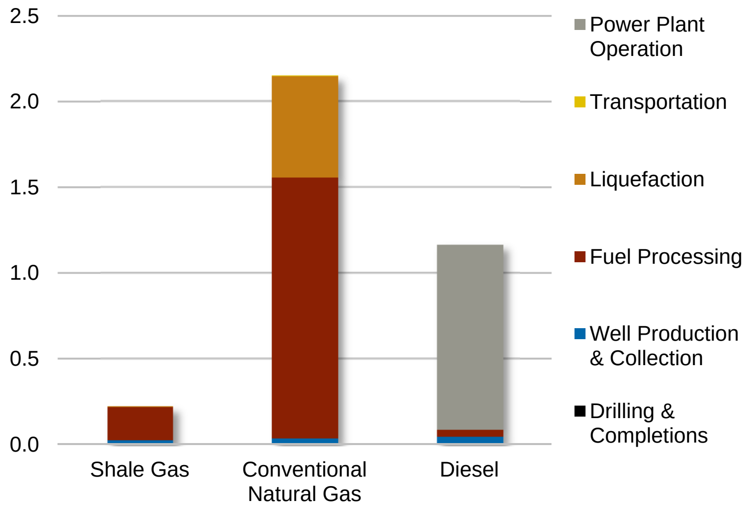


Figure 18: Relative SO_2 Lifecycle Emissions

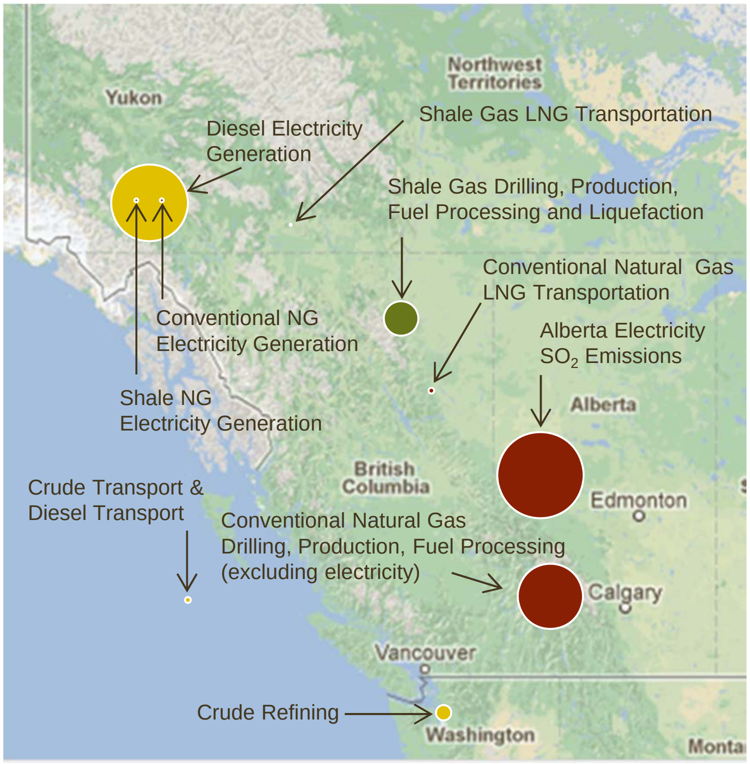


Figure 18 shows the relative magnitude of SO_2 emissions at the point of emissions. Note that some emission (transportation and grid sourced electricity emissions) occur across a large geographic area, but are summarized at a single point for illustrative purposes in the figure. Also note that the size of the bubbles *do not* represent the dispersion of emissions, only the magnitude of emissions.

Carbon Monoxide (CO) Emissions

Carbon monoxide emissions are the product of incomplete combustion.

Carbon monoxide emissions of natural gas and diesel reciprocating engines are in the same range, which explains similar emissions in each of the three "Power Plant Operation" categories of the three pathways.

Electricity generation facilities in Alberta produce a significant quantity of carbon monoxide. The "Liquefaction" category in the *Conventional Natural Gas* pathway is a significant consumer of electricity and therefore, an indirect emitter of carbon monoxide.

Figure 20 shows the relative magnitude of CO emissions at the point of emission. Note that some emissions (transportation and grid sourced electricity emissions) occur across a large geographic area, but are summarized at a single point for illustrative purposes in the figure. Also note that the size of the bubbles *do not* represent the dispersion of emissions, only the magnitude of emissions.

Figure 19: Carbon Monoxide Emissions (kg CO/MWh)

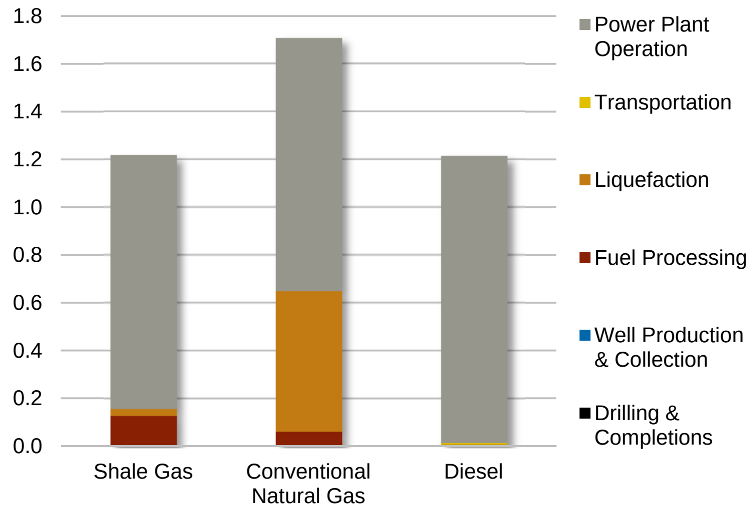
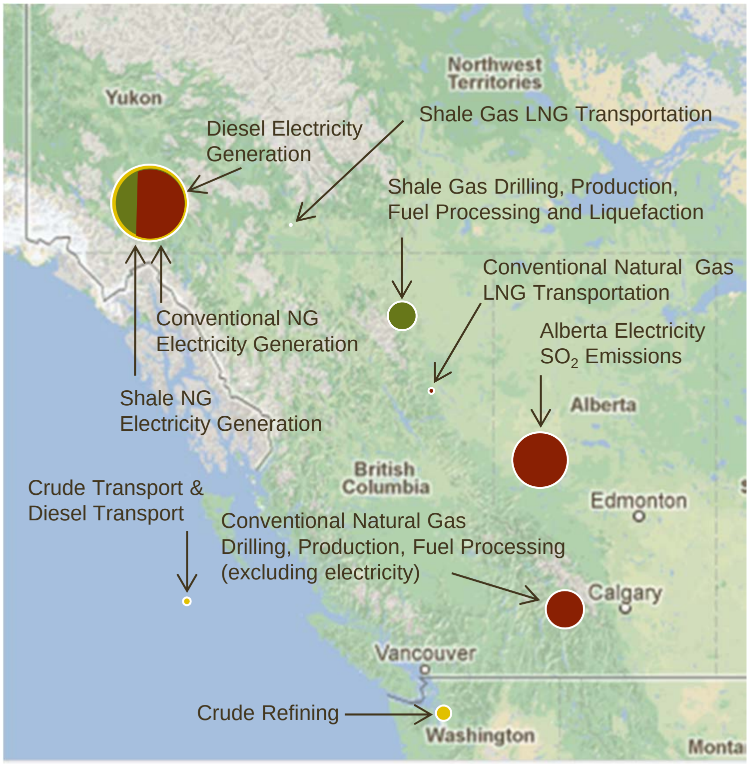


Figure 20: Relative CO Lifecycle Emissions



Particulate Matter (PM) Emissions

Emissions of particulate matter are the result of noncombustible trace constituents in the fuel and lubricating oil of combustion equipment.

Figure 22 shows the relative magnitude of PM emissions at the point of emission. Note that some emissions (transportation and grid sourced electricity emissions) occur across a large geographic area, but are summarized at a single point for illustrative purposes in the figure. Also note that the size of the bubbles *do not* represent the dispersion of emissions, only the magnitude of emissions.

Figure 21: Particulate Matter Emissions (kg PM/MWh)

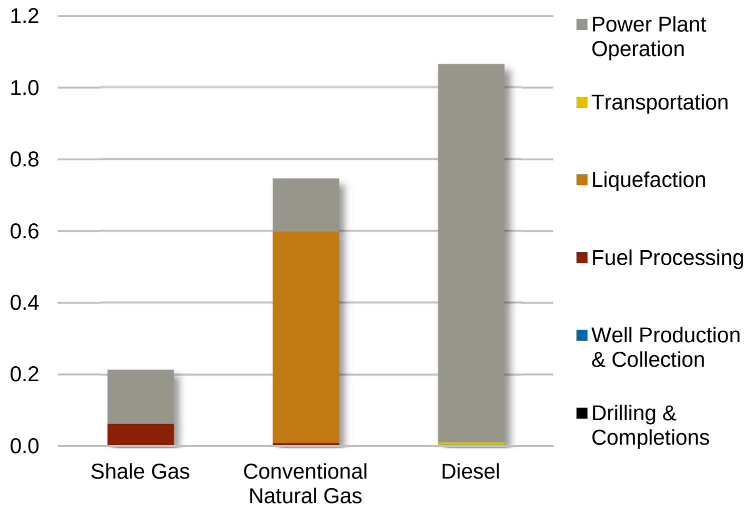
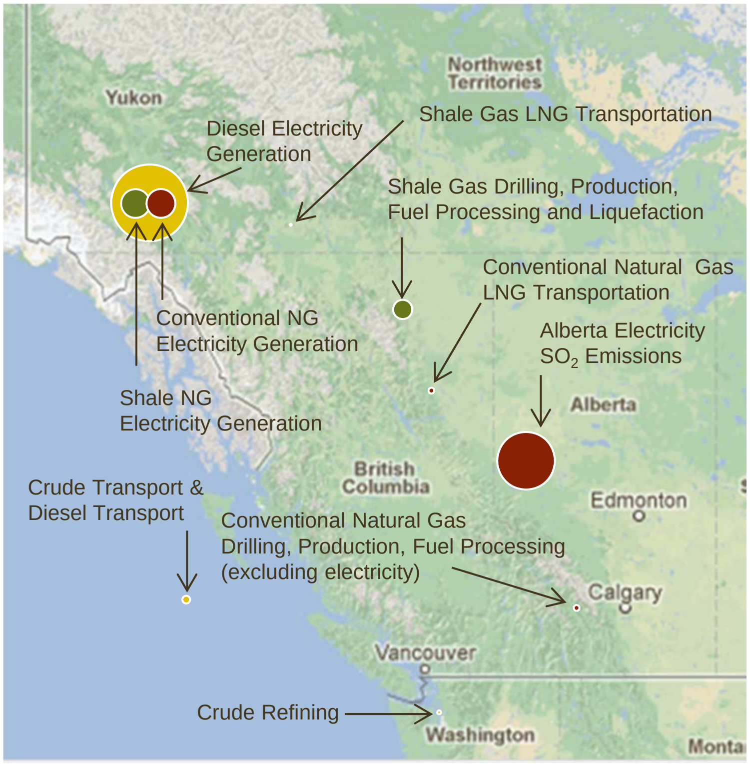


Figure 22: Relative PM Lifecycle Emissions



Sensitivity Analysis

Sensitivity analysis was conducted on four key model variables identified by the study stakeholder group in an effort to better understand the effect of these variables on the lifecycle results. This section provides a description of each sensitivity variable analyzed as well as the results of the analysis.

Sensitivity 1: Flaring versus venting of natural gas drilling and completions emissions

There are several processes in the drilling and well preparation stages as well as the production stage that release raw natural gas, which must be accounted for. The processes involved in drilling, well testing, liquids unloading and well completions are required to prepare a natural gas well for production. Well workovers are conducted during through the production phase on an as-needed basis. There are some differences within these processes between conventional and unconventional natural gas drilling that lead to differences in the volume of raw natural gas that is released from the process.

In most cases, the raw natural gas that is released from these processes is captured and flared, as is required by applicable provincial and federal regulations. Often the volume of gas is too small and the emission period is too short to justify compression and utilization of these volumes.

This sensitivity analysis results presented in the table below show the impact of venting these emissions versus the base case assumption that these volumes are flared. The difference in GHG emissions between the base case (flaring) and the sensitivity analysis (venting) are 16.5 and 28.6 kg CO_2e/MWh over lifecycle of the *Shale Gas* and *Conventional NG* pathways, respectively (an increase of 2.7% and 4.2%, respectively). The sensitivity has no appreciable impact on any other emission category.

The *Diesel* pathway is unaffected by this sensitivity.

Figure 23: Sensitivity 1 – Flaring versus Venting of Natural Gas Drilling and Completions Emissions

		GHG kg CO_2e/MWh	**NOx** kg NO_x/MWh	**SO_2** kg SO_2/MWh	**CO** kg CO/MWh	**PM** kg PM/MWh	**Water** L/MWh
Shale Gas	Flare	594.3	2.1	0.2	1.2	0.2	178.2
	Venting	610.8	2.1	0.2	1.1	0.2	178.2
Conventional Natural Gas	Flaring	679.5	2.3	2.2	1.7	0.7	5.6
	Venting	708.1	2.3	2.1	1.7	0.7	5.6
Diesel	Flaring	694.8	17.8	1.2	1.2	1.1	52.9
	Venting	694.8	17.8	1.2	1.2	1.1	52.9

Sensitivity 2: Water Use in Hydraulic Fracturing

The B.C. Oil & Gas Commission states that water required for hydraulic fracturing in Horn River area is typically, 30,000 – 100,000 m^3 per well. The base case modeled value is 80,000 m^3. Figure 24 below shows water consumption required for hydraulic fracturing as presented in the base case, at 30,000m^3 per well, 100,000 m^3 per well. The range is presented both without and with flowback volumes (where 45% recycling of flowback is assumed and 30% of original injected volume is assumed to flowback).

Figure 24: Sensitivity 2 – Water Use in Hydraulic Fracturing	**Water Consumption** Without Recycling L/MWh	**Water Consumption** With Recycling L/MWh
Base Case 80,000 m^3 per well	176	152
Low Case 30,000 m^3 per well	66	57
High Case 100,000 m^3 per well	220	190

Sensitivity 3: Compressed Natural Gas in Long Distance Trucking

GHG emissions associated with diesel truck transport vary by pathway. From Shale Gas (2.98 kg/MWh to Conventional Gas (16.7 kg/MWh) to Diesel (15.2 kg/MWh). It is important to note that the trucking industry is rapidly adopting natural gas fueled trucks due to significant cost savings in natural gas fuel over diesel. Industry experts estimate that in less than ten years, the majority of new long-haul trucks sold will be natural gas fueled (storing natural gas in either a compressed gas or liquefied state) (New York Times, April 22, 2013).

Several studies of potential lifecycle greenhouse gas emission reductions have shown emission reductions in the range of 7 – 30% depending on natural gas sources, fueling technologies and control technologies applied to manager other pollutants. With increased control requirements for NO_x, CO and PM, there is no significant advantage of natural gas over diesel fueled trucking.

Trucking emissions comprise only a small proportion of total emissions in the total lifecycle of each of the three pathways. Figure 25 below shows the total reduction in emissions that would be achieved if all trucking within each pathway was converted to natural gas at a 20% greenhouse gas emission reduction.

Figure 25: Sensitivity 3 – Compressed Natural Gas in Long Distance Trucking	**Shale Gas Pathway**	**Conv. Natural Gas Pathway**	**Diesel Pathway**
Base Case – Diesel Trucking (kg CO_2e/MWh)	2.98	16.6	15.24
Sensitivity Case – Natural Gas Trucking (kg CO_2e/MWh)	2.1	13.2	13.5
Reduction over full Lifecycle (%)	0.5%	0.1%	0.4%

Sensitivity 4: Global Warming Potentials (GWPs) for Methane (CH_4) and Nitrous Oxide (N_2O)

As discussed above (Exchanges with the Environment – Greenhouse Gasses) for the purposes of this study 100-year GWPs were employed for calculating GHG emissions associated with the defined pathways. It is important to note that the GWP metric has proven challenging to define and employ as a homogeneous metric it relies on both regionally resolved climate change data (temperature, precipitation, winds, etc.) and temporal weighting functions. Thus inherent uncertainties associated with the GWP metric are high and the GWP metric has changed since first developed. For more a detailed discussion on this topic please refer to the IPCC Fourth Assessment Report: Climate Change (2007) sections 2.10 Global Warming Potentials and Other Metrics for Comparing Different Emissions:

(http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10.html)

and TS.2.5 Net Global Radiative Forcing, Global Warming Potentials and Patterns of Forcing: (http://www.ipcc.ch/publications_and_data/ar4/wg1/en/tssts-2-5.html).

Figure 26 details the impact of varying GWPs for Methane (CH_4) and Nitrous Oxide (N_2O) on GHG emissions (reported in terms of CO_2 equivalence) on the 3 LCA pathways.

Figure 26: Sensitivity 4 – Global Warming Potentials (GWPs) for Methane (CH_4) and Nitrous Oxide (N_2O)

	GWP – CH_4	GWP – N_2O	GHG Shale kg CO_2e/MWh	GHG Conv kg CO_2e/MWh	GHG Diesel kg CO_2e/MWh
100 Year GWP (IPCC 4th Annul Report - 2007)	25	298	594.3	679.5	694.8
100 Year GWP (IPCC 2nd Annul Report - 1995)	21	310	577.6	665.7	701.4
20 Year GWP (IPCC 4th Annul Report - 2007)	72	289	792.3	880.4	697.8

In both the natural gas pathways, greater than 97% of methane emissions occur at the final electricity generation stage as a result of incomplete combustion - attributed to the tuning of the air-fuel ratio in the engine to reduce NO_x emissions (lean burn). See Figure 13 for a breakdown of methane emissions by life cycle category within each pathway.

The air-fuel ratio could be adjusted to increase efficiency of combustion, lowering methane emissions but this would lead to increased NO_x emissions (largely because the combustion temperature would be increased).

The reduction in total GHG emissions in the diesel pathway (from the current base case with 100 year GWP to the 20 year GWP) is due to the drop in the N_2O GWP as the methane emissions in that pathway are small on a relative basis.

Scenario Analysis

Two hypothetical scenarios were analyzed to determine the potential impact on the lifecycle exchanges with the environment when compared against the base case scenario.

Scenario 1: Acid Gas Injection

Sequestration of the carbon dioxide found in raw shale gas presents a significant opportunity for reducing emission reductions within the *Shale Gas* pathway. Under the base case scenario, this carbon dioxide is already removed from the raw natural gas during the gas processing process, but it is simply vented to the atmosphere. Sequestration of this carbon dioxide, through a common natural gas industry practice known as acid gas injection, would require incremental electricity consumption to compress and transport the carbon dioxide by pipeline to a storage location.

The precise quantity of carbon dioxide that could be sequestered from the natural gas processing facility depends on the concentration of carbon dioxide in the raw gas being processed. Note that the carbon dioxide involved in this process consists of only carbon dioxide that is removed from the raw natural gas stream; capture of carbon dioxide in any post-combustion gases are not included.

This quantity of carbon dioxide that could be injected has been approximated for the purpose of this scenario to illustrate the potential impact on the lifecycle emissions of the *Shale Gas* pathway as shown in Figure 27 below.

Note that there are negligible changes in air pollutant and water consumption. The base case results for the *Conventional Natural Gas* and *Diesel* pathways are shown for comparison purposes.

Figure 27: Scenario 1 – Carbon Capture and Storage

		GHG kg CO_2e/MWh	NO_x kg NO_x/MWh	SO_2 kg SO_2/MWh	CO kg CO/MWh	PM kg PM/MWh	Water L/MWh
Shale Gas	Base Case	594.3	2.1	0.2	1.2	0.2	178.2
	With CCS	549.8	2.1	0.2	1.1	0.2	178.2
Conventional Natural Gas	Base Case	679.5	2.3	2.2	1.7	0.7	5.6
Diesel	Base Case	694.8	17.8	1.2	1.2	1.1	52.9

Scenario 2: Grid Sourced Electricity versus On-site Natural Gas Generation

Electricity consumption from grid-sourced electricity accounts for a significant proportion of emissions in the *Conventional Natural Gas* pathway. Under this scenario, local natural gas fired electricity generation is used in place of grid-sourced electricity for this pathway. Note that this scenario is provided for illustrative purposes only; there is no know plan to implement local generation at the conventional natural gas processing study location.

The results of the scenario analysis are shown in Figure 28. The base case results for the *Shale Gas* and *Diesel* pathways are shown for comparison purposes.

Figure 28: Scenario 2 – Grid Sourced Electricity versus On-site Natural Gas Generation

		GHG kg CO_2e/MWh	**NO_x** kg NO_x/MWh	**SO_2** kg SO_2/MWh	**CO** kg CO/MWh	**PM** kg PM/MWh	**Water** L/MWh
Shale Gas	Base Case	577.6	2.1	0.2	1.2	0.2	178.2
Conventional Natural Gas	Base Case	665.7	2.3	2.2	1.7	0.7	5.6
	Natural Gas Electricity	604.1	2.2	1.5	1.1	0.2	5.6
Diesel	Base Case	701.4	17.8	1.2	1.2	1.1	52.9

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IPCC Fourth Assessment Report: Climate Change (2007) sections 2.10 Global Warming Potentials and Other Metrics for Comparing Different Emissions (http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10.html) and TS.2.5 Net Global Radiative Forcing, Global Warming Potentials and Patterns of Forcing (http://www.ipcc.ch/publications_and_data/ar4/wg1/en/tssts-2-5.html).

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