WESTERN STATES
AND TRIBAL NATIONS
NATURAL GAS INITIATIVE

Life Cycle Assessment of Greenhouse Gas Emissions from Liquefied Natural Gas Exports from North America's West Coast for Coal-Displaced Electricity Generation in Asia

Authors
Adebola S. Kasumu, PhD, P.Eng.†*
Kerry Kelly. PhD‡
Lauren P. Birgenheier, PhD‡

†A.S.K. Consulting Ltd.
‡University of Utah, Salt Lake City, Utah 84112, USA
*Corresponding Contact: askasumu@ucalgary.ca, +1 (403) 966 3715

Acknowledgments

Western States and Tribal Nations would like to thank the following allies and stakeholders for sponsoring this important study. We would also like to give special thanks to Wes Adams, Deputy Assistant Director, Oil & Gas, Utah School and Institutional Trust Lands Administration (SITLA) for his insights, management and counsel throughout the preparation of the study.

Sponsors:

- Ute Indian Tribe
- United Brotherhood of Carpenters
- LiUNA/Colorado Laborers
- Duchesne County, UT
- Uintah County, UT
- Utah School and Institutional Trust Land Administration
- Utah Governor's Office of Energy Development
- Four Corners Innovation
- Four Corners Economic Development
- Wyoming Energy Authority

About Western States and Tribal Nations Natural Gas Initiative

Western States and Tribal Nations (WSTN) is a unique, trans-national initiative led by state, county and sovereign tribal nation governments focused on creating rural economic development, advancing tribal self-determination and reducing global emissions by exporting western North American natural gas to international markets that need lower-emitting fuels.

Table of Contents

Life Cycle Assessment of Greenhouse Gas Emissions from Liquefied Natural Gas Exports from North America's West Coast for Coal-Displaced Electricity Generation in Asia

List of Exhibits

List of Exhibits

Acronyms and Abbreviations

API	American Petroleum Institute
AR5	Fifth Assessment Report
bbl	Barrel
Bcf	Billion cubic feet
Bcf/yr	Billion cubic feet per year
BCFG	Billion cubic feet of gas
BH	Bighorn
BHB	Bighorn Basin
CBM	Coalbed methane
CDPHE	Colorado Department of Public Health & Environment
CH_4	Methane
CI	Confidence Interval
CO_2	Carbon dioxide
CO_2 -e	Carbon dioxide equivalents
DJ	Denver-Julesburg
DOE	Department of Energy
EF	Emission factor
EGDB	Energy Resources Program Geochemistry Laboratory Database
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ft	Feet
g	Gram
GDB	Great Divide Basin
GGR	Greater Green River
GRB	Green River Basin
GHG	Greenhouse gas
GHGI	Inventory of U.S. Greenhouse Gas and Sinks
GHGRP	Greenhouse Gas Reporting Program
GWP	Global warming potential
H_2S	Hydrogen sulfide
HF	Hydraulically fractured
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
km	Kilometer
kWh	Kilowatt hour
LCA	Life cycle assessment
Mcf	Thousand cubic feet
MJ	Mega joule
MMbbl/yr	Million barrels per year
MTPA	Million tonnes per annum
N_2O	Nitrous oxide
NETL	National Energy Technology Laboratory
NG	Natural gas
NGL	Natural gas liquid
O&G	Oil and Gas
PX	Paradox
PB	Piceance Basin
PIC	Piceance
PR	Powder River
RT	Raton
RB	Raton Basin
SE	Standard Error
SJ	San Juan
SJB	San Juan Basin
SSC	Source Classification Code
SUIT	Southern Ute Indian Tribe Shale Development
T&D	Transmission and distribution
tonne	Metric ton
TRFO	Tres Rios Field Office
TWh	Terawatt hour
UB	Uinta Basin
UIN	Uinta
UGS	Utah Geological Survey
U.S.	United States
USGS	United States Geological Survey
WR	Wind River
WRB	Wind River Basin
yr	Year

Abstract

This study aims to determine the net impact of global greenhouse gas emissions from liquefied natural gas (LNG) sourced in the following western United States basins; Greater Green River, Uinta, Piceance, San Juan, Powder River, Bighorn, Wind River, Paradox, Denver-Julesburg and Raton ("Collectively" Rockies Gas) which could be exported to Asian countries from Pacific Coast terminals located in Baja California, Mexico and Coos Bay, Oregon to replace coal-fired power generation in importing countries. Based on proved reserves, historical production rates, and current gas development and production technologies, the basins of interest are predicted to meet domestic gas needs and estimated Pacific coast LNG terminal contracts for ~12 years. The predicted gas supply may be adjusted upwards and lengthened with future gas resource and proved reserve assessment studies, as well as technologies that focus on improved recovery factors. Using methodologies from a 2018 predecessor study titled; [1] Country-Level Life Cycle Assessment of Greenhouse Gas Emissions from Liquefied Natural Gas Trade for Electricity Generation (Original Study), life cycle assessments (LCA) greenhouse gas (GHG) emissions of electricity generation using Rockies Gas in importing countries were compared to life cycle GHG emissions of local coal-fired electricity generation in importing countries. This study focused on replicating the Original Study under the following criteria: (1) a review of viable electricity generation markets for LNG in Asia, (2) using published data sources, develop results for life cycle greenhouse gas emissions that account for upstream natural gas production, midstream processing/liquefaction & pipeline transportation, shipping to importing nations including the necessary infrastructure required for power generation and delivery, and (3) emissions displacement of coal-fired electricity. Renewable power generation effects on the emissions displacement are not assessed within this study and do not represent a significant portion of the overall energy mix for importing countries, because natural gas imports have largely been responsible for most coal-fired power generation disruption taking place. We highlight national regulations, environmental policies that could play a role in mitigating emissions with global transitional power generation strategies in mind.

[1] Kasumu, Adebola S, Vivian Li, James W Coleman, Jeanne Liendo, and Sarah M Jordaan. 2018. "Country-Level Life Cycle Assessment of Greenhouse Gas Emissions from Liquefied Natural Gas Trade for Electricity Generation." *Environ. Sci. Technol* 52 (4): 1735-1746. doi:https://doi.org/10.1021/acs.est.7b05298.

Introduction

The impact of human activity on the climate system has never been more profound than it has been in recent decades, with recent anthropogenic emissions of greenhouse gases (GHGs) rising to the highest levels in human history, leading to widespread impacts on human and natural systems (IPCC AR5). As the awareness of climate change, its impacts, and the causes continue to increase, so has the collective willingness to take mitigating actions against this existential threat, with support from individuals, organizations (both private and public), and governments around the globe. Without an overarching global authority with true regulatory power over sovereign actors, success in creating a future that protects our planet's environment and our world economy must involve every nation voluntarily. This willingness to become engaged and take action has manifested itself in many ways including the increasing generation of power from less carbon-intensive and renewable sources, the increasing adoption of electric vehicles, and the continuous improvement of technologies associated with energy resource extraction and power generation. Recently, the U.S. Government took executive action on "protecting public health and environment and restoring science to tackle climate crisis" (U.S. Presidential Executive Order 13990, 2021).

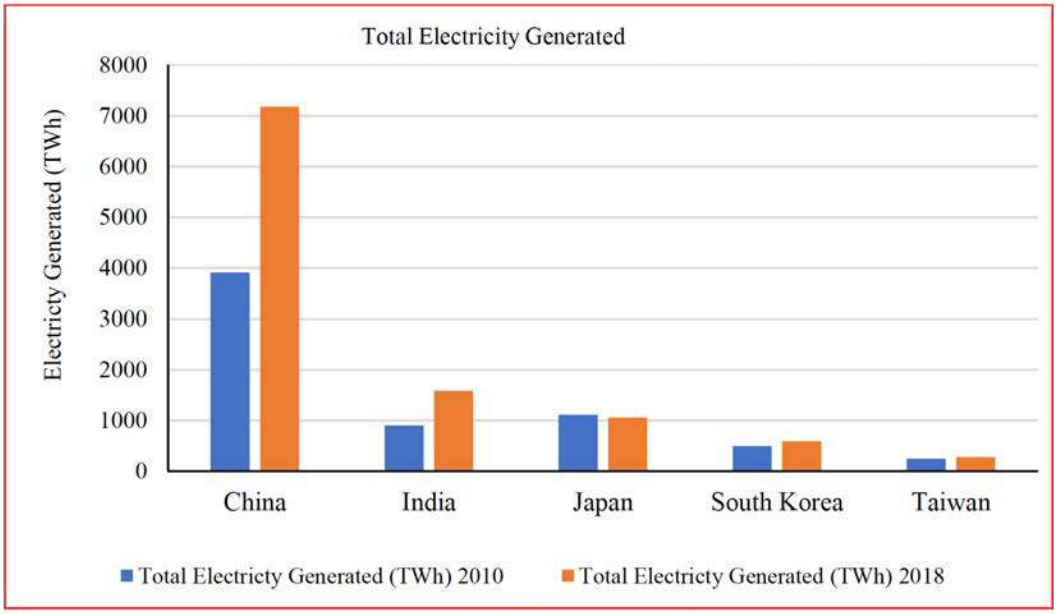
Technological advances in natural gas (NG) extraction created a recent boom in North American natural gas production. This boom has elevated the discussion on the role of natural gas, a cleaner-burning fuel, as a bridge to achieving the global goals on sustainability and mitigating the effects of climate change, and at the same time, helping to meet the ever-increasing global energy demand. In addition, this boom has become an impetus for the natural gas industry to find alternative markets across the globe (Kasumu et *al*., 2018).

One of the primary uses of natural gas is in electricity generation, where GHG reductions may be realized, depending on the electricity generation source that is displaced by it. According to the U.S. Energy Information Administration (U.S. EIA: FAQ), the replacement of coal-fired power with natural gas-fired electricity in the U.S. results in reductions of many pollutants (e.g., mercury) and up to 60% of GHG intensity for power generation (intensity is defined as the quantity of CO 2 equivalent emitted per unit electricity generated). However, it is noted that net GHG reduction benefits are expected to be reduced by supply chain factors when natural gas is exported for electricity generation, due to the additional life cycle stages of liquefaction, ocean transport, and regasification in the importing country.

The focus of this study is to assess the implications of exporting U.S. natural gas, utilizing Coos Bay, Oregon and Costa Azul, Baja California as liquefied natural gas (LNG) export terminals, from the Rocky Mountain Basins to China and other Asian countries for electricity generation in order to displace portions of their coal-fired electricity. Studies have already been performed by the U.S. Department of Energy (DOE)/National Energy Technology Laboratory (NETL) and other researchers (Roman-White *et al*., 2019; Kasumu *et al*., 2018; Pace Global, 2015) on the GHG implications of exporting U.S. natural gas to Asian countries for electricity generation, however, the specific natural gas source and export terminals used in this study make it somewhat different. [2] Costa Azul Phase One is the conversion of an established plant designed for LNG imports, which will be reversed engineered to liquefy natural gas for exports. Although the Jordan Cove project is still in the design and permitting stages, Pembina Pipeline has indicated it will pause development of the Jordan Cove LNG export plant in Coos Bay, OR. In an April 22nd , 2021, filing to the U.S. Court of Appeals for the District of Columbia, Pembina said it was “assessing the impact of recent regulatory decisions involving denial of permits or authorizations necessary for the project to move forward” (Reuters, 2021).

The choice of China and other Asian countries as potential import countries of USWC LNG is not surprising because China was by far the top electricity-consuming country in the world in 2018, while India and Japan were among the top five, with South Korea being the 6 th largest electricity-consuming country (IEA, 2020). Electricity generation data sourced from different sources (EIA, 2013; IEA, 2012; IEA, 2020; ESH, 2012; ESH, 2018) for these five countries are presented in Exhibits 1-1 to 1-5.

Exhibit 1-1: Total Electricity Generated in Potential Import Countries



[2] Two LNG plants are proposed to be built close to the proposed export terminals; a 15 MTPA capacity plant at Costa Azul and a 7.8 MTPA capacity plant at Jordan Cove, Collectively U.S. West Coast Plants (USWC LNG) in this report.

Exhibit 1-2: Coal Electricity Generated in Potential Import Countries

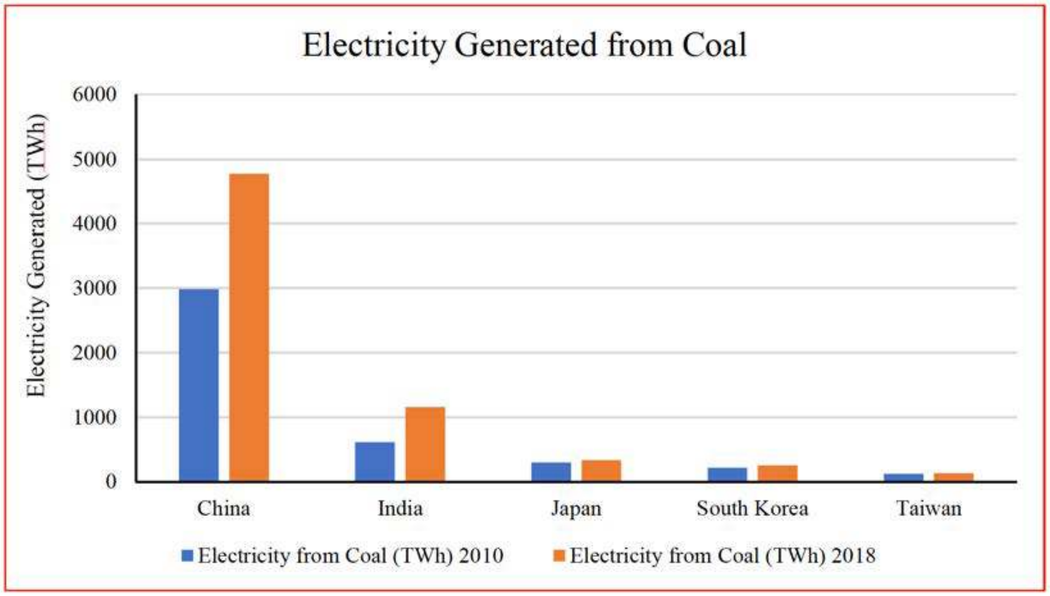


Exhibit 1-3: Share of Coal Electricity Generated in Potential Import Countries

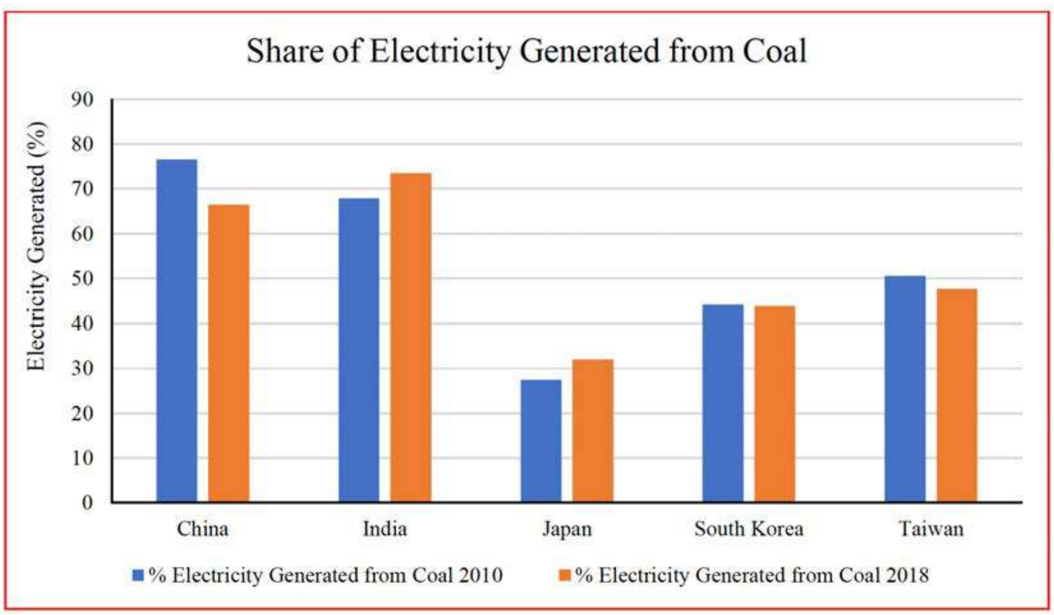


Exhibit 1-4: Natural Gas Electricity Generated in Potential Import Countries

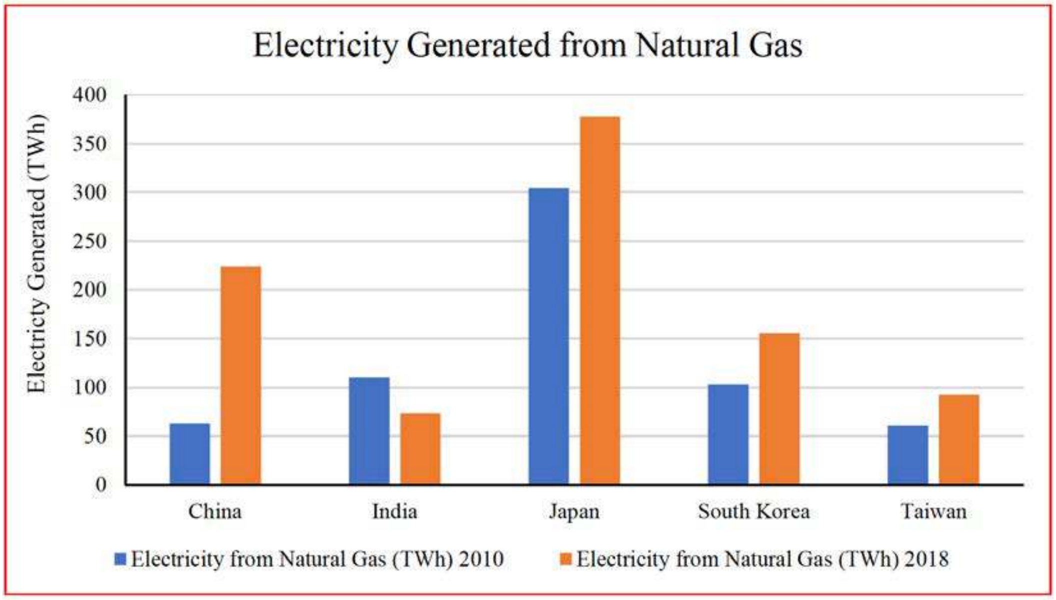


Exhibit 1-5: Share of Natural Gas Electricity Generated in Potential Import Countries

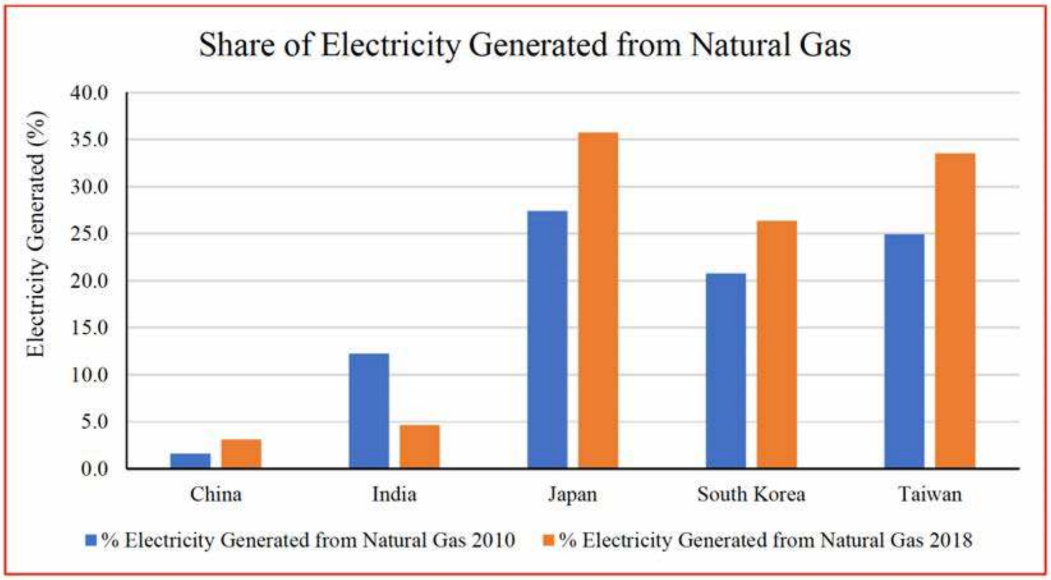


Exhibit 1-1 shows that the total electricity generated in China and India has increased by 84% and 75%, respectively, between 2010 and 2018. While there have been much smaller increases in South Korea and Taiwan, Japan has dropped by 5% in the same time period. Exhibits 1-2 and 1-3 show that while coal-fired electricity in China has increased by 60% from 2010 to 2018, the share of coal-fired electricity within the overall generation mix has decreased from 77% to 66%. Conversely, Exhibits 1-4 and 1-5 show an increase of 255% in natural gas-generated electricity, and an increase in the share of natural gas-generated electricity within the overall generation mix, from 1.6% in 2010 to 3.1% in 2018. The increase in the both the quantity of gas-fired electricity and the share of the generation mix shows that there is an ample opportunity for natural gas-fired electricity to continue to grow in China, and that the trend will most likely continue for the foreseeable future, given China's commitment to peaking CO_2 emissions before 2030 and achieving carbon neutrality by 2060 (Climate Action Tracker). The same trend, albeit to a lesser extent, can be observed for Japan, South Korea and Taiwan. However, in India, not only has the coal-fired electricity and its share of the generation mix increased from 2010 to 2018, but natural gas-fired electricity and its share of the generation mix have both reduced in the same time period.

LNG Markets

In 2019, the global LNG market grew at an all-time rate of 13.0%, setting a record increase in annual LNG imports, reaching 354.7 million tons. While LNG demand declined in Japan and South Korea in 2019, Asian LNG demand, which accounted for 69% of the global LNG demand, continued to be boosted by China, with an increase of 14% in LNG imports, compared to the prior year (GIIGNL, 2020). Overall, it is expected that global LNG demand will reach 700 MTPA, nearly double current levels, with Asia expected to drive nearly 75% of this growth as domestic gas production reduces and LNG replaces higher emission energy sources (Oil & Gas Journal, 2021).

Japan, South Korea, and Taiwan are described as traditional LNG buyers, being developed economies with strong financial capacities and a long history of importing LNG (Moore *et al*., 2014). Natural gas use for electricity in Japan grew by 25% between 2010 and 2018, with the demand satisfied mainly by LNG imports and is currently the world's largest LNG importer, accounting for 22% of total LNG imports in 2019 (GIIGNL, 2020). South Korea is the third largest LNG importer worldwide with a 51% growth in natural gas use for electricity between 2010 and 2018. South Korea's LNG imports was 11.3% of total global LNG imports in 2019 (GIIGNL, 2020). Changes in Korea's energy policy imply an increasing use of LNG for power generation and less reliance on nuclear power (Kasumu *et al*., 2018). Natural gas demand in South Korea is expected to increase by almost 2% per year through 2035 (Moore *et al*., 2014). Taiwan is another potential market for USWC LNG, with natural gas use for electricity increasing by 52% between 2010 and 2018. Taiwan accounted for 4.7% of world's LNG imports in 2019 (GIIGNL, 2020), while at the same time coal is the largest source of electricity generation at 48% in Taiwan, followed by natural gas at 34%.

While identified as attractive markets for LNG, China and India are described as nontraditional buyers of LNG, meaning that they are less developed economies with a relatively short history of buying LNG, starting in the early to mid-2000s (Moore *et al*., 2014). China's relative strong economic growth with an increasing demand for energy is a result of its growing population and the increasing proportion of its population entering the middle class (Kasumu *et al*. 2018). Energy markets in India are also expected to grow, where LNG imports constituted 6.8% of world's total LNG imports in 2019, and also grew by 7% relative to 2018 (GIIGNL, 2020).

Two new regasification or LNG import terminals started commercial operations in China in 2019. One with a capacity of 0.6 MTPA while the other has a capacity 0.8 MTPA. Ongoing expansion programs in existing terminals are expected to add more than 15 MTPA of regasification capacity by 2021. A 5.0 MTPA regasification terminal was commissioned on the east coast of India in 2019, while another 5.0 MTPA (expandable to 10 MTPA) was commissioned in the state of Gujurat in February 2020. Other ongoing projects at various stages of completion are expected to add additional regasification capacity of at least 16.0 MTPA between 2020 and 2022, with room for expansion. In Japan, Hokkaido Gas is currently expanding the Ishikari LNG Terminal in Hokkaido, while Japan's energy for a new era (JERA) has completed the construction of two storage tanks with a capacity of 125,000 m 3 each at its

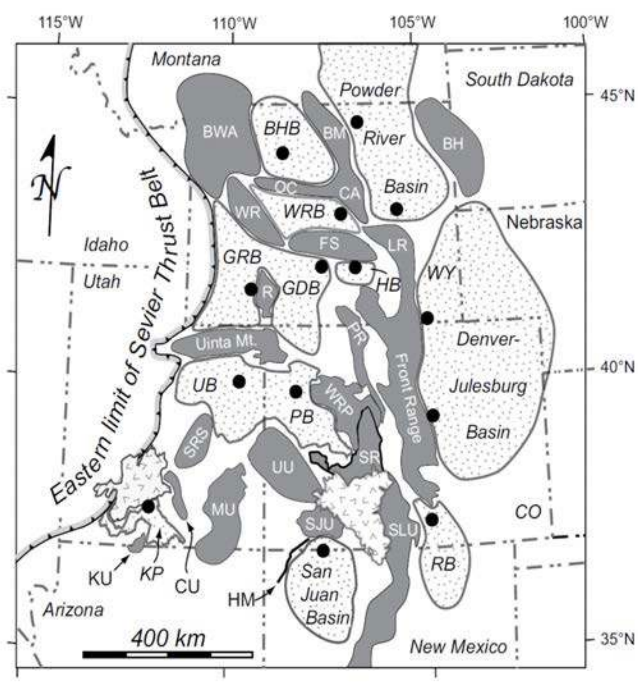
Futtsu terminal and has added four Boil-off Gas (BOG) compressors at the Chita terminal. Various expansion projects are also ongoing in South and Taiwan (GIIGNL, 2020).

In 2019, 26 long &medium-term contracts (greater than 4 years) were concluded while 5 short-term contracts were concluded. The average duration of long & medium-term contracts in 2019 was 13.9 years [emphasis added]. In total, there were about 311 long & medium-term contracts in force in 2019 (GIIGNL, 2020).

3. Gas Resource Estimates and Production History for Rocky Mountain Basins

Published gas resource estimates, proved reserves, and production history data were used to predict LNG production scenarios for the Rocky Mountain region. Undiscovered gas resource estimates were compiled from United States Geological Survey (USGS) studies carried out over the last 14 years (USGS Uinta-Piceance Assessment Team, 2002; USGS, 2005; USGS Southwest Wyoming Province Assessment Team, 2005; Higley *et al.*, 2007a; Higley *et al.*, 2007b; Anna, 2010; Kirschbaum *et al.*, 2010; Whidden *et al.*, 2012; USGS San Juan Basin Assessment Team, 2013; Hawkins *et al.*, 2016; Finn *et al.*, 2018; Drake *et al.*, 2019; Finn *et al.*, 2019; Schenk *et al.*, 2019). For the purpose of this study, 10 basins were identified as areas of interest across the four states of Wyoming, Utah, Colorado and New Mexico and include the Powder River, Bighorn, Wind River, Greater Green River, Uinta, Piceance, Denver-Julesburg, Paradox, San Juan, and Raton Basins (Exhibit 3-1).

Exhibit 3-1: Map of Rocky Mountain Uplifts and Basins (Heller and Liu, 2016). Basins of interest include Powder River Basin, Bighorn Basin (BHB), Wind River Basin (WRB), Greater Green River Basin, which includes Green River Basin (GRB) and Great Divide Basin (GDB), Uinta Basin (UB), Piceance Basin (PB), Denver-Julesburg Basin, San Juan Basin (SJB), and Raton Basin (RB). Paradox Basin in the four corners region not pictured.

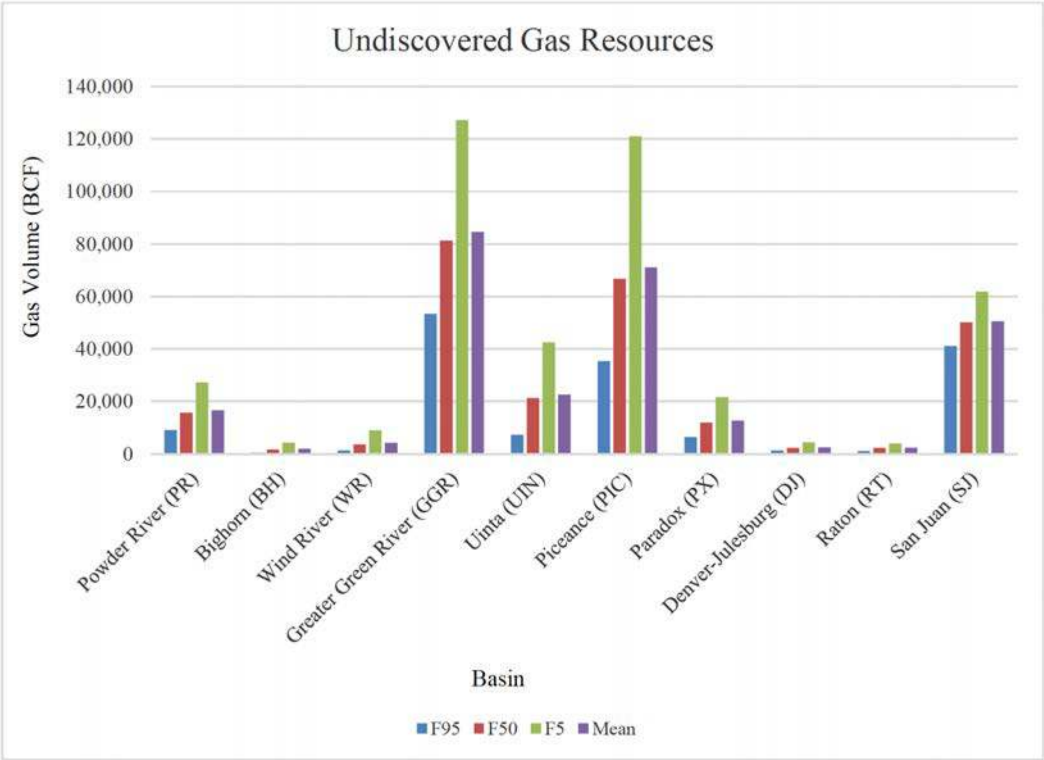


3.1. Undiscovered Gas Estimates

The Greater Green River Basin hosts the largest accumulation of undiscovered gas, followed by the Piceance Basin, San Juan Basin and Uinta Basin, respectively (Exhibit 3-2 and Exhibit A-1). The Paradox Basin and Powder River Basin contain some undiscovered gas, which could provide additional upside to the four major stand-alone basins (Exhibit 3-2 and Exhibit A-1). According to USGS estimates, the undiscovered accumulations of gas in the Bighorn, Wind River, Denver-Julesburg, and Raton Basin are quite small (Exhibit 3-2 and Exhibit A-1). Notably, two of the most recent studies, which are also focused studies on particularly gas-rich formations like the Mancos Shale and the Mesaverde and Wasatch (Hawkins, 2016; Drake, 2019), report some of the most significant undiscovered gas resource estimates. If additional up- to-date resource evaluation studies focused on gas-rich targets in other Rocky Mountain Basins were also carried out, those studies would likely result in higher undiscovered gas estimates in many other Rocky Mountain Basins of interest.

Detailed results of undiscovered gas estimates showing all the basins for conventional and unconventional gas sources are presented in Appendix A.

Exhibit 3-2: Undiscovered gas estimates in billion cubic feet of gas (BCFG) as reported from USGS studies cited in Exhibit A-1 by basin in Appendix A.



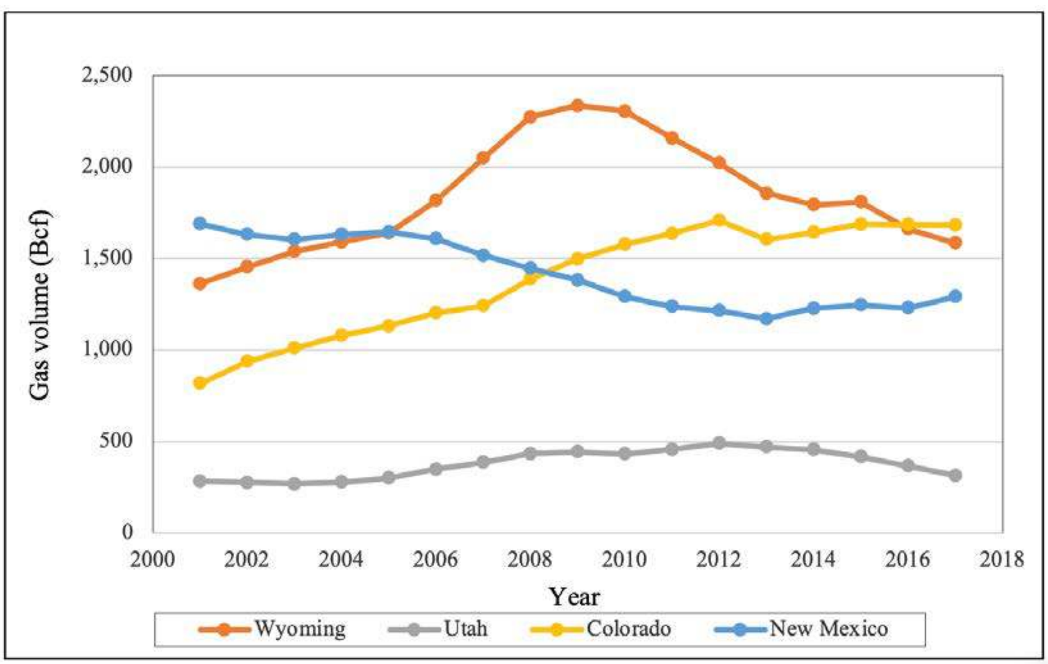
3.2. Proved Gas Reserves and Production

Proved gas reserves and annual gas production data by state, including Wyoming, Utah, Colorado and New Mexico, were compiled from the Utah Geological Survey's (UGS) online data repository, Utah Energy and Mineral Statistics (https://geology.utah.gov/resources/energy/utah-energy-and-mineral-statistics/), Tables 4.1 and 4.3, respectively. Data through 2017 were utilized for this study, as that was the data available at the time of data compilation for this study. Proven gas reserves (2017 estimates) are shown in Exhibit 3-3. Annual gas production by state, from 2001-2017, are shown in Exhibit 3-4.

Exhibit 3-3: Proved gas reserves (2017) in BCFG as reported in UGS Utah Energy and Mineral Statistics Table 4.1 online data repository at https://geology.utah.gov/resources/energy/utah-energy-and-mineral-statistics.

State	Non-Associated Natural Gas	Associated-Dissolved Natural Gas	Total Wet After Lease Separation	Shale Gas	Coalbed Methane	Total Dry
Colorado	17,224	11,503	28,727	1,885	3,275	26,573
Wyoming	21,312	1,040	22,352	28	1,014	21,549
New Mexico	11,266	9,592	20,858	9,451	3,175	19,365
Utah	3,224	665	3,889	*	438	3,752
	53,026	**22,800**	**75,826**	**11,364**	**7,902**	**71,239**

Exhibit 3-4: Historical Marketed Gas Production by State, 2001 - 2017

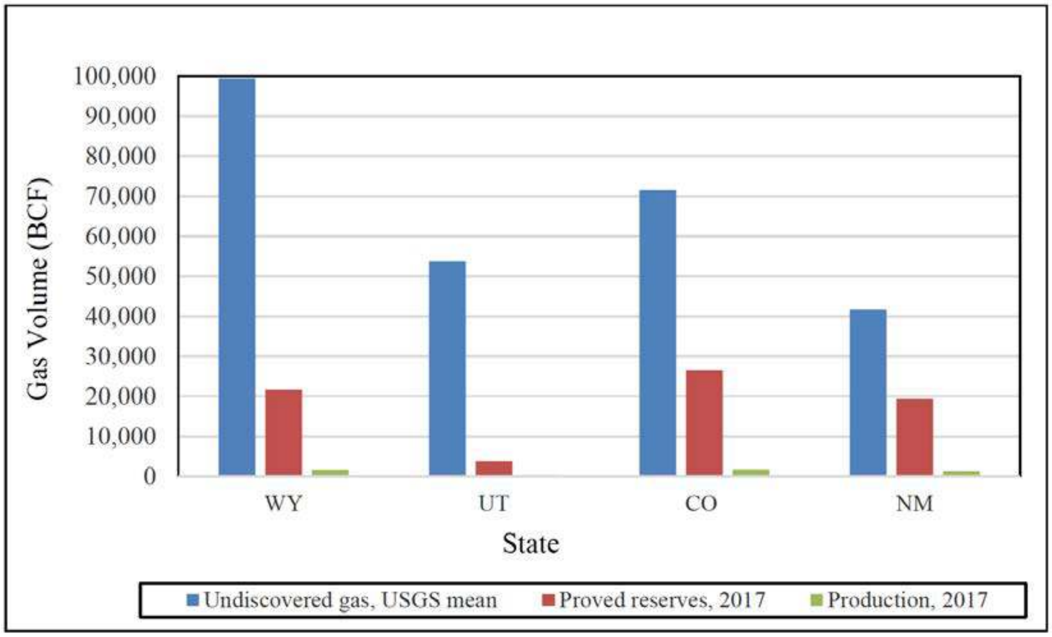


Undiscovered gas resource estimates for this study are reported by basin, whereas proved gas reserves and gas production data are reported by state. In order to compare and contrast estimates of undiscovered gas resource, proved gas reserves, and gas production volumes, a basin-to-state conversion was developed as a back-of-envelope calculation, based on known areal extent of each basin (Exhibit 3-5). This exercise enabled a comparison between the annual gas production (for 2017), the proved reserves, and the undiscovered resources for the four states of Wyoming, Utah, Colorado and New Mexico, which include the basins of interest. This comparison is presented in Exhibit 3-6.

Exhibit 3-5: Basinal area converted to state area, which was used to convert basin-based undiscovered gas resource estimates to state-based undiscovered gas resource estimates reported in Exhibit 3-6.

Basin	State 1	Area of Basin in State 1 (%)	State 2	Area of Basin in State 2 (%)
Powder River (PR)	WY	100	-	-
Bighorn (BH)	WY	100	-	-
Wind River (WR)	WY	100	-	-
Greater Green River (GGR)	WY	90	CO	10
Uinta (UIN)	UT	95	CO	5
Piceance (PIC)	CO	100	-	-
Paradox (PX)	UT	67	CO	33
Denver-Julesburg (DJ)	CO	80	WY	20
Raton (RT)	CO	50	NM	50
San Juan (SJ)	NM	80	CO	20

Exhibit 3-6: Comparison of Undiscovered Gas Resources, Proved Reserves and 2017 Production by State.



3.3. Predicted Produced Gas for LNG Plants Based on Proved Reserves

Based on the all the unit conversions and properties of the natural gas used in this study, it is estimated that, assuming the four Rocky Mountain states of Wyoming, Utah, Colorado and New Mexico continue to produce and market at the 2017 gas volume levels, there is enough gas for production ramp-up to supply the proposed USWC LNG plants for about 12 years, based on the 2017 proved gas reserves figures. The 12-year estimated gas supply for USWC LNG plants assumes annual domestic gas needs will remain steady at the 2017 volumes, and that the remainder of proved reserves can be exported annually to meet the proposed 22.8 MTPA (1 MTPA of LNG ~ 50 BCFG/yr) needed to supply USWC LNG plants.

There are a few assumptions in the above estimate that the basins of interest could supply USWC LNG plants with about 12 years of needed gas, and some assumptions are more certain than others. Here, we comment on the assumptions and their relative certainty. First, the calculation assumes all present proved reserves are drilled and developed. The "proved reserves" are defined as the amount of hydrocarbon resources that can be recovered from a deposit with a reasonable level of certainty, so using proved reserves estimated gas volume carries a significant amount of certainty. However, proved reserves estimates generally do not consider predicted future changes in existing land use or environmental policies, which could prove to be significant.

Second, the 12-year calculation assumes proven reserves volumes will not change in the future. However, in general, with additional study and resource assessments, it is likely both undiscovered resource and proved reserve gas estimates will increase, based on industry correlations. This upward adjustment trend is a common one as the geologic and engineering understanding of a resource is revised through time. The understanding of unconventional gas resources has expanded greatly over the last decade, yet many of the gas resource assessments used in this study were performed over a decade ago. As such, it is important to LNG development efforts to prioritize and fund new gas resource assessments that utilize a modern understanding of unconventionals.

Finally, the 12-year calculation assumes 2017 domestic gas production rates will continue into the future. This assumption may not be realistic, but stands as the best way to move forward with a back-of-the envelope calculation. Based on historical records, domestic gas production rates will change annually (see Exhibit 3-4). Predicting how they might change in each state is subject to a variety of economic and geopolitical factors beyond the scope of this study. Furthermore, predicting future gas prices, which are a strong driver of domestic production rates, is challenging but additional production could be incentivized because of the lower emission component of natural gas as a source of energy when compared to coal.

Improved technologies for drilling and production of gas that enhance primary recovery factors may also positively impact proven reserves and gas production rates. Furthermore, future engineering and technology advancements in drilling and development may work favorably to improve the economic climate and model for gas extraction in the future.

4. Estimation of GHG Emissions from Life Cycle Stages of USWC LNG Supply Chain

This study utilized published data and results from several independent studies (cited in the different subsections) for the estimation of emission factors for the various life cycle stages of the proposed USWC LNG supply chain. Such studies have also published key parameter inputs and assumptions used in their modeling to generate data that have been used as estimates or used to derive estimates in this study.

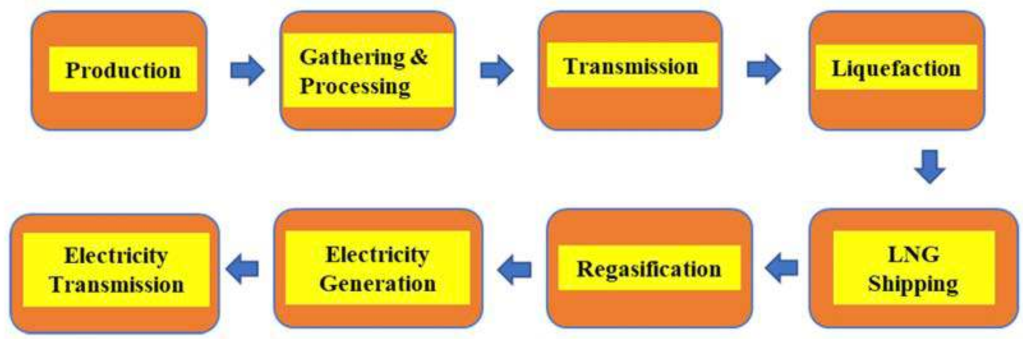
All GHG calculations in this study were based on the 100-year time horizon Intergovernmental Panel on Climate Change Fifth Assessment Report (AR5) (IPCC, 2013) global warming potential (GWP100) values for methane (CH4) and nitrous oxide (N2O), relative to Carbon dioxide (CO2). These values are presented in Exhibit 4-1 below.

GHG	GWP	Unit
CO_2	1	g CO2-e/g CO_2
CH_4	36	g CO2-e/g CO_2
N_2O	298	g CO2-e/g CO_2

Based on a U.S. average heating value of 1,037 Btu/ft^3 (EIA website) and a natural gas density of 22 g/ft^3 (DOE/ORNL, 2011), the 22.8 MTPA of liquefaction capacity of the proposed USWC LNG plants were estimated to be able to generate 156.73 TWh/yr of electricity, based on the average power plant efficiency of U.S. fleet baseload of 46.4% (Roman-White *et al*., 2019).

The various life cycle stages analyzed in this study include, natural gas production (extraction), gathering and processing, gas pipeline transmission, liquefaction, LNG shipping, LNG regasification, electricity generation, and electricity transmission and distribution (T&D). This sequence is shown in Exhibit 4-1. After extraction and processing, natural gas is transported by pipeline to a liquefaction facility where it is liquified and loaded onto an ocean tanker, it is transported to an LNG terminal with regasification operations, regasified, and then fed to a pipeline that transports it to a power plant. The construction and operation of LNG infrastructure is accounted for in the data for the LNG supply chain (Roman-White *et al*., 2019). One significant assumption made by Roman-White *et al*. (2019) is that the power plant in the import country is close to the regasification facility, thus no additional gas pipeline transport was accounted for after regasification. The same assumption has been adopted in this study.

Exhibit 4-1: LNG Life Cycle Assessment Stages.



4.1. Greenhouse Gas Emission Factors from Gas Production, Gathering/Boosting and Processing

Region-specific upstream (extraction and processing) GHG emission factors and associated uncertainties for the Rocky Mountain Region (WY, NM, CO and UT) were identified and collected (Littlefield *et al.*, 2019; Westar, 2014; Ramboll Environ, 2018a; Ramboll Environ, 2018b; EIA, 2018; DrillingInfo, 2018; Vaughn *et al.*, 2017). Emission factors were gathered from published resources as well as gray literature (i.e., state and industry-group sponsored research).

The GHG emissions associated with oil and gas production occur during site preparation, drilling/completion, production, processing and transport stages. The extent of the emissions can vary widely depending on formation properties, the type of process, operating procedures as well as the nature and the condition of equipment used. Emission estimates can also vary depending on the methods employed (i.e., individual devices and facilities (bottom-up studies) or atmospheric measurements (top-down studies), as well as the underlying assumptions. Overall, well completion activities (including hydraulic fracturing) tend to dominate potential emissions associated with oil and gas production.

4.1.1. Information Sources

Following a review of recent publications on GHG emissions associated with upstream natural gas emissions, the estimates used in this section are based on the report of DOE/NETL on life cycle analysis of natural gas extraction and power generation (Littlefield *et al.*, 2019), WESTAR 2014 Oil and Gas emissions Inventory for Greater San Juan Basin in Colorado and New Mexico Area report (WESTAR, 2014), and the Future Year 2028 Emissions from Oil and Gas Activity in the Greater San Juan Basin and Permian Basin report (Ramboll Environ, 2018a). Emission factors for the following Rocky Mountain Basins were included: Uinta (conventional and unconventional), Green River (conventional and unconventional), Piceance (unconventional), and San Juan (conventional and unconventional). Other smaller basins that exist in the study area have production that is substantially lower than the basins for which emission factors were developed, and basin-specific emission estimates for these basins could not be identified. Thus, averages of emission factors from the larger basins were used for these smaller basins, albeit insignificant in weighted values.

4.1.2. Methods

Most of the recently published studies for the basins of interest focus on evaluations of methane leakage from gas production, processing, transportation and distribution of conventional and unconventional natural gas. The term conventional natural gas is used for production from wells using vertical extraction in high-permeability formations and that do not require stimulation technologies for primary production. The term unconventional natural gas is used for production using hydraulic fracturing and extracted from low-permeability formations, which is used widely in shale gas and tight gas production. The Coalbed methane (CMB) extraction technology refers to natural gas extracted from coal seams that requires the removal of naturally occurring water from the seam before natural gas wells are productive.

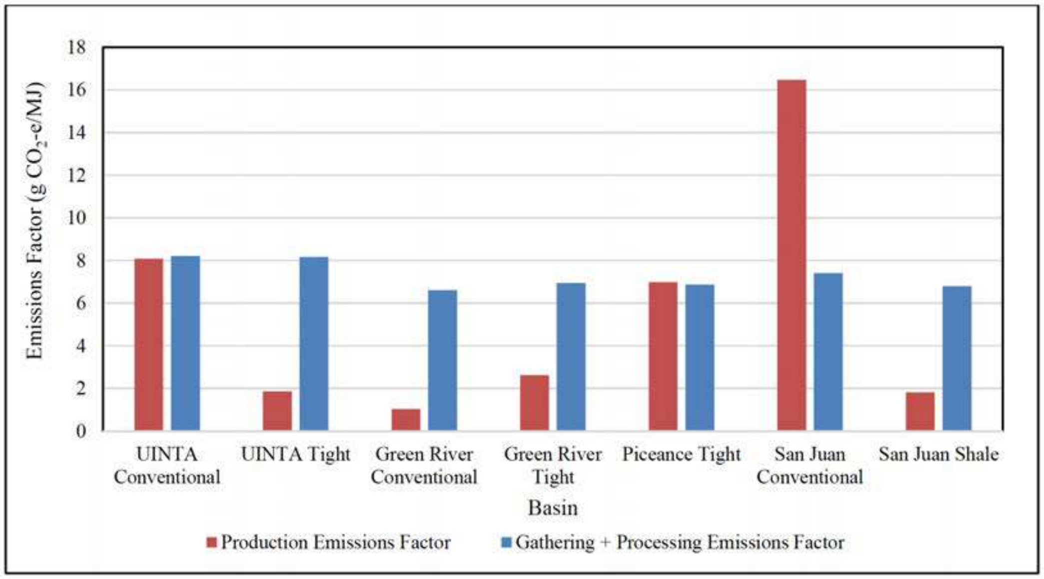
Most of the recently published studies are based on top-down techniques and do not report individual emission factors for different activities involved in the production and processing stages, which is an important objective of this study. Therefore, only bottom-up measurements or models associated with gas production have been considered in this study. The compiled information included the emissions from pre-production (site preparation, drilling, hydraulic fracturing, well completion and workovers); production (leakage and venting from well equipment and liquid unloading); and gathering, boosting and processing (including acid gas removal, dehydration, compression operations, pneumatic devices and pumps). The NETL model (Littlefield *et al.*, 2019) did not provide an estimate of emissions associated with shale gas production, so the Future Year 2028 Emissions from Oil and Gas Activity in the Greater San Juan Basin and Permian Basin report (Ramboll Environ, 2018a) was used to estimate these emission factors because the Future Year 2028 predictions delineated between oil and gas emissions, and was used as a logical method for backing into a 2018 estimate.

4.1.3. Results

A summary of the total of the emissions for production, gathering/boosting, and processing stages and their corresponding uncertainties are presented in Appendix B. The emissions are reported in terms of 100-yr GWP. Detailed emission factors including the different activities involved in the production and processing stages, the methodology used to extract information from the various sources, and the uncertainties involved in the data, are also presented in Appendix B.

It is noted that, although the production emission factor for the Conventional San Juan basin is relatively high, the forecasted production volumes for that basin are insignificant, relative to those of the San Juan Shale basin.

[3]Exhibit 4-2: Production and Gathering/Processing GHG emission factors for the



[3] Conventional natural gas is extracted via vertical wells in high permeability formations that do not require stimulation technologies for primary production. Shale gas is extracted from low permeability formations and require hydraulic fracturing and horizontal drilling. Tight gas is extracted from non-shale, low permeability formations and requires hydraulic fracturing and directional drilling (Littlefield *et al*., 2019).

4.2. Greenhouse Gas Emission Factor from Natural Gas Transmission

During the transmission of natural gas by pipeline, a portion of the natural gas is combusted in compressors, part of the gas is vented, while some is lost as fugitive emissions from equipment (such as flanges, connectors and valves) malfunctions that is not performing as designed. Pipeline transportation emissions make up a relatively small portion of overall GHG emissions over natural gas life cycle, and minor adjustments to transmission emission rates would result in insignificant differences (Pace Global, 2015). To determine the emissions factor resulting from local transmission of natural gas, the DOE/NETL report (Roman-White *et al*., 2019) used a pipeline distance of 971 km as the average distance from the natural gas extraction site to LNG terminals. They stated that this is the average distance of natural gas pipeline transmission in the United States, and is based on the characteristics of the entire transmission network and delivery rate for natural gas in the United States. As stated earlier, they have also assumed that the natural gas-fired power plant in the import destinations is located close to the LNG port, such that no additional pipeline transport of natural gas is needed to be modeled in the destination country. This report has adopted the same assumption for the gas transmission in the destination country. Based on their modeling, Roman-White *et al*. (2019) have calculated a total (expected) transmission emission factor of 60 g CO_2-e/kWh.

Pace Global (2015) however models GHG emissions from two separate stages of pipeline transport. The first stage for natural gas transmission from the processing plant to liquefaction facility and the second from LNG receiving/import terminal (after regasification in the destination country) to the power generation plant. In their model, both of these transport stages have the same analytical methodology and assumptions, except for the distance the natural gas travels during the two stages. Similar to the modeling performed by Roman-White *et al*. (2019) their model considered emissions from pipeline fugitive emissions and compressors, in addition to fugitive venting resulting from pipeline equipment release of methane to the atmosphere. Exhibit 4-3 below presents emissions factors from modeling performed by Pace Global (2015) for both stages of gas transmission. However, the CO_2 equivalent emissions from CH_4 and N_2O have been calculated using the GWP factors of 36 and 298 for CH_4 and N_2O, respectively, which are different from those used in the Pace Global (2015) report. With magnitude of the individual GHG from the different emission sources available, a scale-up of the total emissions resulting from the first transmission stage (@ 320 km) was performed, which resulted in the same value of total emissions for the second transmission stage (@ 1000 km).

Exhibit 4-3: Gas Transmission GHG emission factors in kg CO2-e/kg NG Transported.

	Natural Gas Transmission to the Liquefaction Plant Gate (@ 320 km)			Natural Gas Transmission from the LNG Receiving Terminal to the Power Generation Plant Gate (@ 1000 km)		
	Combusted - Compressor	Indirect - Electricity from Grid	Fugitive - Pipeline	Combusted - Compressor	Indirect - Electricity from Grid	Fugitive - Pipeline
	kg CO_2-e/kg Transported NG	kg CO_2-e/kg Transported NG	kg CO_2-e/kg Transported NG	kg CO_2-e/kg Transported NG	kg CO_2-e/kg Transported NG	kg CO_2-e/kg Transported NG
CO_2	8.34E-03	2.38E-04		2.61E-02	2.38E-04	
CH_4		4.67E-09	1.72E-03		4.67E-09	5.37E-03
N_2O	3.55E-08	3.53E-09		1.39E-07	3.53E-09	
Total	**8.35E-03**	**2.39E-04**	**6.19E-02**	**2.61E-02**	**2.39E-04**	**1.93E-01**

The distances between the Rocky Mountain Basins and the proposed Liquefaction plants at Jordan Cove and Costa Azul vary, thus the emissions factors have been calculated using distances of 1000, 1500 and 2000 km with the lowest and highest values used to bound the uncertainties. The results are presented in Exhibit 4-4.

Exhibit 4-4: Gas Transmission GHG emission factors in kg CO2-e/kg NG Transported for different Distances.

	Transmission Emission Factor	
	kg CO_2-e/kg Transported NG	g CO_2-e/kWh Electricity Generated
Total @1000 km pipeline length	0.2203	34.38
Total @1500 km pipeline length	0.3305	51.56
Total @2000 km pipeline length	0.4407	68.75

4.3. Greenhouse Gas Emissions Factor from Liquefaction

During the liquefaction stage, the pipeline quality gas is pre-treated by removing CO_2, H_2S, water and heavy hydrocarbons from the gas. This makes the gas suitable for liquefaction and prevents freezing and plugging in the downstream units. The pre-treated gas is then liquefied by cooling it down to approximately -160°C (API, 2015) and stored until it is ready for loading. Boil-off gas, which is generated during storage, is continuously removed and re-liquefied to maintain the temperature in the storage tanks (Roman-White *et al*., 2019). Based on the modeling parameters used by Roman-White *et al*. (2019), an emission factor of 41 g CO_2-e/kWh was determined for this process.

Pace Global (2015) analyzed several liquefaction scenarios of the liquefactions process based on the type of liquefaction technology, the type of refrigerant compressors used, the power source for plant electrical demand, and the option of a natural gas liquids (NGL) recovery unit. They evaluated four separate liquefaction processes, each of which entail two different scenarios, (i) assuming no NGL recovery, and (ii) assuming NGL recovery. Information on the specific power consumption (kWh/tonne of LNG produced) for liquefaction and the resulting quantity of LNG produced per hour, given the specific mode of power generation were used to model the emissions from each combination of liquefaction process and power generation source. To protect confidentiality, an anonymous naming convention was used so that specific assumptions and calculated results are not directly associated with any of the sources of proprietary liquefaction process technologies and do not affect the overall results on emission estimates.

While a summary of the relevant inputs used for each iteration of the liquefaction process are presented in the Pace Global (2015) report, a summary of GHG emissions factors calculated for each scenario based on the GWPs adopted in this study, are presented in Exhibit 4-5 below.

Based on the results in Exhibit 4-5, an average U.S. fleet plant efficiency of 46.4% (Roman-White *et al*., 2019), and an LNG energy content of 51.5 GJ/tonne, liquefaction emission factors calculated for this study are shown in Exhibit 4-6 below and range from 36.3 to 56.7 g CO_2-e/kWh, for the four different process and ten different scenarios, with the average being 45.8 g CO_2-e/kWh. For all the scenarios, power generation for each of the power sources and the resulting GHG emissions were included in the model. And for the electric grid-sourced power case, emissions were assumed to be equal to the average CO_2-e emissions from the U.S. grid (Pace Global 2015). Without direct knowledge of the process or scenario that would be adopted by the USWC LNG liquefaction plants, the range was used to bound the uncertainty for this stage of this study.

Exhibit 4-5: Summary of GHG emission factors from different Scenarios of the Liquefaction Process, in kg CO2-e/kg LNG.

	2 X GE Frame 7EA Gas Turbines, No Waste Heat Recovery, No NGL Recovery (kg CO_2-e/kg LNG)	2 X GE Frame 7EA Gas Turbines, No Waste Heat Recovery, With NGL Recovery (kg CO_2-e/kg LNG)	2 X GE Frame 7EA Gas Turbines, With Waste Heat Recovery, No NGL Recovery (kg CO_2-e/kg LNG)	2 X GE Frame 7EA Gas Turbines, With Waste Heat Recovery, With NGL Recovery (kg CO_2-e/kg LNG)	5 X GE LM2500+G4 Gas Turbines, No Waste Heat Recovery, No NGL Recovery kg CO_2-e/kg LNG)	5 X GE LM2500+G4 Gas Turbines, No Waste Heat Recovery, With NGL Recovery (kg CO_2-e/kg LNG)	5 X GE LM2500+G4 Gas Turbines, With Waste Heat Recovery, No NGL Recovery (kg CO_2-e/kg LNG)	5 X GE LM2500+G4 Gas Turbines, With Waste Heat Recovery, With NGL Recovery (kg CO_2-e/kg LNG)	Electric Motors, No NGL Recovery (kg CO_2-e/kg LNG)	Electric Motors, With NGL Recovery kg CO_2-e/kg LNG)
Process A	0.326	0.382	0.262	0.31	0.31	0.364	0.259	0.305	0.309	0.364
Process B	0.326	0.382	0.262	0.31	0.31	0.364	0.259	0.305	0.309	0.364
Process C	0.342	0.398	0.272	0.32	0.325	0.379	0.269	0.315	0.324	0.378
Process D	0.323	0.379	0.26	0.308	0.306	0.359	0.255	0.302	0.307	0.363

Exhibit 4-6: Summary of GHG emission factors from different Scenarios of the Liquefaction Process, in g CO2-e/kWh.

	2 X GE Frame 7EA Gas Turbines, No Waste Heat Recovery, No NGL Recovery (g CO_2-e/kWh)	2 X GE Frame 7EA Gas Turbines, No Waste Heat Recovery, With NGL Recovery (g CO_2-e/kWh)	2 X GE Frame 7EA Gas Turbines, With Waste Heat Recovery, No NGL Recovery (g CO_2-e/kWh)	2 X GE Frame 7EA Gas Turbines, With Waste Heat Recovery, With NGL Recovery (g CO_2-e/kWh)	5 X GE LM2500+G4 Gas Turbines, No Waste Heat Recovery, No NGL Recovery (g CO_2-e/kWh)	5 X GE LM2500+G4 Gas Turbines, No Waste Heat Recovery, With NGL Recovery (g CO_2-e/kWh)	5 X GE LM2500+G4 Gas Turbines, With Waste Heat Recovery, No NGL Recovery (g CO_2-e/kWh)	5 X GE LM2500+G4 Gas Turbines, With Waste Heat Recovery, With NGL Recovery (g CO_2-e/kWh)	Electric Motors, No NGL Recovery (g CO_2-e/kWh)	Electric Motors, With NGL Recovery (g CO_2-e/kWh)
Process A	46.41	54.38	37.30	44.13	44.13	51.82	36.87	43.42	43.99	51.82
Process B	46.41	54.38	37.30	44.13	44.13	51.82	36.87	43.42	43.99	51.82
Process C	48.69	56.66	38.72	45.56	46.27	53.95	38.29	44.84	46.12	53.81
Process D	45.98	53.95	37.01	43.85	43.56	51.11	36.30	42.99	43.70	51.68

4.4. Greenhouse Gas Emissions Factor from Loading, Shipping and Unloading Operations

The stored LNG has to be transported (aka shipping) from the liquefaction facility at the origin to regasification facility at the destination. This is achieved by loading the stored LNG on to an ocean tanker for transportation and then unloaded into storage tanks at the regasification facility after ocean transport.

While Roman-White *et al*. (2019) have separated the emissions resulting from loading and unloading operations from ocean transport, Pace Global (2015) have modeled emissions resulting from LNG shipping (aka transporting) to include ship loading, the laden voyage, ship offloading, and the ballast voyage. They have calculated LNG shipping emissions based on four different types of ship design, depending on the (i) type of fuel combusted, the (ii) amount of feed LNG that can be transported in one laden voyage, (iii) the distance travelled, and (iiii) the amount of fuel required over the course of both the laden and the ballast voyages. Based on the key the modeling parameters for loading/unloading and ocean transport used by Roman-White *et al*. (2019), and with shipping routes between New Orleans, U.S. and Shanghai, China that vary between 18,544 and 31,722 km (depending on the route taken), a base emission factor of 76 g CO_2-e/kWh has been determined for tanker transport (which includes emissions from loading/unloading operations). In this study, the distance from USWC LNG is much shorter (about 9,542 km from Coos Bay, U.S. to Shanghai, China), and that reduction of 9,002 km to 22,180 km has been factored in the estimated emission factor for purpose herein.

However, Pace Global (2015) have reported the individual GHG emission for four different types of ship design for the laden voyage, ballast voyage, and loading/unloading operations. The ship design will determine the amount and type of fuel combusted and the amount of feed LNG that can be transported in one laden voyage. In addition, the distance between the origin and the destination will influence the amount of GHG emissions which in turn determines the amount of fuel required over the course of both the laden and ballast voyages. Based on the GHG factor emissions published by Pace Global (2015) for the different ship designs, the distances between the origin and the various destinations used in this report, and the GWPs applied in this report, the emissions factors presented in Exhibit 4-7 have been determined.

Exhibit 4-7: Summary of GHG emission factors from LNG Loading, Shipping, and Unloading Operation, in g CO2-e/kWh.

From	USWC				
To	China ($g\ CO_2$-e/kWh)	India ($g\ CO_2$-e/kWh)	Japan ($g\ CO_2$-e/kWh)	South Korea ($g\ CO_2$-e/kWh)	Taiwan ($g\ CO_2$-e/kWh)
Moss	21.52	34.71	17.23	21.27	23.02
DFDE Membrane	18.39	29.76	14.69	18.18	19.68
Q-Flex Membrane	17.90	28.91	14.31	17.69	19.15
Q-Max Membrane	18.96	30.69	15.15	18.75	20.29

4.5. Greenhouse Gas Emissions Factor from Regasification

After unloading from the LNG tanker, the imported LNG is regasified at the facility by turning it into a pressurized, gaseous state to make it suitable for pipeline transportation to the end-user, in this case, the power plant, where it is combusted to generate power. Details of the regasification process are presented by both Roman-White *et al*. (2019) and Pace Global (2015). While Roman-White *et al*. (2019) have calculated an emission factor of 4 g CO_2-e/kWh for the regasification stage, based on their model inputs and modeling, Pace Global (2015) have presented the total CO2 emission rates per unit mass of regasified natural gas for five different regasification plant options. They modeled emissions from power consumption for both the simple and combined cycle power sources and also for the cases where the power source is assumed to be the local grid for the countries India, China, South Korea and Japan. Based on the assumption that energy for regasification is sourced from local grid electricity, the calculated total emissions from the regasification stage for the Pace Global (2015) model varied between 1.49 and 2.84 g CO_2-e/kWh, for the four import countries mentioned above and are shown in Exhibit 4-8 below. For this stage of the life cycle, China figures were adopted for Taiwan.

The regasification plant options analyzed by Pace Global (2015) are:

» Seawater-heated open rack vaporizers (ORV).

» Submerged combustion vaporizers (SCV).

» Air-heated vaporization using a closed loop glycol / water system heated by air (AHV).

» Air-heated vaporization using and an open loop air-heated water system, also known as Shell & Tube Vaporizer with air exchange tower (STV + AET).

» LNG vaporization via waste heat from a co-located power plant (HRV).

[4] In a simple cycle plant, compressed air and natural gas are combusted to produce a hot gas stream used to spin a generator to produce electricity. In a combined cycle, waste heat generated from the gas turbine exhaust is used to produce steam to power a steam turbine-drive generator, in addition to the gas turbine-driven generator of the simple cycle plant.

Exhibit 4-8: Summary of GHG emission factors from LNG Regasification Stage, in g CO2-e/kWh.

	Grid – China ($g CO_2$-e/kWh)	Grid – India ($g CO_2$-e/kWh)	Grid – Japan ($g CO_2$-e/kWh)	Grid - South Korea ($g CO_2$-e/kWh)
ORV	2.67	2.84	1.65	1.75
SCV	2.64	2.81	1.64	1.73
AHV	2.48	2.64	1.49	1.62
STV+AET	2.53	2.68	1.56	1.65
HRV	2.53	2.68	1.56	1.65

4.6. Greenhouse Gas Emissions Factor from Power Plant Operations

This segment of the life cycle is defined by the entry of the natural gas from the regasification facility through pipelines to the power plant for the generation of a unit (kWh) of gas-fired electricity. The heat rate or the efficiency of the power plant is mostly dependent on the process the plant uses to turn the turbines that generate electricity (Pace Global, 2015). Key modeling parameters used by Roman-White *et al*. (2019) for power plant emissions are the plant net efficiencies of 41.2%, 46.4% and 49.2% for the low, expected, and high values. These values represent the range of efficiencies of fleet baseload gas-fired power plants in the United States, with 46.6% being the average baseload efficiency. The same range has been assumed to be the range of power plant efficiencies in the destination countries in their analysis, yielding an expected emission factor of 416 CO_2-e/kWh for the power plant operations.

Pace Global (2015) have examined two main categories of gas-fired power plants in their analysis; the simple cycle and the combined cycle gas turbine-driven power plants, the latter of which represent the majority of gas-fired power plants currently in operation. While simple cycle plants are of older technology and less efficient, combined cycle plants are more modern and more efficient. However, simple cycle power plants have an advantage of being cheaper and faster to install and have the ability to reach full power in a shorter time frame, an advantage that makes them more suitable for peak-load power generation. Despite that, power plant developers are less likely to design and install new simple cycle power plants due to the relatively high fuel consumption rate, compared to the combined cycle power plants. (Pace Global, 2015). The GHG emissions calculated for simple cycle and combined cycle power plants using the individual GHG emission intensities calculated by Pace Global (2015) and the GWPs adopted in this study are presented in Exhibit 4-9 below.

The emission factor for the combined cycle has been adopted as the low GHG (365.16 g CO2-e/kWh) case in this study, while that resulting from modeling utilizing the average baseload efficiency has been adopted as the high GHG (416 g CO_2-e/kWh) case.

Exhibit 4-9: Summary of GHG Emission Factors from Power Plant Operations, in g CO2-e/kWh.

	Combined Cycle (g CO_2-e/kWh)	Simple Cycle (g CO_2-e/kWh)
CO_2 EF for Auxiliary Boilers	0.46	0.71
CO_2 EF for Turbines	364.70	560.00
Total	**365.16**	**560.71**

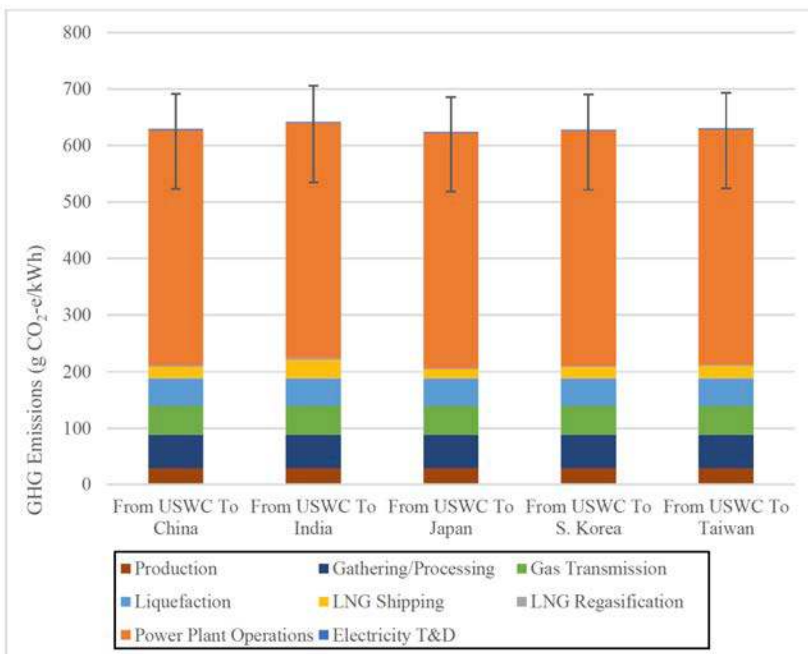
4.7. Greenhouse Gas Emissions Factor from Electricity Transmission and Distribution (T&D)

Roman-White *et al*. (2019) state that the transmission and distribution of electricity using existing electricity transmission and distribution infrastructure incur a loss of 7% of electrical energy during the process and have accounted for this with an emission factor of 2 CO_2-e/kWh in their model. This has been adopted for this study as well.

5. Greenhouse Gas Emissions Factor for Life Cycle of USWC LNG Supply Chain

Based on the results of the individual life cycle stages of the LNG supply chain (from Rockies natural gas production) determined in the preceding sections, the life cycle emission factors for exporting USWC LNG for electricity generation in the potential import countries considered is presented in Exhibit 5-1 below. Results show that the expected values life cycle emission factors range from 624 to 642 g CO_2-e/kWh with export to Japan having the lowest expected life cycle emission factor and India having the highest. Expectedly, the power plant operations stage of the life cycle is the most carbon-intensive stage of the life cycle, contributing between 64.8% and 66.6% of the life cycle emissions, with highest proportion in Japan and the lowest in India.

Exhibit 5-1: Life GHG Emission Factors for USWC LNG Export for Electricity Generation, in g CO2-e/kWh.



6. Effect of Displacing Local Coal-Generated Electricity in Import Countries by USWC LNG

Studies (Roman-White *et al*., 2019; Kasumu *et al*., 2018; Pace Global, 2015) have performed different analyses on the life cycle emissions emanating from coal-generated electricity in the countries considered in this study. Life cycle emissions of domestic coal-generated electricity from such studies have been used to determine the net effects of the displacement of the domestic coal-generated electricity by USWC LNG in the importing countries of China, India, Japan, South Korean and Taiwan. The net effect of the displacement of coal-generated electricity in selected potential import countries, by 22.8 MTPA of USWC LNG are presented in this section. Exhibit 6-1 shows that the expected portion of the coal-generated electricity that is displaced by USWC LNG is very small in China (3.3%), and to a greater extent in India (13.5%), absolute reductions in coal electricity emissions are correspondingly small (1.4% and 6.7% reduction respectively). However, a doubling of the export quantity would invariably lead to a doubling of these percent reductions, with all other factors being the same and demonstrate significant opportunity for reductions in net emissions with additional disruption of coal-generated electricity.

However, when the life cycle emissions are considered, reductions ranging from 42% to 55% can be expected when using natural gas versus coal for electricity generation. These would not change even if the export capacity of USWC LNG is increased, with all other factors being the same. If all the 22.8 MTPA (proposed capacity) of USWC LNG were exported to China and used to displace coal-fired electricity, this study expects a net reduction of 71.4 MT CO2-e/yr If all of the USWC LNG were exported to other countries to displace coal-fired electricity, expected GHG reductions would be 99.9, 106.6, 119.6, and 67.2 MT CO_2-e/yr in India, Japan, South Korea, and Taiwan, respectively.

Exhibits 6-2 to 6-6 compare the calculated life cycle GHG emissions of USWC LNG to the life cycle GHG emissions of coal electricity in the respective import countries on a 100-yr GWP basis..

Exhibit 6-1: Change in GHG Emissions Resulting from Export of 22.8 MTPA of USWC LNG to Displace Coal Electricity in Different Import Countries.

	Quantity of Coal Electricity that can be	% of Import Country's Coal Electricity	Change in Import Country's Coal Emissions Factor after	% Difference in Coal Emissions after	Baseline % Change in Import Country's Life Cycle Emissions Factor after	Difference in Coal Electricity Emissions after Coal Electricity Displacement (MT CO2-e/yr)
China	157	3.3	-15	-1.4	-42.0	-71.4
Taiwan	131	119.4	-370	-37.0	-44.0	-48.6
India	157	13.5	-86	-6.7	-49.8	-99.9
Japan	157	46.3	-315	-24.1	-52.1	-106.6
S. Korea	157	60.7	-463	-33.3	-54.8	-119.6

Exhibit 6-2: Comparison between Life Cycle Emission Factors of USWC LNG and Coal Electricity in China, resulting from Export of 22.8 MTPA of USWC LNG.

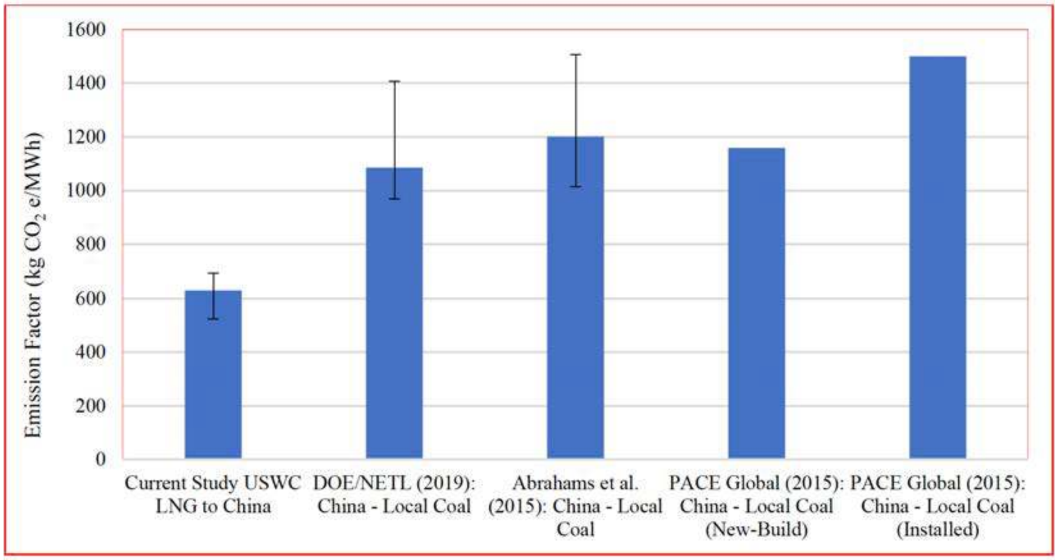


Exhibit 6-3: Comparison between Life Cycle Emission Factors of USWC LNG and Coal Electricity in India, resulting from Export of 22.8 MTPA of USWC LNG.

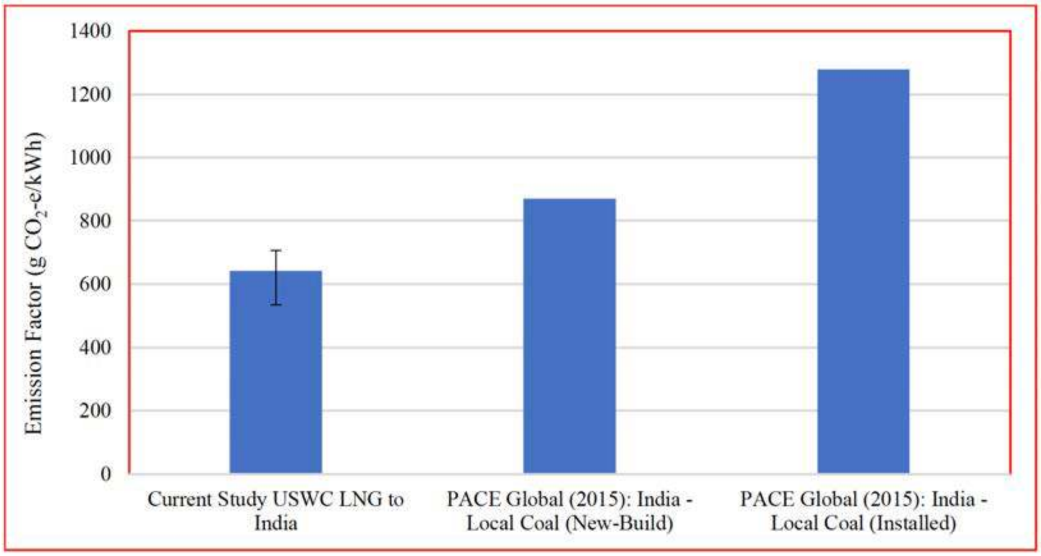


Exhibit 6-4: Comparison between Life Cycle Emission Factors of USWC LNG and Coal Electricity in Japan, resulting from Export of 22.8 MTPA of USWC LNG.

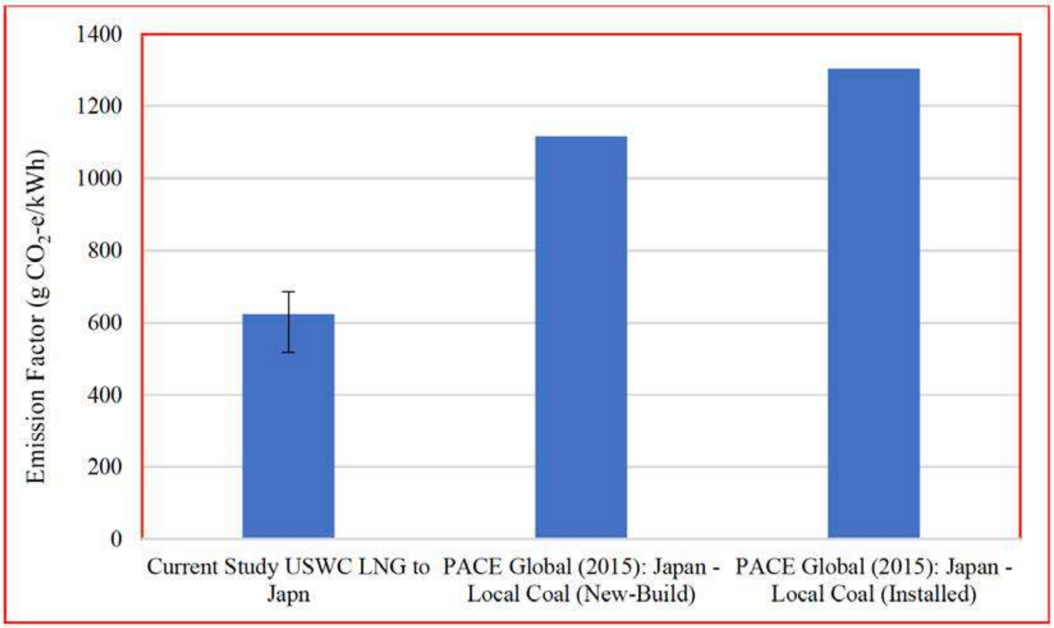


Exhibit 6-5: Comparison between Life Cycle Emission Factors of USWC LNG and Coal Electricity in China, resulting from Export of 22.8 MTPA of USWC LNG.

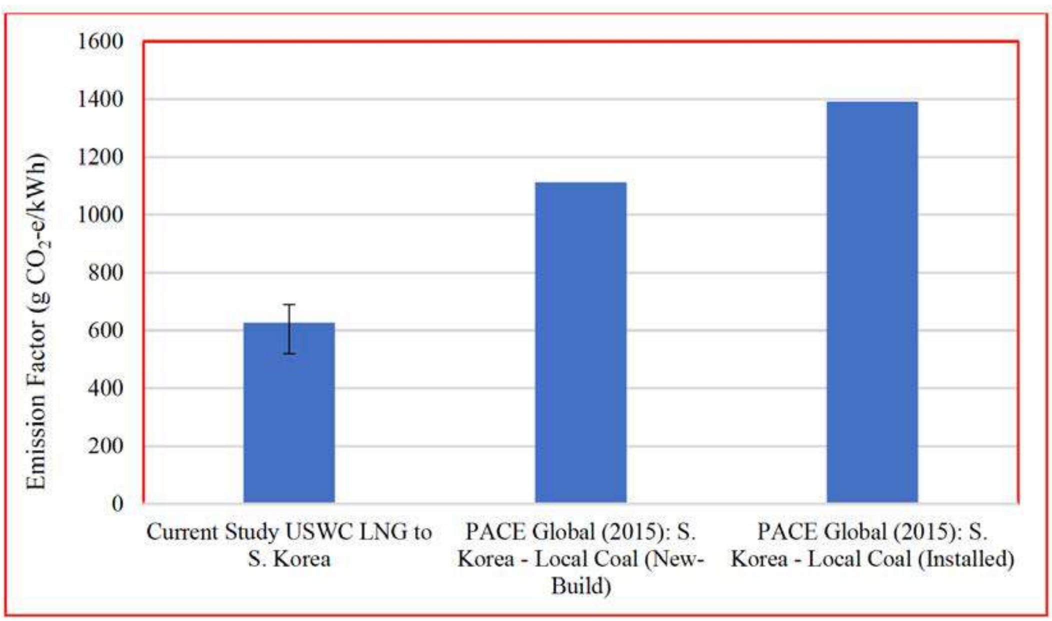
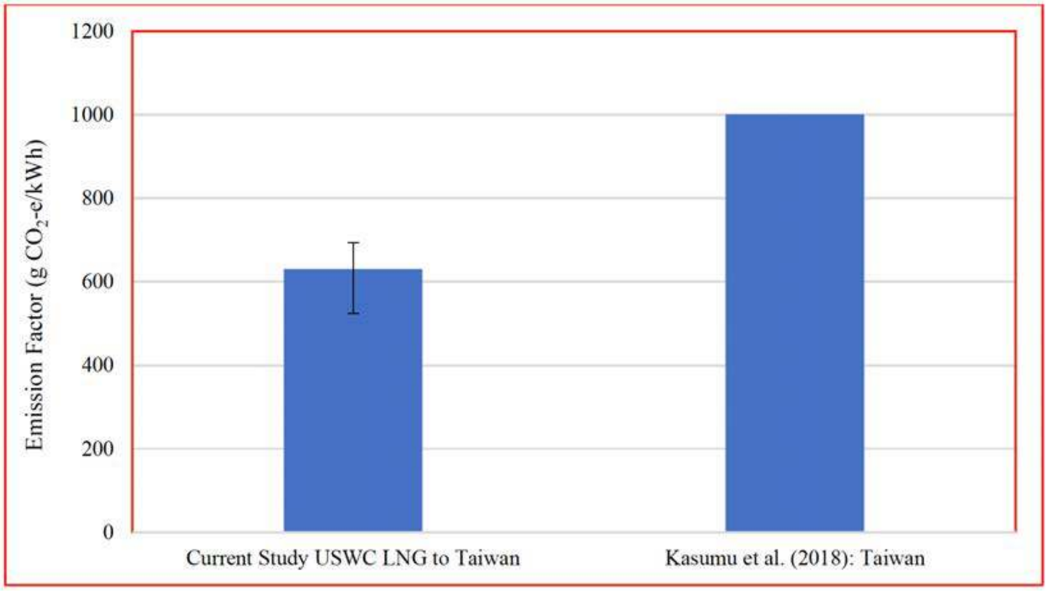


Exhibit 6-6: Comparison between Life Cycle Emission Factors of USWC LNG and Coal Electricity in China, resulting from Export of 22.8 MTPA of USWC LNG.



7. Summary and Conclusions

Data from published studies were used to develop life cycle emissions for exporting LNG to certain Asian Markets to displace coal-fired electricity generation, with the natural gas specifically sourced from the U.S. Rocky Mountain Basins and exported from the West Coast of North America using the Pacific Ocean route. The analysis has determined that the use of USWC LNG exports for electricity generation in Asian markets have a significant net GHG emissions reductions from a life cycle perspective, when compared to local coal extraction and use for electricity generation. Specifically, 42.0%, 49.8%, 52.1%, 54.8% and 44.8% for China, India, Japan, S. Korea, and Taiwan, respectively.

The results show that based on a 100-yr time period, the generation of electricity from natural gas imported from the U.S. Rocky Mountain Basins has lower life cycle GHG emissions than electricity generation from local coal in all potential import countries considered in Asia. With the expected 22.8 MTPA LNG proposed to be exported, analyses show a relatively small amount (3.3%) of the coal-fired electricity generated in China is expected to be displaced, with a net GHG reduction of about 71.4 MT CO_2-e MT/yr The size of this emissions reduction would consequently double if the quantity of displaced coal-fired electricity were to double, and demonstrates the significant benefits of replacing China's coal use with additional LNG. Higher percentages of net GHG reductions were estimated for other Asian countries considered, with the same quantity of LNG, due to its ability to displace higher proportions of the coal-fired electricity in those countries.

When the uncertainties considered in this study are factored in, there is no overlap between the USWC LNG to Asia and the local coal scenarios for all countries considered. This means that the highest value of the life cycle emissions from the gas-fired electricity (from USWC LNG) would still be lower than the lowest value of the life cycle emissions from the local coal-fired electricity in the importing countries. The relatively shorter ocean distances of the Pacific route for shipping from the West Coast of North America to the Asian nations helps to lower the life cycle GHG emissions of the LNG supply chain. Results of this study also show that there are enough idle proved reserves in the Rocky Mountain Basins to support the proposed USWC LNG exports, even while the natural gas continues to be produced and marketed from the Rocky Mountain Basins at 2017 levels without drilling for replacement reserves.

Global demand for LNG is forecast to almost double by 2040, with Asian countries expected to drive roughly 75% of that growth, and more medium- and long-term LNG contracts are being executed. (Shell, 2021) In this market context, natural gas from the U.S. Rocky Mountain Basins can contribute to significant bridge fuel measures and alternative energy transitions away from coal. In summary, this will help to achieve global targets in GHG reductions and foster economic activity in the U.S. at the same time.

8. References

Anna, Lawrence O. 2010. „Geologic Assessment of Undiscovered Oil and Gas in the Powder River Basin Province, Wyoming and Montana.“ In *Total Petroleum Systems and Geologic Assessment of Oil and Gas Resources in the Powder River Basin Province, Wyoming and Montana*, by L O Anna, 1-96. Reston, VA: U.S. Geological Survey.

Climate Action Tracker. 2021. *CAT comment on China's 14th Five Year Plan*. March 5. Accessed April 12, 2021. https://climateactiontracker.org/press/cat-comment-on-chinas-14th-five-year-plan/.

Drake II, Ronald M, Christopher J Schenk, Tracey J Mercier, Phuong A Le, Thomas M Finn, Ronald C Johnson, Cheryl A Woodall, *et al*. 2019. *Assessment of Undiscovered Continuous Tight-Gas Resources in the Mesaverde Group and Wasatch Formation, Uinta-Piceance Province,Utah and Colorado, 2018.* National and Global Petroleum Assessment, Reston, VA: U.S. Geological Survey,
2. doi:https://doi.org/10.3133/fs20193027.

DrillingInfo. 2018. „DI Data & Insights.“

EIA. 2018. *Natural Gas Gross Withdrawals and Production.* Energy Information Administration. https://www.eia.gov/dnav/ng/ng_prod_sum_dc_NUS_mmcf_m.htm.

Finn, Thomas M, Christopher J Schenk, Tracey J Mercier, Marilyn E Tennyson, Phuong A Le, Michael E Brownfield, Kristen R Marra, *et al*. 2019. *Assessment of continuous oil and gas resources in the niobrara interval of the Cody Shale, Bighorn Basin Province, Wyoming and Montana, 2019.* USGS Numbered Series, Reston, VA: U.S. Geological Survey,
2. doi:https://doi.org/10.3133/fs20193045.

Finn, Thomas M, Christopher J Schenk, Tracey J Mercier, Marilyn E Tennyson, Phuong A Le, Michael Brownfield, Kristen R Marra, *et al*. 2018. *Assessment of Continuous Oil and Gas Resources in the Niobrara Interval of the Cody Shale, Wind River Basin Province, Wyoming, 2018.* USGS Numbered Series, Reston, VA: U.S. Geological Survey,
2. doi:https://doi.org/10.3133/fs20183076.

Global, Pace. 2015. *LNG and Coal Life Cycle Assessment of Greenhouse Gas Emissions.* Report, Fairfax, VA: Pace Global, A Siemens Business. http://www.paceglobal.com/wp-content/uploads/2015/10/LNG-and-Coal-Life-Cycle-Assessment-of-Greenhouse-Gas-Emissions.pdf.

Grant, John, Rajashi Parikh, and Amnon Bar-Ilan. 2018. *Future Year 2028 Emissions from Oil and Gas Activity in the Greater San Juan Basin and Permian Basin Final Report.* Santa Fe, NM: Ramboll Environ. http://www.wrapair2.com/pdf/SanJuan_Permian_Futureyear_EI_Report_21Aug2018.pdf.

Grant, John, Rajashi Parikh, James King, and Amnon Bar-Ilan. 2018. *San Juan and Permian Basin 2014 Oil and Gas emission Inventory Inputs.* Final Report, Santa Fe, NM: Prepared for Bureau of Land Management, Western States Air Resources Council & Regional Air Partnership and Ramboll Environ.

Hawkins, Sarah J, Ronald R Charpentier, Christopher J Schenk, Heidi M Leathers-Miller, Timothy R Klett, Michael E Brownfield, Tom M Finn, *et al*. 2016. *Assessment of continuous (unconventional) oil and gas resources in the Late Cretaceous Mancos Shale of the Piceance Basin, Uinta-Piceance Province, Colorado and Utah, 2016.* USGS Numbered Series, Reston, VA: U.S. Geological Survey, 4. doi:https://doi.org/10.3133/fs20163030.

Higley, Debra K, Ronald R Charpentier, Troy A Cook, Timothy R Klett, Richard M Pollastro, and James W Schmoker. 2007. „Executive Summary—2002 Assessment of Undiscovered Oil and Gas in the Denver Basin Province, Colorado, Kansas, Nebraska, South Dakota, and Wyoming." Chap. 1 in *Petroleum systems and assessment of undiscovered oil and gas in the Denver Basin Province, Colorado, Kansas, Nebraska, South Dakota, and Wyoming,* by D K Higley, 1-4. Reston, VA: USGS Province 39: U.S. Geological Survey Digital Data Series DDS–69–P.

Higley, Debra K, Troy A Cook, Richard M Pollastro, Ronald R Charpentier, Timothy R Klett, and Christopher J Schenk. 2007. „Executive Summary—2005 Assessment of Undiscovered Oil and Gas Resources in the Raton Basin–Sierra Grande Uplift Province of Colorado and New Mexico." Chap. 1 in *Petroleum Systems and Assessment of Undiscovered Oil and Gas in the Raton Basin–Sierra Grande Uplift Province, Colorado and New Mexico—USGS Province 41*, by Debra K Higley, 1-2. Reston, VA: U.S. Geological Survey Digital Data Series DDS–69–N.

International Group of Liquefied Natural Gas. 2020. *The LNG industry: GIIGNL Annual Report 2020 Edition.* Annual Report, Neuilly-sur-Seine, France: International Group of Liquefied Natural Gas Importers (GIIGNL). Website: www.giignl.org.

International Energy Agency. 2020. *Electricity Information: Overview (2020 Edition).* Statistics Report:, Paris, France: IEA Publications.

Kasumu, Adebola S, Vivian Li, James W Coleman, Jeanne Liendo, and Sarah M Jordaan. 2018. „Country-Level Life Cycle Assessment of Greenhouse Gas Emissions from Liquefied Natural Gas Trade for Electricity Generation." *Environ. Sci. Technol* 52 (4): 1735-1746. doi:https://doi.org/10.1021/acs.est.7b05298.

Littlefield, James, Dan Augustine, Ambica Pegallapati, George G Zaimes, Srijana Rai, Gregory Cooney, and Timothy J Skone. 2019. *Life Cycle Analysis of Natural Gas Extraction and Power Generation.* Pittsburgh: NETL. https://www.netl.doe.gov/energy-analysis/details?id=3198.

Moore , Michal, David Hackett, Leigh Noda, Jennifer Winter, Roman Karski, and Mark Pilcher. 2014. *Risky Business: The Issue of Timing, Entry and Performance in the Asia-Pacific LNG Market.* The

School of Public Policy Publications, University of Calgary, Calgary, AB: SPP Research Papers. doi:https://doi.org/10.11575/sppp.v7i0.42470

Oil & Gas Journal. 2021. „Shell expects global LNG demand to almost double by 2040." *Oil & Gas Journal*, March 8: 14-14.

Reuters. 2021. Energy. April 23. Accessed May 28, 2021. https://www.reuters.com/business/energy/pembina-pauses-development-oregon-jordan-cove-lng-plant-2021-04-23/.

Roman-White, Selina, Srijana Rai, James Littlefield, Gregory Cooney, and Timothy J Skone. 2019. *Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States: 2019 Update - DOE-NETL-2019-2041 - Skone et al*. Pittsburgh, PA: National Energy Technology Laboratory.

Schenk, Christopher J, Tracey J Mercier, Thomas M Finn, Kristen R Marra, Phuong A Le, Heidi M Leathers-Miller, Janet K Pitman, Michael E Brownfield, and Ronald M Drake II. 2019. *Assessment of Continuous Gas Resources in the Permian Phosphoria Formation of the Southwestern Wyoming Province, Wyoming, 2019.* National and Global Petroleum Assessment, Reston, VA: U.S. Geological Survey.
doi:https://doi.org/10.3133/fs20193047.

sea-distances.org. 2021. https://sea-distances.org/. Accessed January 12, 2021. https://sea-distances.org/.

The White House. 2021. *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis.* January 20. Accessed April 7, 2021. https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/20/executive-order-protecting-public-health-and-environment-and-restoring-science-to-tackle-climate-crisis/.

U.S. Energy Information Administration. 2020. *U.S. EIA: Frequently Asked Questions (FAQS)*. December 15. Accessed January 18, 2021. https://www.eia.gov/tools/faqs/faq.php?id=74&t=11.

U.S. Geological Survey. 2005. *Assessment of undiscovered oil and gas resources of the Wind River basin province, 2005*. USGS Numbered Series, Denver, CO: U.S. Geological Survey. doi:https://doi.org/10.3133/fs20053141.

USGS San Juan Basin Assessment Team. 2013. „Executive Summary—2002 Assessment of Undiscovered Oil and Gas Resources in the San Juan Basin Province, Exclusive of Paleozoic Rocks, New Mexico and Colorado." Chap. 1 in *Total Petroleum Systems and Geologic Assessment of Undiscovered Oil and Gas Resources in the San Juan Basin Province, Exclusive of Paleozoic Rocks, New Mexico and Colorado*, by USGS San Juan Basin Assessment Team, 1-4. Reston, VA: U.S. Geological Survey Digital Data Series 69–F.

USGS Southwest Wyoming Province Assessment Team. 2005. *National Assessment of Oil and Gas Project: petroleum systems and geologic assessment of oil and gas in the Southwestern Wyoming Province, Wyoming, Colorado and Utah.* USGS Numbered Series, Denver, CO: U.S. Geological Survey. doi:https://doi.org/10.3133/ds69D.

USGS Uinta-Piceance Assessment Team. 2002. *Petroleum systems and geologic assessment of oil and gas in the Uinta-Piceance Province, Utah and Colorado.* USGS Numbered Series, Denver, Co: U.S. Geological Survey. doi:https://doi.org/10.3133/ds69B.

Vaughn, Timothy L, Clay S Bell, Tara I Yacovitch, Joseph R Roscioli, Scott C V, Stephen Conley, Stefan Schwietzke, Garvin A Heath, Gabrielle Pétron, and Daniel Zimmerle. 2017. „Comparing facility-level methane emission rate estimates at natural gas gathering and boosting stations." *Elementa: Science of the Anthropocene* 5: 71. doi:http://doi.org/10.1525/elementa.257.

Western Regional Air Partnership. n.d. *WESTAR 2014 Oil and Gas emissions Inventory for Greater San Juan Basin in Colorado and New Mexico Area.* Report, Ramboll. https://www.wrapair2.org/OGWG.aspx.

Whidden, Katherine J. 2012. *Assessment of Undiscovered Oil and Gas Resources in the Paradox Basin Province, Utah, Colorado, New Mexico, and Arizona, 2011: U.S. Geological Survey Fact Sheet 2012–3031.* U.S. Geological Survey Fact Sheet 2012–3031, Denver, CO: USGS. doi:https://doi.org/10.3133/fs2012303.

9. Appendix A: Undiscovered Gas Estimates

Exhibit A-1: Undiscovered gas estimates compiled from USGS assessment reports. Powder River (PR), Bighorn (BR), Wind River (WR), Greater Green River (GGR), Uinta-Piceance (UP), Uinta (UIN), Piceance (PIC), Paradox (PX), Denver-Julesburg (DJ), Raton (RT), San Juan (SJ), total petroleum system (TPS). "Continuous" gas accumulations are assumed to be synonymous with unconventional gas accumulations for the purpose of this report. F95, F50, F5 and Mean values are in BCFG. USGS source reports for F95, F50, F5 and Mean values listed in each row are cited in "Type" column with superscript. Data references listed below the table.

State(s)	Basin	Type [# -reference]	Formations	F95	F50	F5	Mean
WY	Powder River (PR)	Best estimate[1]	All	9,036.49	15,713.80	27,250.65	16,631.67
WY	Powder River (PR)	Conventional[1]	All	227.61	979.80	2,634.68	1,156.27
WY	Powder River (PR)	Continuous (unconventional)[1]	All	8,808.88	14,734.00	24,615.97	15,475.40
WY	Bighorn (BH)	Best estimate[2,3]	All	428.00	1,672.00	4,300.00	1,928.00
WY	Bighorn (BH)	Continuous(unconventional)[3]	Niobrara Intvl of Cody Shale	112.00	793.00	2,268.00	939.00
WY	Bighorn (BH)	Conventional[2]	All	117.00	402.00	885.00	439.00
WY	Bighorn (BH)	Continuous (unconventional)[2]	All	199.00	477.00	1,147.00	550.00
WY	Wind River (WR)	Best estimate[4,5]	All	1,368.00	3,679.00	8,939.00	4,224.00
WY	Wind River (WR)	Continuous (unconventional)[5]	Niobrara Intvl of Cody Shale	377.00	1,505.00	4,405.00	1,831.00
WY	Wind River (WR)	Conventional[4]	All	106.00	407.00	972.00	457.00
WY	Wind River (WR)	Continuous (unconventional)[4]	All	885.00	1,767.00	3,562.00	1,936.00
WY-CO	Greater Green River (GGR)	Best estimate[6,7]	All	53,399.60	81,223.50	127,207.20	84,589.90
WY-CO	Greater Green River (GGR)	Conventional[6]	All	610.70	2,088.70	5,376.30	2,420.80
WY-CO	Greater Green River (GGR)	Continuous (unconventional)[6]	All	52,788.90	79,134.80	121,830.90	82,169.10
WY-CO	Greater Green River (GGR)	Continuous (unconventional)[7]	Phosphoria	-	1,265.00	3,286.00	1,406.00
UT-CO	Uinta-Piceance (UP)	Best estimate[8,9,10]	All	40,934.71	85,072.12	158,574.01	90,577.20
UT-CO	Uinta-Piceance (UP)	Conventional[8]	All	63.71	191.12	436.01	213.20
UT-CO	Uinta-Piceance (UP)	Continuous (unconventional)[8]	All	12,145.49	20,121.39	33,978.81	21,211.03
UT-CO	Uinta-Piceance (UP)	Continuous (unconventional)[9]	Mesaverde and Wasatch	6,750.00	22,497.00	46,469.00	24,033.00

State(s)	Basin	Type	Formations	F95	F50	F5	Mean
UT	Uinta (UIN)	Best estimate[8,9]	All	7,316.73	21,282.59	42,432.11	22,537.41
UT	Uinta (UIN)	Conventional[8]	Green River TPS-associated gas	7.59	24.83	63.73	28.88
UT	Uinta (UIN)	Conventional[8]	Ferron/Wasatch Plateau TPS	10.73	35.91	81.23	39.75
UT	Uinta (UIN)	Continuous (unconventional)[8]	Ferron/Wasatch Plateau TPS	-	52.04	136.43	59.10
UT	Uinta (UIN)	Continuous (unconventional)[9]	Mesaverde and Wasatch	5,481.00	18,144.00	37,113.00	19,235.00
UT	Uinta (UIN)	Continuous (unconventional)[8]	Mancos/Mowry TPS	1,781.69	2,965.07	4,934.43	3,110.69
UT	Uinta (UIN)	Continuous (unconventional)[8]	Green River TPS-associated gas	35.72	60.74	103.29	63.99
CO	Piceance (PIC)	Best estimate[9,10]	All	35,390.00	66,737.00	121,025.00	71,039.00
CO	Piceance (PIC)	Continuous (unconventional)[9]	Mesaverde and Wasatch	1,269.00	4,353.00	9,356.00	4,708.00
CO	Piceance (PIC)	Continuous (unconventional)[10]	Mancos	34,121.00	62,384.00	111,669.00	66,331.00
UT-CO	Paradox (PX)	Best estimate[11]	All	6,429.00	11,915.00	21,623.00	12,701.00
UT-CO	Paradox (PX)	Conventional[11]	All	234.00	784.00	1,591.00	833.00
UT-CO	Paradox (PX)	Continuous (unconventional)[11]	All	6,195.00	11,131.00	20,032.00	11,868.00
CO-WY	Denver-Julesburg (DJ)	Best estimate[12]	All	1,312.33	2,287.54	4,455.30	2,518.74
CO-WY	Denver-Julesburg (DJ)	Conventional[12]	All	19.81	62.73	312.66	110.41
CO-WY	Denver-Julesburg (DJ)	Continuous (unconventional)[12]	All	1,292.52	2,224.81	4,142.64	2,408.33
CO-NM	Raton (RT)	Best estimate[13]	All	1,117.39	2,249.57	3,932.34	2,352.97
CO-NM	Raton (RT)	Conventional[13]	All	216.64	737.43	1,385.55	762.39
CO-NM	Raton (RT)	Continuous (unconventional)[13]	All	900.75	1,512.14	2,546.79	1,590.58

State(s)	Basin	Type	Formations	F95	F50	F5	Mean
CO-NM	San Juan (SJ)	Best estimate[14]	All	41,074.09	50,083.09	61,798.82	50,584.55
CO-NM	San Juan (SJ)	Conventional[14]	All	59.06	153.24	310.80	165.15
CO-NM	San Juan (SJ)	Continuous (unconventional)[14]	All	41,015.03	49,929.85	61,488.02	50,419.40
	Total	**Best estimate**	**All**	**156,871.63**	**256,843.09**	**422,963.42**	**269,107.24**
	Total	**Conventional**	**All**	**1,609.14**	**5,675.64**	**13,612.95**	**6,412.65**
	Total	**Continuous (unconventional)**	**All**	**155,262.49**	**251,167.45**	**409,350.47**	**262,694.59**

Exhibit A-1 source data references

[1] Anna (2010)

[2] Kirschbaum *et al*. (2010)

[3] Finn *et al*. (2019)

[4] USGS (2005)

[5] Finn *et al*. (2018)

[6] USGS Southwest Wyoming Province Assessment Team (2005)

[7] Schenk *et al*. (2019)

[8] USGS Uinta-Piceance Assessment Team (2002)

[9] Drake *et al*. (2019)

[10] Hawkins *et al*. (2016)

[11] Whidden *et al*. (2012)

[12] Higley *et al*. (2007a)

[13] Higley *et al*. (2007b)

[14] USGS San Juan Basin Assessment Team (2013)

10. Appendix B: Upstream Emissions Factors

1. Emission factors from the NETL report

The emission estimates were selected from NETL's life cycle natural gas model for all basins and gas types (conventional, shale, tight) where it provided estimates because it contained the most up-to-date, basin-specific information. Their model accounts for the variability among the different technologies used to extract natural gas and is based on the 2016 average gas production data. Key details of this model follow.

1. The production stage includes emissions from: well drilling, well completions and workovers, liquid unloading, well equipment leakage and venting, flare stacks, combustion and reciprocating compressors.
2. The gathering and boosting stage include emissions from: acid gas removal, dehydration, compression operations, pneumatic devices and pumps.
3. The production data is based on filtered Drilling info Desktop production data for 2016 (DrillingInfo, 2018) and the Energy Information Administration data (EIA, 2018).
4. The natural gas composition data were obtained from the USGS Energy Resources Program Geochemistry Laboratory Database (EGDB). The mean mass fractions for methane in the gas for each basin are: Green River 0.766, Permian 0.688, Piceance 0.661, San Juan 0.719 and Uintah 0.808.
5. The analysis uses EPA's GHGRP and GHGI for the 2017 reporting year to account for the venting and fugitive emissions from the natural gas supply chain, and the data for reciprocating compressor venting, reciprocating compressor exhaust, and dehydrator venting in the gathering and boosting stage are based on those reported by Vaughn *et al*. (2017).
6. The composition of vented and flared gas is calculated based on the mass composition of natural gas for each basin. Flaring is assumed to have a 98% destruction efficiency, meaning that 98% of carbon in the flared gas is converted to CO2.
7. The 100-year GWPs values used: 1 for CO2 and 36 for CH4.

Emission Factors

The total GHG emissions in g CO2-e/MJ for production, processing, and gathering, and their corresponding uncertainties were taken directly from the DOE/NETL report (Littlefield *et al.*, 2019) and are shown in Exhibit B-1. However, emissions for the San Juan Conventional & Unconventional, and San Juan CBM were taken from the WESTAR 2014 Oil and Gas emissions Inventory for Greater San Juan Basin in Colorado and New Mexico Area report (Westar, 2014). Additionally, emissions for San Juan Shale and San Juan Conventional & CBM were taken from the Future Year 2028 Emissions from Oil and Gas Activity in the Greater San Juan Basin and Permian Basin Final Report (Grant *et al.*, 2018a).

Exhibit B-1: GHG emission factors for the different basins in g CO2/MJ1 on a 100-yr GWP Time Horizon.

Basin	Production emission (g CO2-e/MJ (100-yr))[2]	Gathering Emissions plus processing (g CO2-e/MJ (100-yr))[2]	Total mean emissions (g CO2-e/MJ (100-yr))[2]	Total 95% confidence interval (P2.5)	Total 95% confidence interval (P97.5)	Total Standard error
UINTA conventional [1]	8.09E+00	8.22E+00	1.63E+01	7.81E+00	2.66E+01	4.80E+00
UINTA Tight [1]	1.87E+00	8.16E+00	1.00E+01	5.69E+00	1.50E+01	2.37E+00
GREEN RIVER Conventional [1]	1.04E+00	6.61E+00	7.65E+00	5.16E+00	1.04E+01	1.33E+00
GREEN RIVER Tight[1]	2.62E+00	6.95E+00	9.57E+00	6.25E+00	1.28E+01	1.67E+00
Piceance Tight[1]	6.98E+00	6.87E+00	1.39E+01	9.09E+00	1.98E+01	2.72E+00
San Juan Conventional[1]	1.65E+01	7.40E+00	2.39E+01	1.72E+01	3.03E+01	3.35E+00
San Juan CBM[1]	1.41E+01	7.18E+00	2.13E+01	9.15E+00	2.53E+01	4.11E+00
San Juan Conventional & unconventional[3]	1.62E+01	2.64E-01	1.64E+01			5.15E+00
San Juan CBM[3]	6.62E+00	2.64E-01	6.88E+00			2.16E+00
San Juan Shale[4]	1.82E+00	6.80E+00	8.62E+00			2.70E+00
San Juan Conventional & CBM[4]	2.58E+01	6.80E+00	3.26E+01			1.02E+01

Emission factors in units of mass of GHG per energy of content of fuel (g CO2-e/MJ) for different activities involved in the upstream stages of the life cycle were obtained from the graphs provided in the appendix of the NETL report (Littlefield *et al.*, 2019). Stages include production, gathering and boosting and processing, and activities include drilling, well completion, etc. The graphs report total CH4 and CO2 by activity for production, gathering and boosting, and processing. For the cases where it was not possible to determine the emissions from the graph, the national average value was used in a way that the total matched the total GHG emissions for each stage reported for each basin.

To estimate the emissions from completions and workovers for each basin, the total production for 2016 (Exhibit B-2) was used in combination with the CH4 emission in tons per year for the completions and workovers (Exhibit B-3 and Exhibit B-4) to calculate the emissions in g CO2-e/ MJ. All values were taken from Littlefield *et al*. (2019). The natural gas energy content used for the unit conversion was 1037 Btu per cubic feet.

Exhibit B-2: Total Production from 2016.

Basin	Production (Mcf)[2]
Permian	
Conventional	4.47E+08
Shale	1.64E+09
Green River	
Conventional	3.09E+08
Shale	9.04E+08
Uinta	
Conventional	6.71E+07
Tight	2.20E+08
San Juan	
Conventional	3.71E+08
CBM[3]	5.72E+08

Exhibit B-3: Emission factors from completions and workovers1 for Permian conventional, Permian shale, Uinta conventional and Uinta tight.

tonnes CH4/yr[2]	Permian conventional	Permian shale	Uinta conventional	Uinta tight
HF[3] completions (flaring)	4.84E+01	1.64E+02		
HF[3](workovers) (flaring)	1.28E+00	3.45E-04		
completions & workovers (No flaring)	2.47E+00	1.03E-01		
HF[3] completions (No flaring)		2.06E+01		
HF[3](workovers) (No flaring)		1.15E-02	4.99E-02	6.98E-02
completions & workovers flaring				
HF[3] completions (No flaring)				

Exhibit B-4: Emission factors from completions and workovers1 for Green River conventional, Green River tight, San Juan conventional, San Juan CMB and Piceance tight.

tonnes CH_4/yr[2]	Green River conventional	Green River tight	San Juan conventional	San Juan CBM[4]	Piceance tight
HF[3] completions (flaring)	6.56E-02	7.97E+00	1.14E-01	6.03E-03	2.32E-01
HF[3](workovers) (flaring)			3.81E-02	2.33E+01	4.23E-01
completions & workovers (No flaring)	8.42E-02	1.05E+01	3.05E+00		5.62E+00
HF[3] completions (No flaring)					
HF[3](workovers) (No flaring)					
completions & workovers flaring		5.86E+01			
HF[3] completions (No flaring)			7.92E-04	6.13E+00	

Uncertainties

The total uncertainties for the production, and gathering, boosting and processing (shown in Exhibit B-1), were taken directly from the NETL report (Littlefield *et al*., 2019), while the graphs provided in the appendix of the report were used to provide activity uncertainties. These uncertainties, expressed as 95% Confidence Interval (CI), include variability in quantity available for recovery, natural gas composition, and allocation of product (oil, gas, and natural liquids) as well as the profiles of equipment (pneumatic controllers, compression technologies, seal types, etc.) and were obtained using statistical bootstrapping. The lower and higher 95% confidence values were used to calculate the standard error (SE) as:

$$SE = \frac{(upper\ limit\ 95\%\ (P2.5) - lower\ limit\ 95\%\ (P97.5)}{3.92}$$

2. WESTAR 2014 Oil and Gas Emissions Inventory for Greater San Juan Basin in Colorado and New Mexico Area

The oil and gas emission inventories for the Greater San Juan Basin in Colorado and New Mexico Area for 2014 were developed using a combination of well count and production activity from a commercially available database of oil and gas data maintained by IHS Corporation ("the IHS database"), data from state and EPA permits, and input factors based on detailed survey or developed from the existing studies (Grant *et al*., 2018b). Key details of this inventory follow.

1. Equipment characteristics, counts, venting rates, and gas composition for the Greater San Juan Basin were developed primarily from operator surveys as described in Grant *et al*. (2018b).
2. The emission inventory treated oil wells, gas wells and CBM wells separately.
3. The approach to estimate GHGs emissions was to multiply criteria air pollutant emissions for a given activity (drilling, completions, venting, etc.) by an activity category specific GHG to criteria air pollutant emission mass ratio.

3. Emission factors from the Future Year 2028 Emissions from Oil and Gas Activity in the Greater San Juan Basin and Permian Basin Final Report

The NETL report (Littlefield *et al*., 2019) did not contain emission estimates from shale resources in the Greater San Juan Basin. Consequently, those emissions were estimated from the Future Year 2028 emissions from Oil and Gas Activity in the Greater San Juan Basin and Permian Basin Final Report (Grant *et al*., 2018a). The Greater San Juan Basin consists of Archuleta and La Plata counties in south-western Colorado and Cibola, Los Alamos, McKinley, Rio Arriba, San Juan, Sandoval, and Valencia counties in north-western New Mexico. The 2028 forecasted emissions include shale resources and are based on changes to Oil and Gas (O&G) activity metrics across all well types (shale and non-shale natural gas, shale and non-shale oil, and coalbed methane). The 2028 projections included: a decrease of 2% for active well counts, a decrease of 26% for gas production, an increase of 362% for oil production, and increase of 148% for spud count. The CH_4 emissions may be underestimated due to missing or inadequate input data. The authors did not include GHG emissions for point sources with unknown Source Classification Code (SSC). Also, the inventory does not include CH_4 emissions for nonpoint O&G sources in Colorado due to the absence of a breakdown of GHG emissions by gas in a Colorado Department of Public Health & Environment (CDPHE) emission inventory used as input. Key details from the emission estimates follow.

1. It assumes the continuation of historical declines in existing 2014 active well count, gas production and oil production.
2. It includes emission sources in addition to those included in the base year 2014 such as vehicle traffic, well site construction, and fugitive dust emission sources.
3. The O&G activity forecasts projected O&G activity changes from 2014 to 2023. O&G activity was assumed to remain constant from 2023-2028 because of high uncertainty in forecasting beyond 9 years.
4. The future spudding activity in the basin is assumed to be from the Mancos Shale.

Exhibit B-5: Historical 2014 and Projected 2028 Oil &Gas activity for the Greater San Juan Basin.

Basin	Active Well Count	Gas Production (Bcf/yr)	Oil Production (MMbbl/yr)	Spud Count
2014 Historical				
Basin-wide totals	24,870	1,060	6.1	122
2028 Projections				
Non-Shale	22,319	296	3.6	29
TRFO Shale	45	1	0	4
Southern Ute Shale	400	204	0.4	96
Mancos Shale	1,513	283	24	173
Basin-wide Totals	**24,277**	**784**	**28**	**302**

Emission Factors

The emissions factors from the 2014 inventory and the projected 2028 inventory reported in Exhibit B-1were gathered from the spreadsheets obtained by Littlefield *et al*. (2019) and Westar (2014). To provide the emission in units for mass per energy content (g CO2-e per MJ), the total production (Exhibit B-5) for each type of well, the natural gas energy content of 1037 Btu per cubic foot and a US average energy content for crude oil of 1.01E+06 Btu per cubic foot were used.

Uncertainties

The SJ Basin emission estimates are based on future projections rather than current estimates. Consequently, these estimates are more uncertain than the emission estimates from the NETL report (Littlefield *et al*., 2019). Consequently, uncertainties were estimated by multiplying the average percent SE values for all the basins in the study by 1.5.

Disclaimer

This study, based on publicly available data sources, is a technical analysis on the life cycle greenhouse gas emissions of Liquefied natural gas sourced from the U.S. Rocky Mountain Basins compared to that of coal, for use in power generation in potential world markets. Neither the authors nor the sponsors, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the completeness, accuracy, or usefulness of any information, product, apparatus, or process disclosed, or represents that its use would not infringe privately owned rights. Any reference therein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by authors or sponsors thereof. The results should not be used as the sole basis for comparative environmental claims or purchasing decisions.

Life Cycle Assessment of Greenhouse Gas Emissions from Liquefied Natural Gas Exports from North America's West Coast for Coal-Displaced Electricity Generation in Asia

Authors
Adebola S. Kasumu, PhD, P.Eng.†*
Kerry Kelly. PhD‡
Lauren P. Birgenheier, PhD‡

†A.S.K. Consulting Ltd.
‡University of Utah, Salt Lake City, Utah 84112, USA
*Corresponding Contact: askasumu@ucalgary.ca, +1 (403) 966 3715

WESTERN STATES AND TRIBAL NATIONS NATURAL GAS INITIATIVE