Draft Supplemental Environmental Impact Statement

November 2018

KALAMA SEPA
Manufacturing & Marine Export Facility

kalamamfgfacilitysepa.com

Cowlitz County Washington

Port of Kalama

Port of Kalama
110 West Marine Drive
Kalama, WA 98625

Cowlitz County, Building and Planning
207 Fourth Avenue North
Kelso, WA 98626

Dear Interested Parties, Jurisdictions, and Agencies:

The Port of Kalama (Port) and Cowlitz County (the co-lead agencies), in accordance with the Washington State Environmental Policy Act (SEPA), are releasing the draft supplemental environmental impact statement (Draft Supplemental EIS) for the proposed construction and operation of the Kalama Manufacturing and Marine Export Facility (the proposed project). The proposed project would be operated by NW Innovation Works, LLC – Kalama and would consist of a methanol manufacturing facility and a new marine terminal on the Columbia River at the Port's North Port site. The project would receive natural gas through a new 3.1-mile-long pipeline and convert the natural gas to methanol for shipment by marine vessel to global markets, primarily in Asia.

The co-lead agencies issued a Final Environmental Impact Statement (FEIS) for the proposed project on September 30, 2016. This document is a SEPA Draft Supplemental EIS to supplement the FEIS with additional analysis and consideration of mitigation for greenhouse gas (GHG) emissions attributable to the proposed project. The Draft Supplemental EIS is being prepared to address findings by the Washington State Shoreline Hearings Board in its September 15, 2017, Order on Motions for Partial Summary Judgment (SHB No. 17-010c) and the Cowlitz County Superior County Order Affirming in Part and Reversing in Part the Shorelines Hearings Board Order dated September 15, 2017 (Superior Court Case No. 17-2-01269-08).

The FEIS included quantitative analysis of on-site GHG emissions attributable to the project and included both qualitative and quantitative analysis of emissions occurring elsewhere. This Draft Supplemental EIS includes a complete quantitative analysis of emissions attributable to the proposed project on a life-cycle basis, including the following sources of GHG emissions:

- GHG emissions attributable to construction of the project;
- on-site direct GHG emissions from the project;
- GHG emissions from purchased power, including consideration of the potential sources of generation that would satisfy the new load;
- GHG emissions potentially attributable to the project from natural gas production, collection, processing, and transmission;
- GHG emissions from shipping methanol product to a representative Asian port; and
- GHG emissions associated with changes in the methanol industry and related markets that may be induced by the proposed project's methanol production.

In addition, the life-cycle analysis also addresses the GHG emissions associated the manufacture of olefins from methanol as well as the potential to use methanol as fuel.

This Draft Supplemental EIS has been prepared in accordance with SEPA (Revised Code of Washington 43.21c and Washington Administrative Code 197-11), the Port's SEPA polices, and Cowlitz County Code.

Agencies with jurisdiction and any additional agencies that commented on the FEIS will receive a copy of the Draft Supplemental EIS (on CD). Other commenters and the individuals and groups on the project mailing list maintained by the Port will receive a notice of availability of the Draft Supplemental EIS. Copies on disk may also be requested by contacting the responsible official below. The Port reserves the option of charging for the costs of this reproduction.

The co-lead agencies have determined to extend the comment period on the Draft Supplemental EIS to 45 days. Comments on the Draft Supplemental EIS will be accepted throughout the 45-day comment period, which begins November 13, 2018 and ends at 5:00 p.m. on December 28, 2018. Comments can submitted by the following methods:

Online:

https://kalamamfgfacilitysepa.com/

By Mail:

KMMEF EIS
c/o SEPA Responsible Official
Port of Kalama
110 West Marine Drive
Kalama, WA 98625

By Email:

seis@kalamamfgfacilitysepa.com

In Person:

Public Hearing
On December 13, 2018 from 6 p.m. to 9 p.m. at the Cowlitz County Event Center
1900 7th Avenue
Longview WA 98632

Questions about the FEIS may be directed to Ann Farr, Port of Kalama SEPA responsible official, at 360/673-2390 or seis@kalamamfgfacilitysepa.com.

Sincerely,

Ann Farr
SEPA Responsible Official
Port of Kalama

Elaine Placido
Director, Cowlitz County
Building and Planning Department

AF:EP:bc
Attachment

Fact Sheet

Project Name

Kalama Manufacturing and Marine Export Facility (KMMEF)

Description of Proposed Project and Alternatives

NW Innovation Works, LLC – Kalama (NWIW) and the Port of Kalama (Port) are planning to construct the KMMEF (the proposed project), which would consist of a methanol manufacturing facility and a new marine terminal on approximately 100 acres on the Columbia River at the Port's North Port site (the project site). In related actions, Northwest Pipeline LLC is proposing to construct and operate the Kalama Lateral Project (the proposed pipeline), a 3.1-mile natural gas pipeline to the proposed project, and Cowlitz County Public Utility District No. 1 is proposing to upgrade electrical service to provide power to the proposed project.

The proposed methanol manufacturing plant would convert natural gas to methanol, which would be stored on site and transported via marine vessel to global markets, primarily in Asia. The methanol is expected to be used for the production of olefins, which are the primary components in the production of consumer products, such as carpet, plastic goods, and cell phones.

The proposed marine terminal would accommodate the oceangoing vessels that would transport methanol to destination ports. It would also be designed to accommodate general use by the Port as a lay berth where vessels could moor while waiting to use other Port berths.

The alternatives evaluated in this Draft Supplemental Environmental Impact Statement (EIS) include action alternatives and a no-action alternative. The action alternatives include two methanol production technology alternatives (Technology Alternatives), and two marine terminal design alternatives (Marine Terminal Alternatives). With the No-Action Alternative, the proposed project would not be constructed.

NWIW has indicated that they will use the Ultra Low Emission (ULE) Alternative to mitigate for GHG emissions. This Draft Supplemental EIS is based on construction and operation of the ULE Alternative. The Combined Reforming (CR) Alternative is compared qualitatively to the ULE Alternative, but a detailed analysis and quantification of GHG emissions and climate change impacts associated with the CR Alternative were not completed. There are no appreciable differences in GHG emissions between the two Marine Terminal Alternatives evaluated in the final environmental impact statement (FEIS) and, thus, those terminal alternatives are not discussed in detail in the Draft Supplemental EIS.

Project Proponents

NW Innovation Works, LLC – Kalama and the Port of Kalama

Location

The proposed project would be located at the Port's North Port site at 222 West Kalama River Road in unincorporated Cowlitz County, Washington. The North Port site is located at approximately River Mile 72 along the east bank of the Columbia River. The BNSF Railway and Interstate 5 lie immediately to the east. The project site is approximately 100 acres in size and located in Sections 31 and 36, Township 7 North, Range 2 West Willamette Meridian. The proposed project would also undertake mitigation activities within parcels to the north of the project site.

Co-Lead Agencies

Port of Kalama and Cowlitz County

SEPA Responsible Officials

Ann Farr
SEPA Responsible Official
Port of Kalama
110 West Marine Drive
Kalama, WA 98625

Elaine Placido
Director, Building and Planning Department
Cowlitz County
207 Fourth Avenue North, Suite 119
Kelso, WA 98626

EIS Contact Person

Ann Farr
SEPA Responsible Official
Port of Kalama
110 West Marine Drive
Kalama, WA 98625

Phone: 360/673-2390
Website: https://kalamamfgfacilitysepa.com/
Email: SEIS@kalamamfgfacilitysepa.com

List of Permits and Approvals

Federal, state, and local permits, authorizations, or approvals required to construct and operate the proposed project are listed in the table below.

Required Permits, Authorizations, and Approvals

Permit/Authorization/Approval	Agency
Federal	
Rivers and Harbors Act Section 10/ Clean Water Act Section 404 Permit	U.S. Army Corps of Engineers (USACE)
Endangered Species Act Section 7 Consultation	National Oceanic and Atmospheric Administration (NOAA)/U.S. Fish and Wildlife Service
Marine Mammal Protection Act	NOAA Fisheries
Private Aids to Navigation Permit	U.S. Coast Guard
Section 106 of the National Historic Preservation Act	USACE
State	
Hydraulic Project Approval	Washington State Department of Fish and Wildlife
Shoreline Conditional Use Permit	Washington State Department of Ecology (Ecology)
401 Water Quality Certification	Ecology
Air Containment Discharge Permit	Southwest Clean Air Agency/Ecology
National Pollutant Discharge Elimination System (NPDES) Construction Stormwater Permit	Ecology
NPDES Industrial Stormwater General Permit	Ecology
Local	
Shoreline Substantial Development and Conditional Use Permit	County
Critical Areas Permit	County
Floodplain Permit	County
Engineering and Grading	County
Building, Mechanical, Fire, etc.	County

Authors and Principal Contributors

The Draft Supplemental EIS has been prepared under the direction of the co-lead agencies and in consultation with Cowlitz County, the City of Kalama, and other relevant agencies. The following firms were involved in the preparation of this Draft Supplemental EIS.

- BergerABAM: Draft Supplemental EIS analysis and document preparation
- Life Cycle Associates: Appendix A Greenhouse Gas Life-cycle Analysis

Date of Issue of the Draft Supplemental Environmental Impact Statement

The Draft Supplemental EIS was issued on November 13, 2018.

End of Draft Supplemental Environmental Impact Statement Comment Period

All comments on the Draft Supplemental EIS must be received on or before 5:00 p.m. on December 28, 2018.

Comments on the Draft Supplemental EIS may be submitted by the following methods:

Online:
https://kalamamfgfacilitysepa.com/

By Mail:
KMMEF EIS
C/o SEPA Responsible Official
Port of Kalama
110 West Marine Drive
Kalama, WA 98625

By Email:
SEIS@kalamamfgfacilitysepa.com

In Person:
Orally or in writing at the Public Hearing (time, date, and location follows)

Public Hearing Time, Date, and Location

December 13, 2018 from 6 p.m. to 9 p.m. at the Cowlitz County Event Center located at 1900 7th Avenue, Longview WA 98632

Projected Date of Issue of Final Supplemental Environmental Impact Statement

Comments on the Draft Supplemental EIS will be received and compiled. A Final Supplemental EIS will be published that includes responses to substantive comments received on the Draft Supplemental EIS. The Final Supplemental EIS is expected to be published in early 2019.

Agency Action and Projected Date for Action

The timing for agency decisions and actions is undetermined at this time. No agency decisions will be made until at least seven days after the issuance of the Final Supplemental EIS.

Subsequent Environmental Review

No subsequent environmental review of the proposed project is planned.

Availability of the Draft Supplemental Environmental Impact Statement

Copies of Draft Supplemental EIS and/or Notices of Availability have been distributed to agencies, tribal governments, and organizations on the Distribution List for the Final EIS.

The Draft Supplemental EIS may be viewed online and/or downloaded from the project website:

https://kalamamfgfacilitysepa.com/

Copies of the Draft Supplemental EIS are also available for review at the following locations.

Port of Kalama
110 West Marine Drive
Kalama, WA 98625

Kalama Public Library
312 North First
Kalama, WA 98625

Longview Public Library
1600 Louisiana Street
Longview, WA 98632

Kelso Public Library
351 Three Rivers Drive,
Suite 1263
Kelso, WA 98626

Cowlitz County Building and Planning
207 Fourth Avenue North
Suite 119
Kelso, WA 98626

Copies of the Draft Supplemental EIS on CD may be requested from the Port. Printed copies of the FEIS are available for a fee through the Port.

Availability of Background Materials

The Draft and Final EISs (published in March 2016 and September 2016, respectively) and all materials developed specifically for this environmental review are available on the project website:

https://kalamamfgfacilitysepa.com/

All materials incorporated by reference and supporting technical memoranda are available for review at the following location.

Port of Kalama
110 West Marine Drive
Kalama, WA 98625

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List of Acronyms/Abbreviations

BACT	best available control technology
CH4	methane
CIG	Climate Impacts Group
CO2	carbon dioxide
CO2e	CO2 equivalent
CR	combined reforming
Ecology	Washington State Department of Ecology
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency
FEIS	Final Environmental Impact Statement
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy
GWP	global warming potential
KMMEF	Kalama Manufacturing and Marine Export Facility
LCA	life-cycle analysis
LPG	liquefied petroleum gas
N_2O	nitrous oxide
NCCV	National Climate Change Viewer
NDC	nationally determined contributions
NWIW	NW Innovation Works
PIK	Potsdam Institute for Climate Impact Research
RCW	Revised Code of Washington
SCUP	Shoreline Conditional Use Permit
SWCAA	Southwest Clean Air Agency
ULE	ultra-low emissions
UNFCC	United Nations Framework Convention on Climate Change
USGCRP	U.S. Global Change Research Program
USGS	U.S. Geological Survey
WAC	Washington Administrative Code
WRI	World Resources Institute
SEPA	State Environmental Policy Act
NEPA	National Environmental Policy Act
ZLD	Zero liquid discharge
I-5	Interstate 5
Cowlitz PUD	Cowlitz County Public Utility District No. 1
RM	river mile
SHB	Washington State Shoreline Hearings Board
EIA	Energy Information Agency (Department of Energy)

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Chapter 1 Summary

1.1 Introduction

NW Innovation Works, LLC – Kalama (NWIW) and the Port of Kalama (Port) are proposing to construct the Kalama Manufacturing and Marine Export Facility (KMMEF) (proposed project) on the Columbia River at the Port's North Port site (the project site). The proposed project is required to be reviewed for impacts to the built and natural environment under the State Environmental Policy Act (SEPA) for the state of Washington. SEPA applies to decisions made by state and local agencies, including ports. The environmental review process helps state and local agencies to identify and consider possible environmental impacts that could result from government actions, including permit actions. An environmental impact statement (EIS) was completed for the proposed project in 2016. After publication of the EIS and the issuance of the Shoreline Substantial Development and Conditional Use permits, the permits were appealed to the Washington State Shorelines Hearing Board. The appeal process resulted in the need to complete supplemental review under SEPA and the completion of this Draft Supplemental EIS. This chapter provides an overview of the proposed project and the EIS review including this Draft Supplemental EIS.

1.1.1 Purpose of this Supplemental Environmental Impact Statement

This document supplements the previously prepared Final Environmental Impact Statement (FEIS) issued for the proposed project on 30 September 2016 with additional analysis and consideration of mitigation for greenhouse gas (GHG) emissions attributable to the project. The Draft Supplemental EIS addresses findings by the Washington State Shoreline Hearings Board in its 15 September 2017 Order on Motions for Partial Summary Judgment (SHB No. 17-010c) and the Cowlitz County Superior Court Order Affirming in Part and Reversing in Part the Shorelines Hearings Board Order dated 15 September 2017 (Superior Court Case No. 17-2-01269-08).

This Draft Supplemental EIS includes a life-cycle analysis covering the following sources of GHG emissions:

(1) GHG emissions attributable to construction of the project;

(2) On-site, direct GHG emissions from operations of the proposed project;

(3) GHG emissions from purchased power, including consideration of the potential sources of generation that would satisfy the new load;

(4) GHG emissions potentially attributable to the proposed project from natural gas production, collection, processing, and transmission;

(5) GHG emissions from shipping methanol to a representative Asian port; and

(6) GHG emissions associated with changes in the methanol industry and related markets that may be induced by the proposed project's methanol production.

In addition, the life-cycle analysis will also discuss the GHG emissions associated with the manufacture of olefins from methanol as well as the potential to use methanol as fuel.

The Supplemental EIS process includes the following activities:

- Completing scoping to determine areas to be addressed in the Draft Supplemental EIS
- Analyzing and reviewing the alternatives
- Identifying potential environmental impacts of the alternatives
- Identifying ways to reduce the effects of significant adverse impacts
- Publishing the Draft Supplemental EIS
- Conducting public review and commenting on the Draft Supplemental EIS
- Compiling and responding to substantive public comments received
- Releasing the Final Supplemental EIS

The Supplemental EIS process for the proposed project began with scoping the Draft Supplemental EIS. The co-lead agencies (Port of Kalama and Cowlitz County) asked members of the public, agencies, and tribes to comment on what should be analyzed in the Draft Supplemental EIS during the scoping period between 30 January 2018 and 1 March 2018. The co-lead agencies established the scope of the Draft Supplemental EIS based on state and local SEPA guidance and comments received during the scoping period. The results of this process were summarized in the scoping document issued in April 2018.

Following completion of the Supplemental EIS process, Cowlitz County will use the document to review the previously issued shoreline permits consistent with the requirements of the Superior Court Order. Cowlitz County must wait a minimum of seven days after publication of the Final Supplemental EIS to take action.

The Draft Supplemental EIS is limited to addressing GHGs and climate change as specified in the Order on Motions for Partial Summary Judgment and the Superior Court order. Analysis of impacts and mitigation associated with other elements of the environment are not the subject of the Draft Supplemental EIS and remain unchanged from those identified in the previously published FEIS. Readers are encouraged to consult the FEIS for detailed information about the proposed project.

The Port and Cowlitz County are serving as co-lead agencies for the SEPA environmental review of the proposed project. The co-lead agencies are responsible for conducting the environmental review for the proposed project and documenting it in the EIS.

An online copy of the Draft Supplemental EIS, as well as the FEIS that it supplements, is available at https://kalamamfgfacilitysepa.com. Paper copies of the document are available for review at the locations noted in section 1.6.

1.1.2 Proposed Project

The proposed project has two parts: a methanol manufacturing facility and a marine terminal. The proposed methanol manufacturing facility would convert natural gas to methanol. The methanol would be stored on site and transported by ships to destination ports, primarily in Asia. The methanol is expected to be used for the production of olefins, which are the primary components in the production of consumer products, such as medical devices, glasses, contact lenses, recreational equipment, clothing, cell phones, furniture, and many other products. The proposed marine terminal would be used primarily for loading the methanol onto ships for export. The terminal would also be available for use as a lay berth where vessels could moor while waiting to use other Port berths.

Construction of the proposed project is anticipated to begin as soon as authorizations are received (expected in 2019) and is anticipated to be completed as early as mid-2021 and as late as mid-2023. More information about the proposed project and the methanol manufacturing process is included in Chapter 2.

There are two additional projects that are related to, but not a part of, the proposed project:

- Northwest Pipeline LLC (Northwest) is proposing to construct and operate the Kalama Lateral Project (the proposed pipeline), a 3.1-mile natural gas pipeline to the proposed project. This proposed pipeline underwent a separate review through the Federal Energy Regulatory Commission (FERC). FERC completed a National Environmental Policy Act (NEPA) environmental assessment in July 2015 and FERC issued a certificate of public convenience and necessity authorizing Northwest to construct and operate the proposed pipeline on 11 April 2016. Northwest requested an extension of the certificate of public convenience and necessity to construct the proposed pipeline. FERC approved the extension through 11 April 2019 (Docket No. CP15-8-000).
- Cowlitz County Public Utility District No. 1 (Cowlitz PUD) is proposing to upgrade the existing transmission line from the existing Kalama Industrial Substation to the proposed project site, construct an on-site substation, and construct an alternative electrical supply line to the Kalama Industrial Substation to provide redundancy for electrical service. Cowlitz PUD is managing environmental reviews/permitting related to the electrical improvements.

1.1.2.1 Project Proponents

NWIW and the Port are planning to design, construct, and operate the proposed project. NWIW was formed for the purpose of developing cleaner sources for methanol production to meet global demands. More information regarding NWIW is available in Chapter 2 and at http://nwinnovationworks.com.

The Port owns the existing industrial upland site where the manufacturing facility will be located. The Port manages the state-owned aquatic lands and uplands where the marine terminal and portions of the manufacturing facility will be located. The Port is a public agency and oversees a variety of industrial uses on property along the Columbia River in the city of Kalama and unincorporated Cowlitz County. Existing Port facilities are located along the Columbia River between approximately River Mile (RM) 72 and RM 77. The Port receives revenue from leases of various Port properties, buildings, and marine terminals; services associated with the grain terminal and breakbulk docks; and the Kalama marina. More information on the Port is available in Chapter 2 and at http://portofkalama.com.

1.1.2.2 Project Location

The proposed project would be located at the Port's North Port site at 222 West Kalama River Road in unincorporated Cowlitz County, Washington (**Figure 2-1**). The North Port site is located at approximately RM 72 along the east bank of the Columbia River. The project site is bounded by the Columbia River to the west; by Tradewinds Road, the Air Liquide industrial facility, and the Port's industrial wastewater treatment plant to the east; by Port property primarily used for open space, recreation, and wetland mitigation to the north; and by the existing Steelscape manufacturing facility to the south. The Port has leased approximately 90 acres of the 100-acre North Port site to NWIW for construction and operation of the proposed methanol manufacturing facility.

1.1.3 Proposed Alternatives

The proposed project includes both the construction and operation of a methanol manufacturing facility and marine terminal. The alternatives evaluated in the EIS include action alternatives and a no-action alternative. The action alternatives include two methanol production technology alternatives (Technology Alternatives), and two marine terminal design alternatives (Marine Terminal Alternatives). With the No-Action Alternative, the proposed project would not be constructed.

NWIW has indicated that they will use ultra-low emissions (ULE) technology to mitigate for GHG emissions. This Draft Supplemental EIS is based on construction and operation of the ULE Alternative. The Combined Reformer (CR) Alternative is compared qualitatively to the ULE

Alternative, but a detailed analysis and quantification of GHG emissions and climate change impacts associated with the CR Alternative were not completed.

There are no appreciable differences in GHG emissions between the two Marine Terminal Alternatives evaluated in the FEIS and, thus, those marine terminal alternatives are not further discussed in the Draft Supplemental EIS.

Detailed descriptions of the project alternatives are included in the FEIS.

1.1.4 Project Changes

No significant changes to the proposed project have occurred since the FEIS was issued. NWIW has committed to implementing the zero liquid discharge (ZLD) method for process wastewater that was identified as a potential method in the FEIS. The shoreline permits issued for the proposed project require use of the ZLD method.

In addition, a number of minor modifications to the proposed site plan were made through the decision process for the Shoreline Substantial Development and Conditional Use permits and incorporated into the Hearing Examiner decision on those permits. These modifications include the following.

- The northwesternmost methanol storage tank was moved outside the shoreline jurisdiction.
- The proposed firefighting foam storage building will be removed and integrated into the on-site fire station.
- The proposed ship vent scrubber and containment pad are shifted east outside shoreline jurisdiction.
- Parking associated with the proposed marine terminal is shifted east and outside shoreline jurisdiction.

The Port also removed the option to use the marine terminal for ancillary activities involving topside vessel maintenance and other cargo operations (while the dock is not in active use loading methanol). In addition, the Port proposed a mitigation measure for impacts to aquatic resources consisting of a restrictive covenant on the future development of approximately 95 acres north of the proposed project site.

1.1.5 Related Actions

Two related actions (the pipeline and the electrical supply improvements) are evaluated in the EIS but are not being undertaken or permitted by the project proponents. They are evaluated in the EIS because they are being constructed primarily for natural gas and electricity supply to the proposed project. These two projects are responsible for their own separate environmental review and permitting processes, but environmental impacts from the related actions, if any, are considered in the EIS. There are no proposed changes to these two related actions since they were evaluated in the EIS and, thus, this Draft Supplemental EIS does not change the analysis contained in the EIS. These related action projects are described below.

1.1.5.1 Kalama Lateral Project

The proposed project would use natural gas as the feedstock for methanol production. Northwest is proposing to construct and operate the Kalama Lateral Project (proposed pipeline). The proposed pipeline is a 3.1-mile, 24-inch-diameter natural gas pipeline lateral extension from the existing natural gas main pipeline and related facilities that will provide natural gas service to the proposed project.

1.1.5.2 Electrical Service

Cowlitz PUD would upgrade an existing transmission line from its existing Kalama Industrial Substation (located east of the proposed project site at the northwest corner of N. Hendrickson Drive and Wilson Drive) to the project site by installing new lines on existing towers within the existing transmission line corridor to provide electrical service to the proposed project for either of the Technology Alternatives. This line originates at the substation and continues north along N. Hendrickson Drive before crossing the Kalama River and continuing north to the proposed project site. New equipment (e.g., 115-kilovolt [kV] breakers and switches) would be installed at the Kalama Industrial Substation within the existing footprint of that facility.

Cowlitz PUD will also construct a short transmission line (approximately 750 feet) between the Kalama Industrial Substation located on the west side of Interstate 5 (I-5) and an existing 115-kV transmission line on the east side of I-5 to provide redundant supply to the substation. This short line would cross I-5, the railroad, and N. Hendrickson Drive and would require installation of new poles.

1.1.6 No-Action Alternative

Under the No-Action Alternative, the proposed project would not be constructed. However, the Port would pursue future industrial or marine terminal development at this site, consistent with the Port's Comprehensive Scheme for Harbor Improvements. Until such improvements take place, the proposed project site would remain in its current state.

Given the demand for methanol in global markets, additional methanol production facilities may be constructed on another site within the Pacific Northwest or at other locations in the world, or existing production facilities could maintain production. Feedstock could consist of natural gas or other feedstock, such as coal. The market implications of not constructing the proposed project, including sourcing methanol from other production to serve the anticipated markets, are analyzed in the Draft Supplemental EIS.

1.2 Impact Assessment

This section summarizes how the construction and operation of the proposed project would likely impact GHG emissions and climate change. The 2016 FEIS addressed the following additional environmental elements, and the analysis and conclusions in the 2016 FEIS have not changed:

- Earth
- Water Resources
- Plants and Animals
- Energy and Natural Resources
- Environmental Health and Safety
- Land and Shoreline Use, Housing and Employment
- Aesthetics and Visual Resources
- Historic and Cultural Resources
- Transportation
- Public Services and Utilities
- Air Quality
- Noise

Readers should consult the FEIS for information on these elements of the environment.

The proposed project would be designed to meet local, state, and federal regulations and buildings codes. The assessment of impacts considered compliance with these standards, as well as design and other commitments by the applicant to avoid, reduce, and mitigate potential impacts.

1.2.1 Greenhouse Gas Emissions and Climate Change

The FEIS identified and compared the direct facility emissions of the CR and ULE Alternatives, including GHG emissions, from Scope 1, Scope 2, and Scope 3 emissions. For the Draft Supplemental EIS, analysis of GHG emissions for the proposed project was conducted on a life-cycle basis to quantify emissions from all aspects of the project, including direct and indirect emissions. The impact assessment used a life-cycle analysis (LCA) that accounts for all emissions that are attributable to the proposed project, including upstream and downstream emissions. The LCA also accounts for the effect of the methanol from the proposed project on the global methanol market and supply. Methanol is a global commodity and is produced around the world from different feedstocks, all with different GHG emissions rates. Because the methanol from the proposed project would create a new alternative supply of methanol, market forces will result in displacement effects on existing methanol supplies, including the effects that displaced methanol sources will have on global GHG emissions.

1.2.1.1 Proposed Project

Table 1-1 shows the annual estimated GHG emissions in terms of carbon dioxide equivalents (CO_2e) from the construction and operation of the proposed project including upstream and downstream emission sources calculated for the four scenarios analyzed: baseline, lower, upper, and market mediated. GHG emissions from construction are the same across all scenarios. Net GHG emissions from the project in consideration of all mitigation and if all displaced emissions occur would result in a reduction of global GHG emissions of between of between 9.6 and 12.6 million metric tonnes CO_2e per year.

Table 1-1. Proposed Project Average Annual Life-Cycle GHG Emissions (million metric tonnes/annum)

Scenario		Baseline	Lower	Upper	Market Mediated
Construction	Direct	0.0004	0.0004	0.004	0.004
	Upstream	0.015	0.015	0.015	0.015
Operations	Upstream Natural Gas	1.04	1.03	1.23	1.04
	Upstream Power	0.19	0.00	0.28	0.22
	Direct	0.73	0.73	0.73	0.73
	Downstream	0.20	0.20	0.36	0.20
	Subtotal	**2.17**	**1.96**	**2.62**	**2.21**
Displaced	Upstream Feedstock	1.81	1.90	0.91	1.61
	Upstream Power	0.66	0.94	0.66	0.66
	Direct	10.92	11.47	10.40	10.92
	Downstream	0.30	0.30	0.30	0.30
	Displaced Subtotal	**13.69**	**14.61**	**12.27**	**13.49**
	Net Emissions	**-11.5**	**-12.6**	**-9.6**	**-11.3**

Figure 1-1 compares the GHG emissions from upstream, direct, and downstream effects from the proposed project and those displaced by the proposed project under the baseline scenario. The size of the chart is proportional to the volume of GHG emissions or displaced GHG emissions.

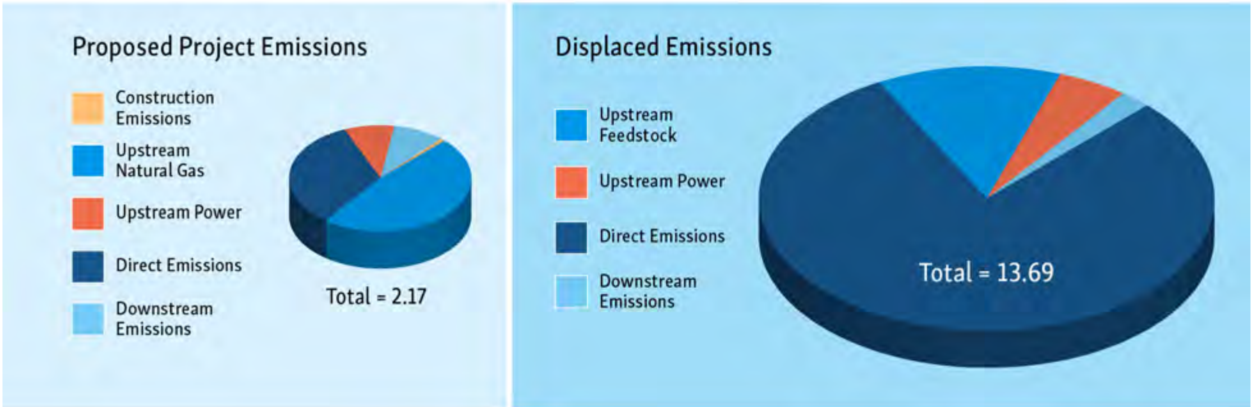


Figure 1-1. Proposed Project Emissions and Displaced Emissions by Source

1.2.1.2 Related Actions

There are no permanent sources of operational emissions for the proposed pipeline with the exception of minor fugitive methane emissions. Maintenance activity of the permanent right-of-way may result in small amounts of pollutants. Emissions from the operation of the proposed pipelines would not result in impacts to local or regional air quality, including fugitive methane emissions.

The proposed electrical service improvements would result in limited construction activities and would not introduce new permanent sources of GHG emissions.

1.3 Unavoidable Significant Adverse Impacts

The LCA demonstrates that construction of the proposed project would result in a net reduction of global GHG emissions due to expected global methanol market displacement. Additionally, implementation of mitigation proposed for the project would compensate for GHG emissions attributable to the proposed project in Washington State. Therefore, the proposed project would not result in an unavoidable significant adverse impacts to GHG emissions or climate change.

1.4 Impact Avoidance, Minimization, and Mitigation

Table 1-2 summarizes the potential impacts of the proposed project and the design features, actions, and methods that would be used to mitigate potential project impacts.

Table 1-2 Potential GHG Emissions and Climate Change Impacts and Mitigation Summary

Potential Impacts	Mitigation
Construction: • Construction (including direct, upstream and downstream GHG emissions) would results in an estimated 595,681 metric tonnes of CO_2e emissions per year total over the 3 year construction periods with approximately 40,800 metric tonnes or 7 percent of the emissions occurring in Washington. On an annual basis across the anticipated project lifetime, GHG emissions would be approximately 15,400 metric tonnes CO_2e total and 1,020 metric tonnes CO_2e in Washington. This represents approximately 0.001 percent of the annual GHG emissions in the state and 0.000031 percent of annual global GHG emissions.	**Construction:** • GHG emission reduction efforts will be employed during project construction. These may include encouraging carpooling, bicycling and other similar commuting modes, establishing no-idle policies for on-site combustion power vehicles and equipment and other similar methods. • In-state construction GHG emissions will be mitigated by the voluntary mitigation fund discussed under operations.

Potential Impacts	Mitigation
Operations: • Upstream emissions include emissions for natural gas extraction, processing, and transmission (production), as well as grid power generation. Upstream GHG emissions would result in between 1.03 million metric tonnes CO_2e and 1.51 million metric tonnes CO_2e emissions per year. This represents between 0.0021 percent and 0.0031 percent of annual global GHG emissions of 49 billion metric tonnes. Under the baseline scenario, approximately 175,200 metric tonnes CO_2e would be emitted annually in Washington, primarily from upstream power. This represents approximately 0.19 percent of the annual GHG emissions in the state. • Direct GHG emissions from the proposed project would result from the combustion of natural gas for on-site power, in boilers and other equipment and the unconverted CO_2 from the methanol production process. Direct GHG emissions are 0.73 million metric tonnes annually. All of the GHG emissions in this category would occur in Washington State and would represent an approximately 0.8 percent increase in the annual GHG emissions in the state. • Downstream emissions from the proposed project include emissions resulting from the transport of methanol to Tianjin, China would result in between 200,000 metric tonnes CO_2e and 360,000 metric tonnes CO_2e annually. This represents between 0.0004 percent and 0.0007 percent of annual global GHG emissions. A portion of these emissions would occur in Washington, and would consist of vessel and vessel support activities within the state (to approximately 3 nautical miles offshore). Under the baseline scenario, approximately 4,890 metric tonnes CO_2e would be emitted annually in Washington, primarily from fuel production and use. This represents represent approximately 0.0052 percent of the annual GHG emissions in the state. • Methanol from the proposed project would impact the market for methanol and would replace higher priced methanol from coal based sources. This displaced methanol would result in a reduction in GHG emissions of between 14.61 and 12.27 million metric tonnes CO_2e per year. • The proposed project would result in a net reduction in overall cumulative GHG emissions of between 9.6 and 12.6 million metric tonnes CO_2e per year • The CR Alternative would result in higher emissions than the ULE alternative due to higher direct emissions and higher upstream emissions due to increased natural gas use. Downstream emissions would be the same. • Under the No-Action Alternative displacement effects would not occur and GHG emissions based on methanol production would increase as demand increased and coal based methanol sources increase to meet that demand.	**Operations:** • The ULE technology will be used. This represents the lowest potential GHG emissions of the alternatives and exceeds the Best Available Control Technology for GHG emissions for methanol production. • The project will construct and use shore power for methanol transport vessels resting at berth reducing GHG emissions from this source by up to 50 percent. • NWIW will mitigate for all direct project operation GHG emissions and for upstream and downstream GHG emissions sources within Washington State through a variety of methods, including: o The purchase of verified carbon credits through carbon credit markets or banks; or o Payment of an amount comparable to carbon credit purchase amount above into a GHG mitigation fund.

1.5 Anticipated Permits and Approvals

The proposed project would require federal, state, and local permits and authorizations to construction and operate the proposed project. **Table 1-3** is a preliminary list of the permits that are anticipated to be needed for the proposed project. Additional permits and/or approvals may be identified as the environmental review process and proposed project design continue.

Table 1-3. Permits and Authorizations Required for the Proposed Project

Permit/Authorization	Agency
Federal	
Rivers & Harbors Act Section 10/ Clean Water Act Section 404	U.S. Army Corps of Engineers (USACE)
Endangered Species Act (ESA) Section 7 Consultation	National Oceanic and Atmospheric Administration (NOAA) Fisheries/U.S. Fish and Wildlife Service (USFWS)
Marine Mammal Protection Act	NOAA Fisheries
NEPA	USACE, NOAA Fisheries
Private Aids to Navigation Permit	U.S. Coast Guard
Section 106 of the National Historic Preservation Act	USACE
State	
Hydraulic Project Approval	Washington State Department of Fish and Wildlife (WDFW)
Shoreline Conditional Use Permit	Washington State Department of Ecology (Ecology)
401 Water Quality Certification	Ecology
Air Discharge Permit (based on ULE Alternative)	Southwest Clean Air Agency or Ecology
National Pollutant Discharge Elimination System (NPDES) Construction Stormwater Permit	Ecology
NPDES Industrial General Stormwater Permit	Ecology
Local	
Shoreline Substantial Development and Conditional Use Permit	County
Critical Areas Permit	County
Floodplain Permit	County
Engineering and Grading	County
Building, Mechanical, Fire, etc.	County

1.6 Draft Supplemental EIS Availability

Copies of this document are available upon request by contacting the responsible official below or online at the SEPA website maintained for the project by the co-lead agencies.

Online:

https://kalamamfgfacilitysepa.com/

By Mail:

KMMEF EIS
c/o SEPA Responsible Official
Port of Kalama
110 West Marine Drive
Kalama, WA 98625

Copies of this Draft Supplemental EIS also are available for public review at the following locations:

- Port of Kalama
  110 West Marine Drive
  Kalama, WA 98625
- Kalama Public Library
  312 North First
  Kalama, WA 98625
- Longview Public Library
  1600 Louisiana Street
  Longview, WA 98632
- Kelso Public Library
  351 Three Rivers Drive,
  Suite 1263
  Kelso, WA 98626
- Cowlitz County Building and Planning
  207 Fourth Avenue North
  Suite 119
  Kelso, WA 98626

1.7 Public Coordination

One of the primary purposes of preparing an EIS is to provide the public and agencies with information that they can use to make comments on the proposed project. After the Draft Supplemental EIS is published, copies of the document are available for public review and comment, and a public hearing is held. The hearing provides an opportunity to provide comments on the proposed project, orally and in writing.

The comment period starts on the day the Draft Supplemental EIS is published, November 13, 2018, and ends at 5:00 p.m. on December 28, 2018.

The public hearing for the DEIS will be held on December 13, 2018, from 6:00 PM to 9:00 PM at the Cowlitz County Event Center located at 1900 7th Avenue, Longview WA 98632.

To submit comments on the DEIS, visit https://kalamamfgfacilitysepa.com.

Written comments and email can be sent to:

KMMEF EIS
c/o SEPA Responsible Official
Port of Kalama
110 West Marine Drive
Kalama, WA 98625
seis@kalamamfgfacilitysepa.com

1.8 Next Steps

Comments received on the Draft Supplemental EIS during the comment period (from November 13, 2018 to 5 p.m. on December 28, 2018) will be compiled and reviewed and a Final Supplemental EIS will be prepared to address substantive comments received. The co-lead agencies anticipate that the Final Supplemental EIS will be published in late winter 2019.

Chapter 2 Proposed Project and Alternatives

2.1 Introduction

NW Innovation Works, LLC – Kalama (NWIW) and the Port of Kalama (Port) are planning to construct the Kalama Manufacturing and Marine Export Facility (KMMEF) (the proposed project), which would consist of a methanol manufacturing facility and a new marine terminal on approximately 100 acres on the Columbia River at the Port's North Port site (the project site). The location of the project site is shown on **Figure 2-1**. In a related action, Northwest Pipeline LLC (Northwest) is proposing to construct and operate the Kalama Lateral Project (the proposed pipeline), a 3.1-mile natural gas pipeline to the proposed project, and Cowlitz PUD is proposing to upgrade electrical service to provide power to the proposed project.

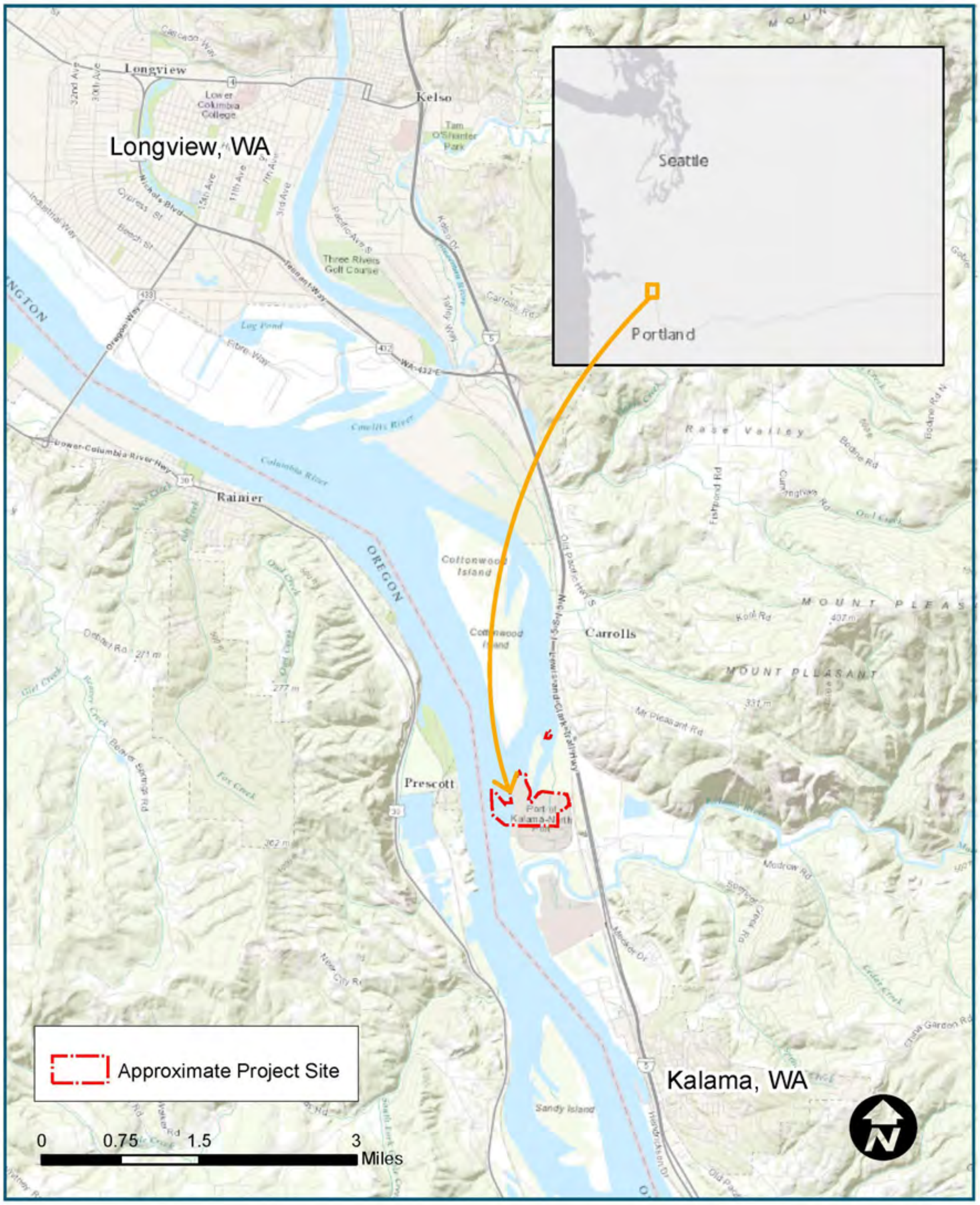
The proposed methanol manufacturing facility would convert natural gas to methanol, which would be stored on site and transported via marine vessel to global markets, primarily in Asia. The methanol is expected to be used for the production of olefins, which are the primary components in the production of consumer products, such as medical devices, glasses, contact lenses, recreational equipment, clothing, cell phones, furniture, and many other products.

The proposed marine terminal would accommodate the oceangoing vessels that would transport methanol to destination ports. It would also be designed to accommodate other vessel types and, when not in use for loading methanol, would be made available for use as a lay berth where vessels could moor while waiting to use other Port berths or for other purposes.

The proposed project is subject to environmental review under SEPA. The Port and Cowlitz County are serving as co-lead agencies for the SEPA environmental review. Federal approvals would be necessary for permits for in-water work and would be subject to environmental review under the National Environmental Policy Act (NEPA). The proposed pipeline (a related action) underwent separate review through the Federal Energy Regulatory Commission (FERC), and a NEPA environmental assessment was issued in July 2015 and was followed in April 2016 by the issuance of a Certificate of Public Convenience and Necessity authorizing Northwest to construct and operate the proposed pipeline. The proposed project would also require permits, authorizations, approvals, or other government actions from Cowlitz County, the Washington State Department of Ecology (Ecology), the Southwest Clean Air Agency (SWCAA), the Washington State Department of Fish and Wildlife (WDFW), and other agencies. These permits and the current status of any that have been issued are summarized in section 2.6.

This document is a SEPA Draft Supplemental Environmental Impact Statement (Draft Supplemental EIS) to supplement the previously prepared Final Environmental Impact Statement (FEIS) issued for the proposed project on 30 September 2016 with additional analysis and consideration of mitigation for greenhouse gas (GHG) emissions attributable to the proposed project. The Draft Supplemental EIS is being prepared to address findings by the Washington State Shoreline Hearings Board (SHB) in its 15 September 2017 Order on Motions for Partial Summary Judgment (SHB No. 17-010c) and the Cowlitz County Superior Court Order Affirming in Part and Reversing in Part the SHB Order dated 15 September 2017 (Superior Court Case No. 17-2-01269-08). This document, along with the previously prepared FEIS, is intended to meet the environmental review needs of the Port, Cowlitz County, and other state and local agencies with jurisdiction over the proposed project. The analyses in this document are also expected to be used to support NEPA review of applicable federal actions.

Detailed information on the proposed project and alternatives are contained in the FEIS and are not repeated here. Readers are encouraged to consult the FEIS.



Project Location Map
Figure 2-1

2.2 Project Site

The proposed project would be located at the Port's North Port site at 222 West Kalama River Road in unincorporated Cowlitz County, Washington (**Figure 2-1**). Existing Port facilities are located along the Columbia River between approximately River Mile (RM) 72 and RM 77. The North Port site is located at approximately RM 72 along the east bank of the Columbia River. The BNSF rail line and Interstate 5 (I-5) lie immediately to the east.

The proposed project site is located in Sections 31 and 36, Township 7 North, Range 2 West Willamette Meridian. The project site consists of portions of tax parcels 63302, 63304, 63305, 60822, 60831, 63301, and WH2500003. A portion of the proposed project site consists of state-owned lands that are subject to a Port Management Agreement between the Port and the Washington State Department of Natural Resources.

The project site is bounded by the Columbia River to the west; by Tradewinds Road, the Air Liquide industrial facility, and the Port's industrial wastewater treatment plant to the east; by Port property primarily used for open space, recreation, and wetland mitigation to the north; and by the existing Steelscape manufacturing facility to the south.

The Port is the owner of the project site and has leased approximately 90 acres of the 100-acre North Port site to NWIW for construction and operation of the proposed facility. The Port would construct the proposed marine terminal to accommodate the shipping of methanol. The Port would also improve existing access roads, construct a new access road, and develop water supply, recreation areas, and other elements to support the proposed project in the remaining 10 acres of the project site. The marine terminal would be designed to accommodate other vessel types and, when not in use for loading methanol, would be made available as a lay berth where vessels could moor while waiting to use other Port berths and for other purposes.

2.3 Project Proponent

NWIW and the Port propose to design, construct, and operate the proposed project. Collectively, NWIW and the Port are referred to as the project proponent. A brief overview of each of these entities is provided below.

2.3.1 NW Innovation Works, LLC – Kalama

NWIW is a multinational partnership formed for the purpose of developing cleaner sources for methanol production to meet global demands. The parent company of NWIW is CECC (Shanghai Bi Ke Clean Energy Technology Co., Ltd.), a technology commercialization and project development firm in the gas, synthesis gas, chemicals, and fuels industries.

2.3.2 Port of Kalama

The Port oversees a variety of industrial uses on property along the Columbia River in the city of Kalama and unincorporated Cowlitz County, including the project site. Organized in 1920 by a vote of the people as authorized under the Washington State Port District Act of 1911, the Port operates according to the provisions of Title 53 of the Revised Code of Washington (RCW) Chapter 53.04. Port districts are specifically authorized by RCW 53.04 to acquire, construct, maintain, operate, and develop harbor improvements; rail or motor vehicle transfer and terminal facilities; water transfer and terminal facilities; air transfer and terminal facilities, or any combination of such transfer and terminal facilities; other commercial transportation, transfer, handling, storage, and terminal facilities; and industrial improvements.

The Port is governed by an elected three-member Port commission and administered by an executive director. Currently, the Port employs 16 full-time and several part-time employees. The Port receives revenue from leases of various Port properties, buildings, and marine terminals; services associated with the grain terminal and breakbulk docks; and the Kalama marina. Thirty-one industries employing approximately 867 people are located at the Port.

The Port's mission is "to induce capital investment in an environmentally responsible manner to create jobs and to enhance public recreational opportunities."

2.4 Project Objectives

NWIW and the Port are pursuing the proposed project with the stated goal of reducing GHG emissions globally by producing methanol from natural gas rather than coal. Global demand for methanol for use in production of olefins is high. Global methanol demand has grown from 9 to 10 percent per year over the past 10 years. The Department of Energy's Energy Information Agency (EIA) and others project a continued growth in demand for the foreseeable future in China (Gross 2017) as well as globally (Alvarado 2016). Increased demand for methanol in Asia is being met primarily by the construction of facilities in China that manufacture methanol from coal, which emits very high levels of GHG and generates toxic byproducts and wastes (Yang et al. 2012). Producing methanol from natural gas produces substantially lower levels of GHG emissions and fewer chemical byproducts.

Producing methanol from coal in China is more expensive than producing it from natural gas in North America. Natural gas prices in the United States are lower than in China and most of the world. The cost advantages of producing methanol in Kalama from natural gas and shipping it efficiently to Asian markets, including China's coastal chemical complexes, is expected to displace methanol production from existing coal-based plants in China and should also discourage development of new coal-based methanol plants. Most of China's supply is based on coal as a feedstock. Coke oven gas is also a feedstock and a few facilities operate on natural gas.

Market forces would be expected to drive the methanol market to prefer less expensive methanol manufactured from natural gas in the United States over higher-cost methanol produced from coal.

The marine terminal is being established both for NWIW's purpose to provide the infrastructure needed to load vessels and the Port's purpose to provide for general use by the Port for its lay berth needs.

The proposed project would provide economic benefit to the region, create jobs, and improve access to recreational resources, and thus, meets the Port's mission to "induce capital investment in an environmentally responsible manner to create jobs and to enhance public recreational opportunities."

2.5 Project Alternatives

The proposed project includes both the construction and operation of a methanol manufacturing facility and marine terminal. The alternatives evaluated in the EIS include action alternatives and a no-action alternative. The action alternatives include two methanol production technology alternatives (Technology Alternatives), and two marine terminal design alternatives (Marine Terminal Alternatives). With the No-Action Alternative, the proposed project would not be constructed.

The primary differences between the Technology Alternatives are energy efficiency and energy source and the technology used for the natural gas reforming step in the methanol production process. The other primary steps in the production process remain the same in both Technology Alternatives. Both technologies are viable for use in the proposed project. Since completion of the FEIS in 2016, NWIW has selected the ultra-low emission (ULE) Alternative for its proposal.

Combined reforming (CR Alternative) is widely used in the methanol industry to perform the primary reforming of natural gas with steam. With combined reforming technology, the energy required by the reforming reaction is provided mainly by burning natural gas. Natural gas as fuel combusts through the firing burners, providing heat to allow natural gas steam reforming in the tubes of the steam methane reformer, and the flue gas is emitted to the atmosphere. The waste heat carried by hot flue gas is recovered through a series of heat exchangers to generate steam, and the steam is sent to turbines to drive rotating process equipment (such as pumps and compressors). The combined reforming technology results in lower CO2 and GHG emissions than coal-based methanol production, which relies on coal gasification to produce synthesis gas from coal feedstock. The CR Alternative has been identified by the U.S. Environmental Protection Agency as Best Available Control Technology for air emissions for a methanol project in Texas. (EPA 2013).

ULE reforming is a proven technology commonly used for reforming other chemicals from natural gas and has been used at a smaller scale for the production of methanol. With NWIW's selection of the ULE Alternative, the proposed project would be the first large-scale application of ULE technology in the world. ULE technology is designed to use process heat directly to provide energy for the reforming reaction. With ULE technology, hot synthesis gas from the secondary reformer (referred to as the autothermal reformer) flows through the shell side of the primary reformer (referred to as the GHR). Rotating process equipment are driven by electricity.

Both Technology Alternatives would require electricity and natural gas to power their processes. The CR Alternative requires more energy input and relies more heavily on natural gas for that energy. The ULE Alternative uses natural gas to power boilers, but the reforming process is powered by process heat from the autothermal reformer. The ULE Alternative requires substantially more electricity because electricity is used to power compressors and pumps. Cowlitz PUD does not currently have adequate transmission capacity to supply all the electricity needs of the ULE Alternative. Therefore, the ULE Alternative requires an on-site, natural gas-fired power generator to provide a portion of the power. Provision of natural gas and electrical service to the project site will be conducted by others but because they would not be constructed but for the project, the impacts of them are included in this EIS.

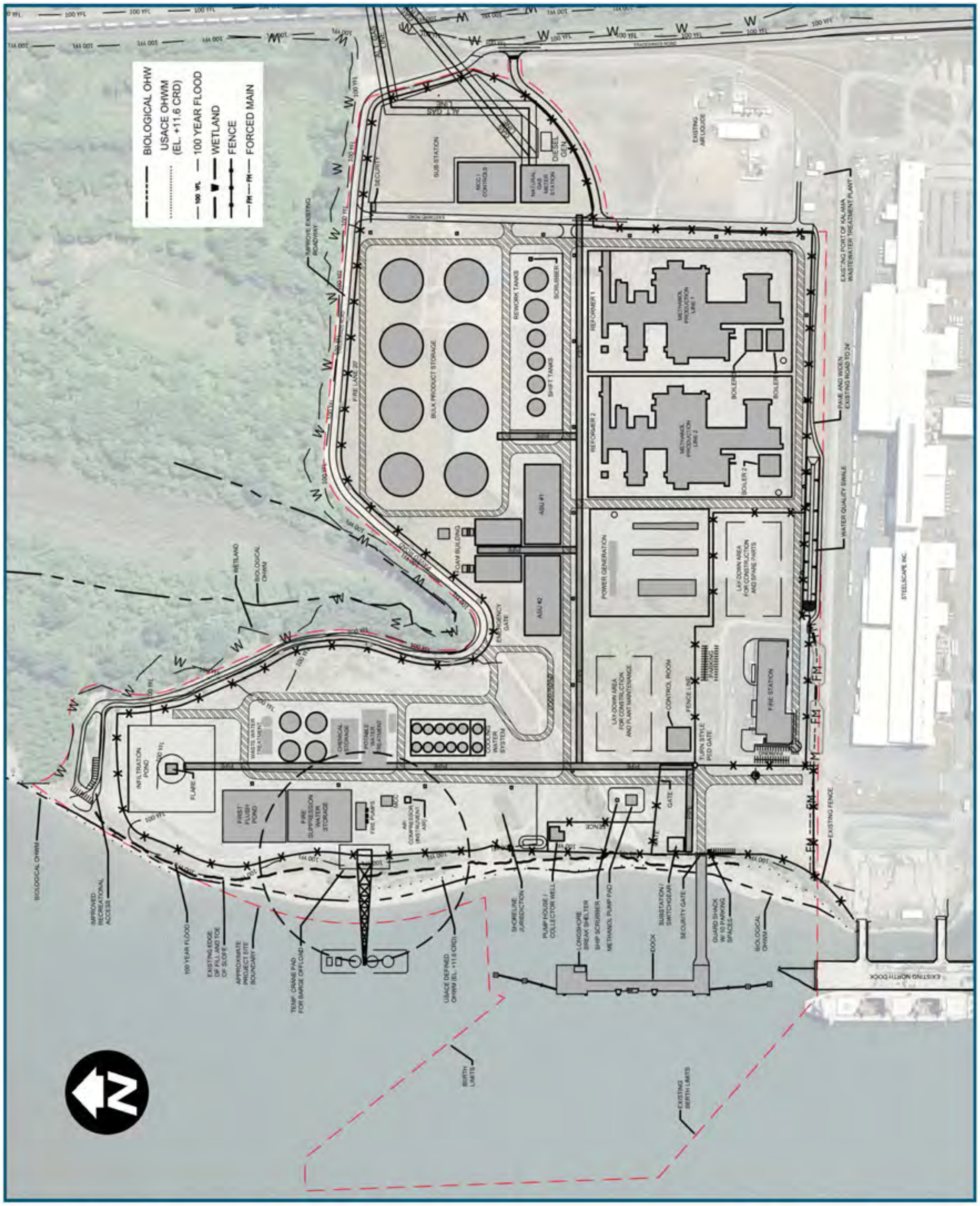
The DEIS and FEIS completed in 2016 evaluated both the CR and ULE alternatives. NWIW has indicated that they intend to use the ULE technology in the development of the proposed project and this Draft Supplemental EIS is based on the construction and operation of the ULE Alternative. The CR Alternative is compared qualitatively to the ULE Alternative, but a detailed analysis and quantification of GHG emissions and climate change impacts associated with the CR Alternative were not completed.

There are no appreciable differences in GHG emissions between the two Marine Terminal Alternatives evaluated in the FEIS and, thus, those marine terminal alternatives are not further discussed in the Draft Supplemental EIS.

A No-Action Alternative is analyzed in this EIS, as required by SEPA regulations. Under the No Action Alternative, the proposed project would not be constructed on the project site. Given the project site's highway, rail, and waterfront access and the Port's Comprehensive Scheme for Harbor Improvements, absent the proposed project, the Port would be expected to pursue future industrial or marine terminal development of the site. Given the demand for methanol in global markets, additional methanol production facilities may be constructed on another site in the Pacific Northwest or at other locations in the world, or existing production facilities could maintain production. Feedstock could consist of natural gas or another feedstock, such as coal.

2.5.1 Project Changes

Since publication of the FEIS, minor changes to the project have occurred from actions of the proponent and from the permitting process. These project changes were incorporated into the shoreline permits previously issued by the County and Ecology. The project changes are summarized in this section.



ULE Alternative Site Plan
Figure 2-2

KALAMA SEPA
Manufacturing & Marine Export Facility

2.5.1.1 Site Plan Changes

A number of minor modifications to the proposed site plan were made through the decision process for the Shoreline Substantial Development and Conditional Use permits (NWIW 2017). These modifications include the following.

- The northwesternmost methanol storage tank was moved so that it is located entirely outside shoreline jurisdiction.
- The proposed firefighting foam storage building will be removed and integrated into the on-site fire station.
- The proposed ship vent scrubber and containment pad are shifted east outside the shoreline jurisdiction.
- Parking associated with the proposed marine terminal is shifted east and outside the shoreline jurisdiction.

The Port also removed the potential to use the marine terminal for ancillary activities involving topside vessel maintenance and other cargo operations (while the dock is not in active use loading methanol).

2.5.1.2 Wastewater Treatment and Disposal

In the FEIS, two methods of wastewater disposal for wastewater generated during the methanol production process were considered. Under both methods process wastewater would be treated prior to discharge. Under the surface water discharge method wastewater would be directed to the existing outfall serving the adjacent steel facility and the Port's industrial wastewater treatment plant for discharge to the Columbia River. Under the zero liquid discharge (ZLD) system, the wastewater would be directed to an evaporator and a crystallizer to reduce the process wastewater to a solid salt cake suitable for landfill disposal and high-quality distillate for reuse in the methanol facility. NWIW has committed to use of the ZLD system and it is a condition of approval of the shoreline permit issued for the proposed project.

2.5.1.3 Mitigation Actions

The Port proposed an additional mitigation measure for impacts to aquatic resources consisting of placement of a restrictive covenant on the future development of approximately 95 acres north of the proposed project site.

2.6 Anticipated Permit Requirements

2.6.1 Proposed Project

The proposed project would require federal, state, and local permits and authorizations. **Table 2-1** below is a list and current status of the permits that are anticipated to be required. Additional permits or approvals may be identified as the design and environmental review processes proceed. Permit that have been applied for will be obtained prior to and closer to actual construction.

Table 2-1. Permits and Authorizations Required for the Proposed Project

Agency	Permit/Authorization	Status
Federal		
USACE	Rivers & Harbors Act Section 10/ Clean Water Act Section 404	Under review (Permit No. NWP-2014-177/2)
National Oceanic and Atmospheric Administration (NOAA)	Marine Mammal Protection Act Incidental Harassment Authorization	Issued: 10/19/2018

Agency	Permit/Authorization	Status
NOAA Fisheries/USFWS	Endangered Species Act Section 7 Consultation	NOAA Biological Opinion issued 10/10/2017 (Reference No. WCR-2015-3594) USFWS Biological opinion issued 11/14/2016 (Reference No. 01EWFW00-2016-F-0065 and 0066)
USACE, NOAA	NEPA	USACE – Pending NOAA – Environmental Assessment issued 10/2016 Finding of No Significant Impact issued 10/24/2016
U.S. Coast Guard	Private Aids to Navigation Permit	Not applied for
USACE	Consultation under Section 106 of the National Historic Preservation Act if the project would affect historic properties	Will be addressed in Section 10/404 permit review
State		
WDFW	Hydraulic Project Approval	Issued 10/16/2106 (Permit No. 2016-5-150+01)
Ecology	Shoreline Conditional Use Permit	Approved 6/8/2017[1] (CUP No. 1056)
Ecology	401 Water Quality Certification	Issued: 2/15/2017 (Order No. 13925; USACE # NWP-2014-177/2)
SWCAA	Air Discharge Permit	Issued: 6/7/2017 (Permit No. ADP 16-3204)
Ecology	NPDES Construction Stormwater Permit	Not applied for
Ecology	NPDES Industrial General Stormwater Permit	Not applied for
Local		
County	Shoreline Substantial Development Permit	Issued (Permit# SL 16-0975)[1]
	Critical Areas	Issued: 4/5/2017 (Permit # 16-07-3712)
	Floodplain Permit	Issued: 4/5/2017 (Permit # 16-07-3712)
	Engineering and Grading	Not applied for
	Building, Mechanical, Fire, etc.	Not applied for

[1] The Shorelines Hearings Board invalidated this permit (SHB No. 17-010c). The invalidation was reversed by the Superior Court (Superior Court Case No. 17-2-01269-08) and the shoreline substantial development permit is subject to review by the County after completion of the Supplemental EIS process.

2.6.2 Related Actions

Table 2-2 lists the permits, approvals, and consultation anticipated to be required for the construction and operation of the proposed pipeline. **Table 2-3** lists the permits anticipated to be needed for the construction and operation of the proposed transmission line improvements.

Table 2-2. Permits and Authorizations Required for the Proposed Pipeline

Agency	Permit/Approval	Status
Federal		
FERC	Certificate of Public Convenience and Necessity	Approved, extended (Docket No. CP15-8-000)
USACE	Permit for the discharge of dredge or fill material into waters of the United States under Section 404 of the Clean Water Act	Under review (Permit # NWP-2014-177/2[2]
USFWS	Consultations for impacts on federally listed threatened and endangered species and critical habitat under Section 7 of the ESA and the Migratory Bird Treaty Act	USFWS Biological opinion issued 11/14/2016 (Reference #01EWFW00-2016-F-0065 and 0066)
NOAA Fisheries	Consultations for impacts on federally listed threatened and endangered species and critical habitat under Section 7 of the ESA and the Magnuson-Stevens Act	N/A (USACE determined and NOAA concurred that the project would have no effect on listed species)
Advisory Council on Historic Preservation	Consultation under Section 106 of the National Historic Preservation Act if the project would affect historic properties	Addressed through Certificate of Public Convenience and Necessity
State		
Ecology	401 Water Quality Certificate	Issued 6/7/2017 (Order #14096)
Ecology	General Permit for Construction Stormwater Discharge under the NPDES	Under Review
WDFW	Hydraulic Project Approval	Issued: 2/10/2017
Washington State Department of Natural Resources	Forest Practices Act	Not applied for
Washington State Department of Transportation (WSDOT)	Road Crossing Permit	Under Review
Local		
Cowlitz County	Critical Areas Ordinance, Pipeline Ordinance, Grading Ordinance, County Road Crossing Permits	Critical Areas Issued: 2/01/2017 Remaining: Under Review
City of Kalama	Fill and Grade, Critical Areas, Right-of-Way Permits	Under Review
Other		
BNSF	Landowner agreement for installation located in the right-of-way	Under Review

[2] The USACE is reviewing the proposed project and the pipeline project under a single permit process.

Table 2-3. Permits and Authorizations Required for the Proposed Electrical Service

Agency	Permit/Approval	Status
Other		
BNSF	Wire Line Crossing License	Not applied for
State		
WSDOT	Utility Permit	Not applied for

2.7 Benefits or Disadvantages of Reserving Project Approval for a Later Date

If the Port, County, or other agency with permitting authority were to delay action on the proposed project, the impacts associated with construction and operation of the facility would be delayed along with any potential benefits of the project, such as increased tax revenues and job creation. In addition, if the proposed project were to be delayed, the market for methanol and products created from it could respond by developing additional methanol plants in other locations. These plants may manufacture methanol from coal or by using a less efficient technology. Delaying the action could allow the Port to pursue other development opportunities on the site that could result in similar, lesser, or more adverse impacts than the project.

2.8 References

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U.S. Environmental Protection Agency (EPA). 2013 Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions, Celanese Clear Lake Plant, Pasadena, TX (EPA Region 6; December 12, 2013).

Yang, Chi-Jen, and Robert B. Jackson. 2012. China’s Growing Methanol Economy and Its Implications for Energy and the Environment, Energy Policy (Elsevier 2012). http://people.duke.edu/~cy42/Methanol.pdf.

Chapter 3 Greenhouse Gas Emissions and Climate Change

3.1 Introduction

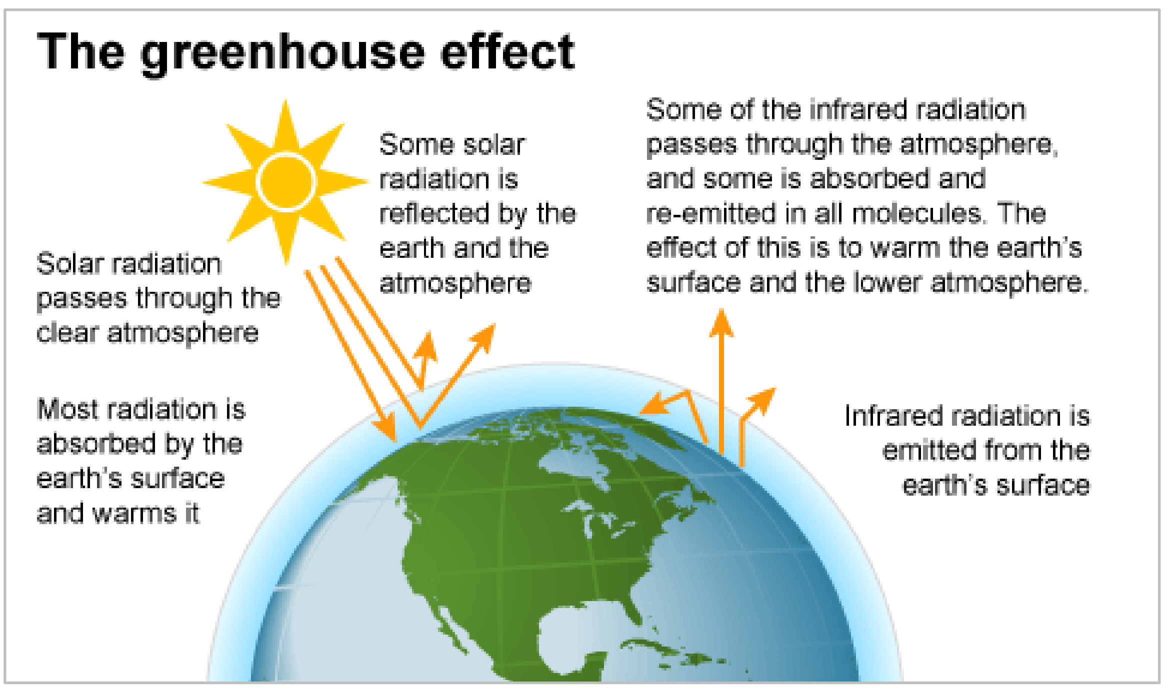
This chapter assesses the potential impacts of construction and operation of the proposed project, the No-Action Alternative, and related actions on greenhouse gas (GHG) emissions and climate change. This chapter principally supplements the information regarding GHG and climate change in Chapter 4, Air Quality and Greenhouse Gas Emissions, and cumulative impacts included in section 15.5.2 of the Kalama Manufacturing and Marine Export Facility (KMMEF) Final Environmental Impact Statement (FEIS). This supplement does not address effects of climate change on the project or project site as these were previously addressed in the FEIS and are not modified by the supplemental information on GHG emissions and the contribution of those emissions on climate change. Most of the material and findings in this chapter are summarized from the *Kalama Manufacturing and Marine Export Facility Supplemental GHG Analysis* (Appendix A).

3.2 Affected Environment

This section describes the existing conditions related to GHG emissions and climate change and the existing regulatory environment.

3.2.1 The Greenhouse Effect

The greenhouse effect is a natural process that results in warmer temperatures on the surface of the earth than the temperatures that would occur without the process. The effect is due to concentrations of certain gases in the atmosphere that trap heat as infrared radiation from the earth is reradiated back to outer space (**Figure 3-1**). The greenhouse effect is essential to the survival of most life on earth − it keeps some of the sun's warmth from reflecting back into space and sustains temperatures that make the earth livable (Myhre et al. 2013).



Source U.S. Energy Information Administration

Figure 3-1. Greenhouse Effect

3.2.2 Greenhouse Gases and Climate Change

The phenomena of natural and human-caused effects on the atmosphere that cause changes in long-term meteorological patterns due to global warming and other factors are generally referred to as climate change. Because of the importance of the greenhouse effect and related atmospheric warming to climate change, the gases emitted globally that affect such warming are called GHGs. Primary GHGs include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and other trace gases. Natural sources of GHGs include biological and geological sources, such as plant and animal respiration, forest fires, and volcanoes. However, anthropogenic sources of GHGs are the primary concern for climate change because of the volume they represent. The GHGs of primary importance are CO_2, CH_4, and N_2O because they represent most of the GHGs emitted by industry. Because CO_2 is the most abundant of these gases, GHGs are usually quantified in terms of CO_2 equivalent (CO_2e), based on their relative longevity in the atmosphere and their related global warming potential (GWP).

The global climate changes continuously, as evidenced by repeated episodes of warming and cooling documented in the geologic record. However, the rate of change has typically been incremental, with warming or cooling trends occurring over the course of thousands of years. The past 10,000 years have been marked by a period of incremental warming, as glaciers have steadily retreated across the globe. However, scientists have observed an unprecedented increase in the rate of warming over the past 150 years. This recent warming has coincided with the Industrial Revolution, which resulted in widespread deforestation to accommodate development and agriculture along with increasing use of fossil fuels. These changes in land uses and consumption of carbon-laden fuels have resulted in the release of substantial quantities of GHGs – to the extent that atmospheric concentrations have reached levels unprecedented in the modern geologic record.

The accumulation of GHGs in the atmosphere affects the earth's temperature. While research has shown that the earth's climate has natural warming and cooling cycles, the overwhelming amount of evidence indicates that emissions related to human activities have elevated the concentration of GHGs in the atmosphere far beyond the level of naturally occurring concentrations and that this in turn is resulting in more heat being held within the atmosphere. The Intergovernmental Panel on Climate Change (IPCC) has concluded that it is “very likely“ – representing a probability of greater than 90 percent – that human activities and fossil fuels, commonly referred to as anthropogenic emissions, explain most of the warming over the past 50 years (IPCC 2007), and that cumulative emissions of CO_2 over time are the driver of global temperature change (IPCC 2014).

The IPCC Fifth Assessment Report (IPCC 2014) suggests global emission reduction targets needed to limit warming by the end of the century for different scenarios, with:

- A 40 to 70 percent reduction below 2010 global levels by 2050 is likely to limit warming below 3.6 degrees Fahrenheit (2 degrees Celsius).
- A 70 to 95 percent reduction below 2010 global levels is more likely than not to limit warming below 2.7 degrees Fahrenheit (1.5 degrees Celsius).

The IPCC predicts that under current human GHG emission trends, the following climate change effects could be realized within the next 100 years (IPCC 2014).

- Global temperature increases between 3.1 to 8.6 degrees Fahrenheit (1.7 to 4.8 degrees Celsius).
- Potential sea level rise between 10 to 32 inches (0.26 to 0.82 meter).
- Increase in ocean acidification.
- Reduction in snow cover and sea ice.
- Potential for more intense and frequent heat waves, tropical cycles, and heavy precipitation.
- Impacts to biodiversity, drinking water, and food supplies.

Recently, the IPCC released a new report that evaluates the impacts of global warming of 2.7 degrees Fahrenheit (1.5 degrees Celsius) above preindustrial levels. The report concludes that warming to this extent will likely be seen earlier than previously anticipated and result in associated impacts occurring earlier as well (IPCC 2018).

The Climate Impacts Group (CIG) is a Washington State-based interdisciplinary research group that collaborates with federal, state, local, tribal, private agencies, organizations, and businesses, and studies impacts of natural climate variability and global climate change on the Pacific Northwest. CIG research and modeling indicates the following possible impacts of human-based climate change in the Pacific Northwest (CIG University of Washington, 2013).

- Increased temperatures.
- Changes in water resources, such as decreased snowpack; earlier snowmelt; decreased water for irrigation, fish, and summertime hydropower production; increased conflicts over water; and increased urban demand for water.
- Changes in salmon migration and reproduction.
- Changes in forest growth and species diversity and increases in forest fires.
- Changes along coasts, such as increased coastal erosion and beach loss due to rising sea levels, increased landslides due to increased winter rainfall, permanent inundation in some areas, and increased coastal flooding due to sea level rise and increased winter stream flow.
- Resulting health impacts.

The Climate Science Special Report developed by the U.S. Global Change Research Program (USGCRP) is designed to be an authoritative assessment of the science of climate change, with a focus on the United States. It represents the first of two volumes of the Fourth National Climate Assessment, mandated by the Global Change Research Act of 1990. It predicts a similar set of impacts including the following (Mote et al. 2014):

- Increase in average annual temperatures of 3.3 degrees to 9.7 degrees Fahrenheit.
- Change in average annual precipitation from a reduction of 10 percent to an increase of 18 percent with all models showing a decrease in summer precipitation by up to 30 percent.
- Low stream flows west of the Cascades.
- Increased wildfires, insect outbreaks, and diseases leading to widespread tree die-off.
- Continued sea level rise.

The U.S. Geological Survey (USGS) National Climate Change Viewer (NCCV) (USGS 2014) contains historical and future climate projections at county levels for the United States. The viewer includes historical (1950 to 2005) and future (2006 to 2099) climate projections for Representative Concentration Pathways GHG emission scenarios developed for the Fifth Assessment Report of the IPCC. The NCCV indicates that in Cowlitz County minimum temperatures are likely to rise by 3.8 to 4.3 degrees Fahrenheit (2.1 to 2.4 degrees Celsius) and maximum temperatures by 4 to 5.4 degrees Fahrenheit (2.2 to 3.0 degrees Celsius) by 2040. Precipitation changes reported in the NCCV show both increases and decreases in precipitation.

CO_2, CH_4, and N_2O are considered well-mixed GHGs that are circulated and mixed around the globe affecting climate change in the same manner irrespective of the location of the emission source. (USGCRP 2017). Thus GHG missions originating from Cowlitz County have the same effects as those from any other location and vice versa. While the consensus is that anthropogenic GHG emissions are a cause of climate change, it is the cumulative effect of past and present emissions in the atmosphere rather than individual sources that is the cause (USGCRP 2017). It is also not generally possible to equate a specific climate change response to a specific emissions source from an individual project (U.S. Forest Service 2009, Environmental Protection Agency [EPA] 2009, California Air Pollution Control Officers Association 2008, Council on Environmental Quality 2016, U.S. Fish and Wildlife Service 2008, IPCC 2007, NMFS 2017).

3.2.3 Existing Conditions

This section describes the current anthropogenic GHG emissions data across various geographies to provide context for the evaluation of the proposed project-related impacts. As indicated above, climate change results from GHG emissions on a global basis; therefore, the most relevant data to provide are those related to global GHG emissions. However, because Washington State and United States policies and/or regulations address GHG emissions at the state and federal levels, these geographies are included.

3.2.3.1 Global

There is no definitive source of data that quantifies total GHG emissions on a global basis, but there are a number of sources that estimate emissions, including the IPCC, the World Resources Institute (WRI), and the Potsdam Institute for Climate Impact Research (PIK).

The IPCC Fifth Synthesis Report (IPCC 2014), the most recent synthesis report from IPCC, estimated global emissions in 2010 as 49 billion metric tonnes of CO_2e. The Climate Access Indicators Tool[3] database maintained by WRI estimates 2014 global GHG emissions of 49 billion metric tonnes of CO_2e (Climate Watch 2018), and the PIK estimates 50 billion metric tonnes for the same period. While there are differences between the reports, the three sources are consistent and show a continuous growth in GHG emissions over time. Figure 3-2 summarizes global GHG emissions in CO_2e by sector as reported by the IPCC.

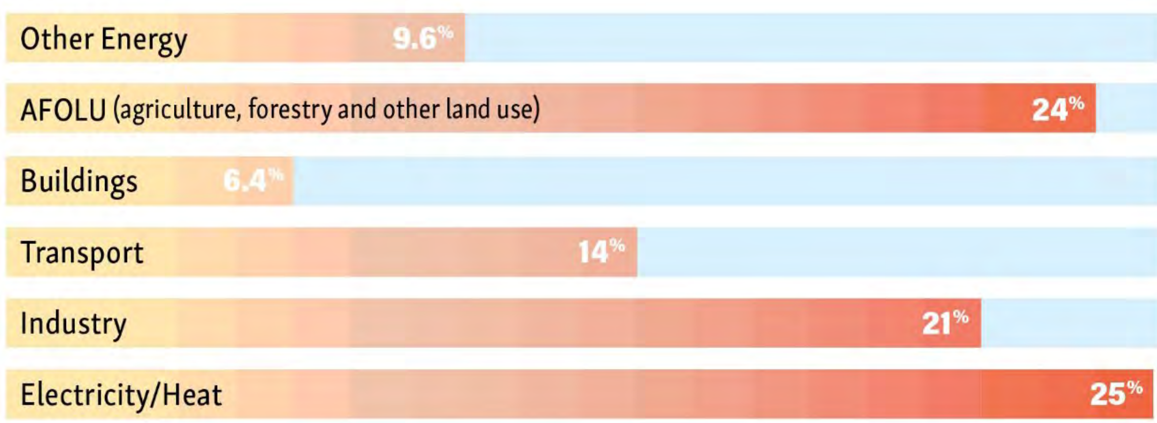


Figure 3-2. Global GHG Emissions by Sector

3.2.3.2 National

EPA publishes the *Inventory of U.S. Greenhouse Gas Emissions and Sinks,* which is the official U.S. inventory of GHG emissions to comply with the United Nations Framework Convention on Climate Change. The most recent published report (2018) includes data up to and including 2016. Estimated 2016 GHG emissions are 6,511,300,000 metric tonnes of CO_2e[4] (EPA 2018). **Figure 3-3** shows U.S. GHG emissions by sector in 2016. By far the largest sources of GHG emissions in the U.S. is from the combustion of fossil fuels representing 86 percent of net GHG emissions. The bulk of those emissions are from electric power generation and transport (representing approximately 36 percent each).

[3] Available at https://www.climatewatchdata.org/ghg-emissions?breakBy=sector&source=33&version=2.

[4] Net emissions for the same period were calculated as 5,794,500,000 metric tonnes when considering GHG emission sinks from Land Use, Land Use Change, and Forestry.

Figure 3-3. 2016 U.S. GHG Emissions by Sector

Since 1990, U.S. GHG emissions have increased at an average annual rate of 0.1 percent resulting in a total increase of 2.4 percent from 1990 to 2016. However, U.S. GHG emissions peaked in 2007 at 7,351,000,000 metric tonnes and have been on a downward trend primarily because of reductions from the electricity sector. GHG emissions from the electricity sector have declined by 36 percent since 2008 from the reduction in coal-based power and increased use of natural gas and renewables, while GHG emissions from transportation have increased by nearly 22 percent since 1990 (EPA 2018). A 1.9 percent decrease occurred from 2015 to 2016, primarily from the substitution of coal with natural gas and other non-fossil fuel energy sources for electric power generation and warmer winter conditions (EPA 2018). **Figure 3-4** shows total U.S. GHG emissions from 1990 to 2016 in million metric tonnes CO_2e.

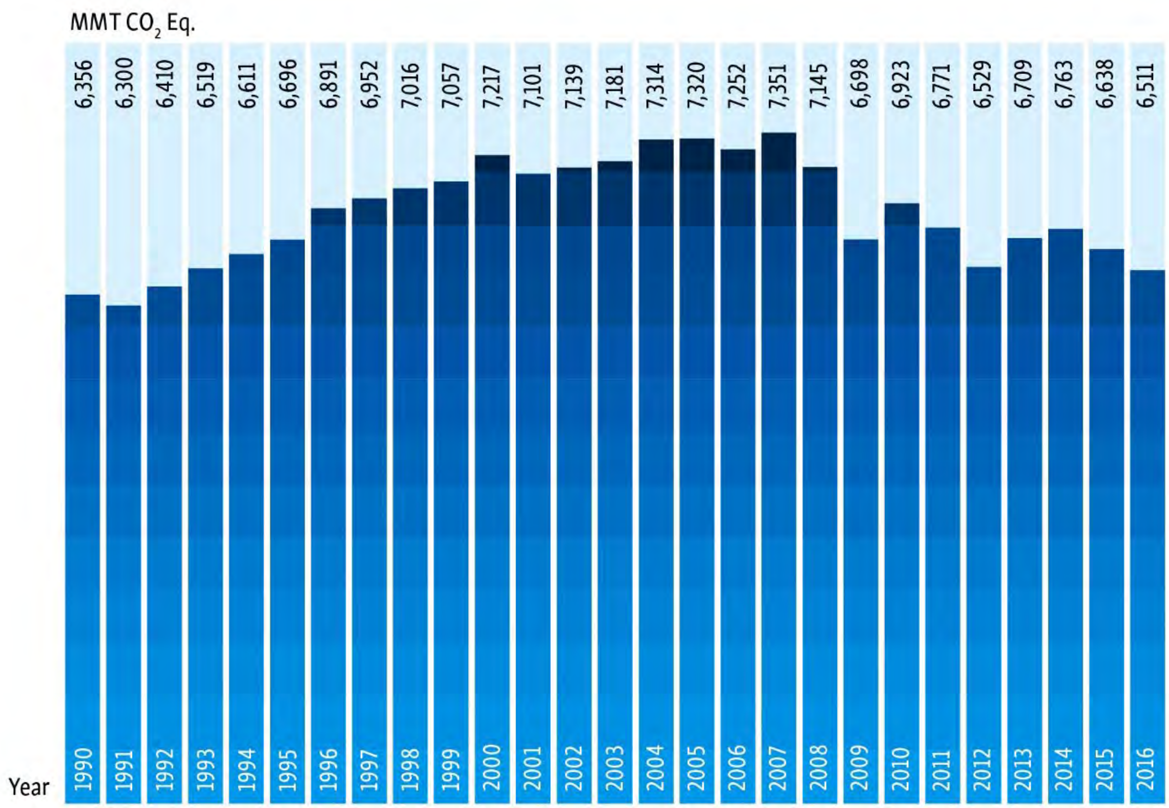


Figure 3-4. U.S. GHG Emissions 1990 - 2016

3.2.3.3 State

The Washington State Department of Ecology (Ecology) published the most recent (20136) statewide GHG emissions in the *Report to the Legislature on Washington Greenhouse Gas Emissions Inventory: 2010–2013*. Total GHG emissions in Washington are reported as 94,400,000 metric tonnes CO_2e in 2013. Ecology categorized GHG emissions (Ecology 2016a) into the following sectors:

- Transportation
- Electricity consumption (electricity generation/demand)
- Residential, commercial, and industrial (fuel combustion from space and/or process heating)
- Fossil fuel industry (leaks or venting from processing or distribution of fossil fuels
- Waste management
- Industrial processes (non-combustion sources)
- Agriculture

Figure 3-5 shows statewide emissions by sector from 1990 to 2013 and the forecasted emission from 2013 to 2020 from Ecology based on the business-as-usual case. The largest category of emissions is transportation with industrial processes making up only a small percentage. Washington's emission profile is unique in the relative small percentage of GHG emissions from electricity reflecting the volume of hydropower generated in the state (Ecology 2016d).

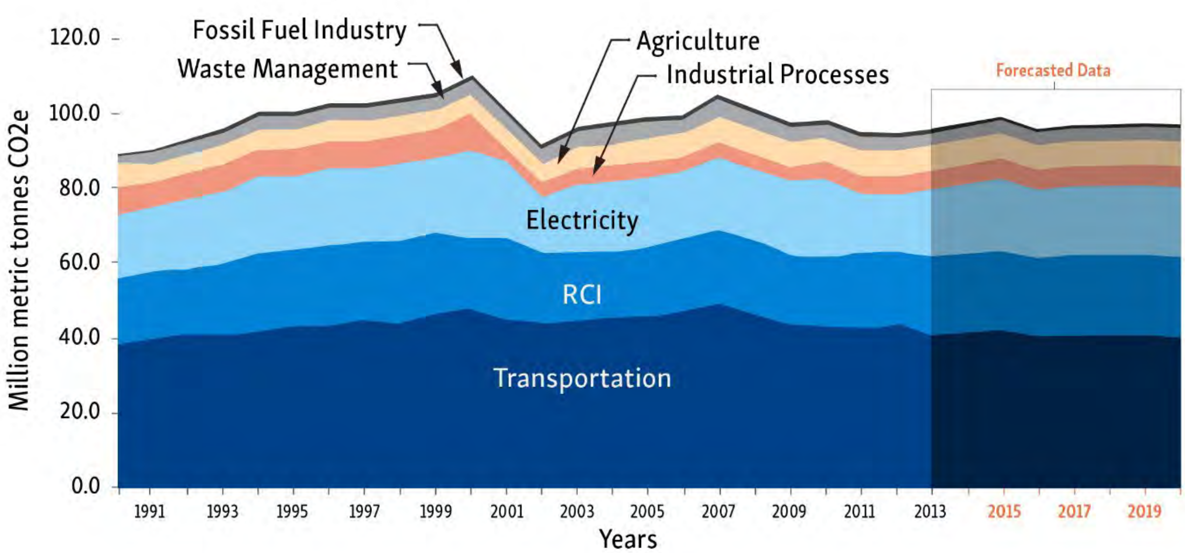


Figure 3-5. Washington State GHG Emissions by Sector 1990 to 2013 with Forecast to 2020

The state's total GHG emissions in 2013 were 6,000,000 metric tonnes higher than the 1990 baseline. The state's GHG emissions declined by about 2.8 percent from 2010 to 2013. This includes an increase of approximately 0.8 percent from 2012 to 2013 primarily due to the reduction in hydropower from low water availability and replacement with natural gas and coal based generation (Ecology 2016a).

As a percentage of total U.S. GHG emissions, Washington represents approximately 1.4 percent of the total 2013 GHG emissions of 6.7 billion metric tonnes[5] estimated by the EPA (EPA 2018) and shown in **Figure 3.6**. Washington's per capita emission are also considerably lower than the U.S. average (Ecology 2012).

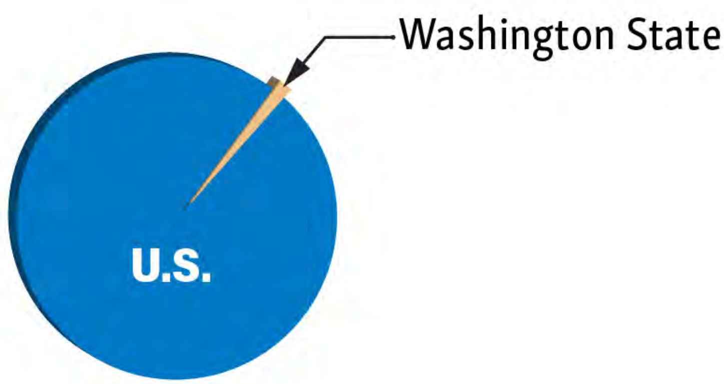


Figure 3-6. Washington GHG Emissions as Percentage of U.S. GHG Emissions in 2013

Individual sources of GHG emissions in Washington that generate over 10,000 metric tonnes of GHGs per year are required to report emissions to the state pursuant to Revised Code of Washington (RCW) Chapter 70.94. In 2013, 293 facilities reported emissions, which accounted for approximately 36 million metric tonnes or 38 percent of the estimated statewide GHG emissions.[6] The reported emissions in 2016 fell to approximately 32 million metric tonnes (Ecology 2016b) or a decline of approximately 11 percent. **Table 3-1** shows the 15 largest reported emitters in Washington for 2016, the most recent reporting year. These are direct operation emissions and do not represent an LCA accounting of all emissions as is being conducted here. For example, the GHG emissions reported for the TransAlta facility do not include emissions associated with the mining and delivery of coal to the power plant.

Table 3-1. Top 15 Individual GHG Emission Sources in Washington (2016)

Facility	County	Sector	Emissions (tonnes CO_2e)
TransAlta Centralia Generation LLC, Centralia	Lewis	Power Plants	5,094,331
BP Cherry Point Refinery, Blaine	Whatcom	Refineries	2,418,086
Shell Puget Sound Refinery, Anacortes	Skagit	Refineries	1,980,471
Longview Fibre Paper and Packaging, Inc./KapStone Kraft, Longview	Cowlitz	Pulp and Paper	1,662,744
Nippon Dynawave, Longview	Cowlitz	Pulp and Paper	1,560,766
Tesoro Refining & Marketing Company LLC, Anacortes	Skagit	Refineries	1,350,774
Alcoa Intalco Works, Ferndale	Whatcom	Metals	1,261,364
Grays Harbor Energy Center, Elma	Grays Harbor	Power Plants	1,081,729
WestRock CP LLC, Tacoma	Pierce	Pulp and Paper	1,034,608
Cosmo Specialty Fibers Inc., Cosmopolis	Grays Harbor	Pulp and Paper	989,316

[5] 2013 data used instead of more recent U.S. data in order to provide a comparison with the most up to date Washington data (2013).

[6] The complete inventory of reported emissions is available from Ecology at: https://ecology.wa.gov/Air-Climate/Climate-change/Carbon-reduction-targets/Facility-greenhouse-gas-reports

Facility	County	Sector	Emissions (tonnes CO_2e)
Kettle Falls Generating Station, Kettle Falls	Stevens	Power Plants	912,128
Boise Paper, Wallula	Walla Walla	Pulp and Paper	804,657
Phillips 66 Ferndale Refinery, Ferndale	Whatcom	Refineries	767,043
Georgia-Pacific Consumer Products LLC, Camas	Clark	Pulp and Paper	599,199
PacifiCorp Energy, Chehalis Generating Facility, Chehalis	Lewis	Power Plants	591,615

Source: Ecology 2016b

3.2.3.4 Local

No emission inventories are known to be available that quantify GHG emissions generated in Cowlitz County specifically.

3.3 Regulatory Setting

This section consists of summaries of governmental laws, regulations, policies, and agreements that address GHG emissions.

3.3.1 International

Various international agreements have been established to address GHG emissions and climate change. This section does not provide an exhaustive summary of those agreements and includes only the most current and relevant.

3.3.1.1 Paris Agreement

The Paris Agreement is an international agreement intended to combat climate change by reducing emissions. In total, 197 parties (countries) agreed to the convention and 180 parties have ratified the agreement. The Paris Agreement aims to keep global temperature rise in this century to well below 2 degrees Celsius beyond pre-industrial levels and strengthens the ability of countries to deal with the impacts of climate change (United Nations Framework Convention on Climate Change [UNFCC] 2018a).

In 2016, the United States joined the Paris Agreement. A key element of the agreement is nationally determined contributions (NDCs). They are an aspirational statement of efforts by each country to reduce its national emissions and adapt to the impacts of climate change consistent with the agreement. The NDC submitted by the United States is intended to achieve a reduction by 2025 of the level of its total GHG emissions by 26 to 28 percent below their 2005 level and to make best efforts to reduce its emissions by 28 percent (UNFCC 2018b). In August 2017, the United States stated its intent to withdraw from the Paris Agreement as soon as the country is eligible to do so (2020) (White House 2017). The United States continues to participate in negotiating the specific actions that will be taken by parties to the agreement and thus, until officially withdrawn is actively involved in activities supporting the Paris Agreement (United Nations 2017).

The Governor of Washington State, Jay Inslee, joined other governors from certain U.S. states to form the U.S. Climate Alliance. The alliance has committed to meet their share of the Paris Agreement GHG emissions target by 2025 (U.S. Climate Alliance 2018).

3.3.2 Federal

3.3.2.1 Clean Air Act

The Clean Air Act of 1963 is the comprehensive federal law regulating emissions from both mobile and stationary sources of air pollution. In 2007, the U.S. Supreme Court ruled that GHGs were considered air pollutants under the Act.

EPA rules require that certain emitters subject to Prevention of Significant Deterioration regulations and Title V Operation Permit Programs (40 CFR Chapter 1 Part 52) employ best available control technology (BACT) for GHG emissions. These provisions apply to large sources of emissions and GHGs alone do not trigger the requirement to obtain permits under these authorities. The proposed project is not subject to a Prevention of Significant Deterioration or Title V permit.

In response to the fiscal year 2008 Consolidated Appropriations Act (H.R. 2764; Public Law 110-161), the EPA issued "Mandatory Greenhouse Gas Reporting" the greenhouse gas reporting rule (40 CFR 23 Part 98) that requires reporting of GHG data and other relevant information by large sources and suppliers in the United States. The rule generally applies to certain activities that emit 25,000 metric tonnes of CO_2e or more per year. The rule requires only reporting and does not limit or require the reduction of emissions. The proposed project would be required to report direct project emissions under this program.

The EPA proposed the Affordable Clean Energy rule in August 2018; it would have established emission guidelines for states to develop plans to address GHG emissions from existing coal-fired power plants. The rule would replace the 2015 Clean Power Plan, which the EPA has proposed to repeal because it exceeded EPA's authority. The U.S. Supreme Court stayed the Clean Power Plan and it has never gone into effect. The plan would have established limits on CO_2 for new fossil-fuel-fired power plants. Currently, there is no requirement to reduce or mitigate for GHG emissions from coal-fired power plants. The Clean Power Plan and the Affordable Clean Energy rule would not apply to the proposed project.

3.3.3 State

3.3.3.1 Limiting Greenhouse Gas Emissions (RCW 70.235)

RCW Chapter 70.235, Limiting Greenhouse Gas Emissions, established GHG reduction goals compared to a 1990 baseline and directed Ecology and other state agencies to undertake specific tasks related to GHG emissions. The intent of the chapter, as specified in RCW 70.235.005(3), was to:

(a) Limit and reduce emissions of GHGs as stated in RCW 70.235.020;
(b) minimize the potential to export pollution, jobs, and economic opportunities; and
(c) reduce emissions at the lowest cost.

The statute does not specify regulatory requirements to reduce or limit GHG emissions that are applicable to individual projects (including the proposed project), industries, or sectors. RCW 70.235.050 does impose requirements for state agencies to develop plans to reduce their GHG emission to meet the adopted reduction targets. The statewide reduction goals of RCW 70.235.020 are:

- By 2020, reduce overall emissions to 1990 levels;
- By 2035, reduce overall emissions to 25 percent below 1990 levels;
- By 2050, reduce overall emissions to 50 percent below 1990 levels, or 70 percent below the state's expected emissions that year.

The most recent statewide GHG emission inventory (Ecology 2016a) indicated that the state's total GHG emissions in 2013 were 94.4 million metric tonnes CO2e, which is 6 million metric tonnes CO2e higher than the 1990 baseline. To achieve the goal by 2020, a reduction of more than 6 percent is required from 2013 levels.

3.3.3.2 Washington Clean Air Act (RCW 70.94)

The Washington Clean Air Act (RCW 70.94) establishes rules for reporting GHG emissions for sources that exceed 10,000 tonnes CO_2e emissions per year. Washington Administrative Code (WAC) 173-441 establishes the reporting rules. No specific reduction or mitigation requirements are included except that CO_2 mitigation for certain fossil-fueled electric generation facilities is required consistent with the calculations in RCW 80.70 discussed below. The proposed project would be required to report emissions under this rule, but mitigation for CO_2 emissions would not apply to the project.

3.3.3.3 Vehicle Miles Traveled Reduction Goals (RCW 47.01.440)

RCW 47.01.440 requires the Washington State Department of Transportation to take steps to reduce per capita vehicle miles traveled. As measured from a baseline of 75 billion miles, the reduction goals are 18 percent by 2020, 30 percent by 2035, and 50 percent by 2050.

3.3.3.4 Carbon Dioxide Mitigation (RCW 80.70)

RCW 80.70 requires fossil-fueled electric generation facilities over 25,000 kilowatts to offset a portion of their CO_2 emissions. Offsets can include payment to a third party to provide mitigation, the direct purchase of permanent carbon credits, or investment in applicant-controlled carbon dioxide mitigation projects, including combined heat and power (cogeneration). The payment is currently $1.60 per ton of CO_2 and applies to only 20 percent of total emissions. RCW 80.70 would not apply to the proposed project.

3.3.3.5 Greenhouse Gas Emissions—Baseload Electric Generation Performance Standards (RCW 80.80)

RCW 80.80 establishes a maximum GHG emission rate of 1,010 pounds for each kilowatt hour produced for certain baseload power generation facilities. RCW 80.80 would not apply to the project because it is not a baseload facility, but the on-site power generation would meet the standard.

3.3.3.6 Clean Air Rule (WAC 173-442)

Ecology adopted the Clean Air Rule in 2016; it established specific GHG emission standards for certain stationary sources, petroleum product producers, and importers and natural gas distributors. The Clean Air Rule generally applies to emission sources emitting over 100,000 metric tonnes per year of CO_2e. Ecology estimates that the Clean Air Rule, would reduce emissions by over 16 million tons of CO_2e per year by 2035 (Ecology 2016c). The proposed project would have been subject to this rule and would have been required to reduce emissions over time or obtain emission reductions from other parties, projects, or cap and trade programs. Subsequent to its adoption, the rule was held to be invalid by the Thurston County Superior Court and the Clean Air Rule is not currently being enforced.[7]

[7] While the Clean Air Rule is not currently being enforced the Shoreline Conditional Use Permit issued by Ecology for the proposed project included a condition of approval which requires the proposed project to comply with requirements similar to the Clean Air Rule.

3.3.3.7 Washington Carbon Pollution Reduction and Clean Energy Action (Executive Order 14-04)

This executive order from Governor Jay Inslee established a task force to provide recommendations to the legislature for design and implementation of carbon emission limits. The report submitted to the Governor in November 2014[8] included four main findings surrounding emission limits and market mechanisms:

- Emissions-based or price-based market mechanisms add unique features to an overall carbon emissions reduction policy framework.
- Thoughtful and informed policy design, drawing on the lessons learned from other jurisdictions, task force member perspectives, and additional analysis, will be required to achieve either an emissions-based or price-based policy approach that is workable for the state of Washington.
- Reaching the state's statutory carbon emissions limits will require a harmonized, comprehensive policy approach.
- Certain important questions remain unanswered and further analysis will be important to provide the foundation for a well-informed and well-functioning policy approach.

3.3.3.8 Washington's Leadership on Climate Change (Executive Order 09-05)

This executive order from then-Governor Christine Gregoire was established after the adoption of RCW 70.235 and ordered the state to continue to participate in the Western Climate Initiative,[9] estimate emissions, quantify emission reductions, and identify strategies and actions that could be used to meet the 2020 target for emission reductions adopted by RCW 70.235 in 2008, as well as other directives to Ecology and the Washington State Department of Transportation for specific emissions reduction efforts.

3.3.3.9 Executive Order 07-02

Governor Christine Gregoire established this executive order, which articulated statewide GHG reduction goals that are consistent with those subsequently established as law by RCW 70.235.020. The order also included directives to reduce GHGs, including increasing vehicular emission standards, retrofitting diesel vehicles, energy efficient buildings, and other similar activities.

3.3.3.10 Proposed Ballot Initiative 1631

This pending ballot measure would require certain large emitters (with exceptions) to pay $15 initially and increasing over time for every ton of CO_2 they release into the atmosphere. If the measure passes and becomes law, the requirement may or may not be applicable to the project.

3.3.3.11 Southwest Clean Air Agency

The Southwest Clean Air Agency (SWCAA) is responsible for enforcing delegated federal and state air quality standards and regulations in Cowlitz County. SWCAA has no laws or regulations that address GHGs other than the aforementioned Title V permit requirements from the Clean Air Act.[10]

[8] Available at: https://www.governor.wa.gov/sites/default/files/documents/CERT_Final_Report.pdf

[9] Washington is not currently an active participant in the program (see http://www.wci-inc.org/program-design.php)

[10] While SWCCA does not have specific standards limiting GHG emissions, NWIW proposed an emission limit within its application, and the Air Discharge Permit issued for the project includes a GHG emission limit.

3.3.4 Local

3.3.4.1 Cowlitz County

Cowlitz County is required by RCW 36.70.320 to develop and adopt a comprehensive plan to guide the orderly physical development of the County. The plan is intended to guide the policy decisions related to the physical, social, and economic growth of the County and provide a framework for future growth and development, including development in shoreline areas. The County recently updated its comprehensive plan in 2017 and the plan does not contain any specific policy direction regarding GHG emissions or climate change. In addition, the County recently updated its Shoreline Master Program (including receiving approval by Ecology) and it also does not include provisions related to GHG emissions or climate change. Current county code and other policy documents do not contain specific policy or regulatory requirements related to GHG emissions and/or climate change. The county does have specific regulations regarding the protection of critical areas including wetlands and shoreline areas.

3.4 Methodology

3.4.1 Introduction

Section 4.4.1.2 of the FEIS identified and compared the direct facility emissions of the combined reformer (CR) and ultra-low emission (ULE), alternatives including GHG emissions from Scope 1 (equivalent to Operation Emissions –Direct identified in Section 3.5.5), Scope 2 (equivalent to the upstream power category identified in Section 3.5.4) and Scope 3 (equivalent to the downstream transportation category in Section 3.5.6) activities. Scope 1 emissions were calculated as 31.3 percent higher for the CR Alternative than the ULE Alternative. Including Scope 1, 2 and 3 GHG emissions in the analysis results in the CR Alternative having 11 percent higher GHG emissions than the ULE Alternative. The ULE Alternative was selected by the project proponent, NW Innovation Works, LLC – Kalama (NWIW), to mitigate GHG emissions by reducing those resulting from the proposed project.

For the Draft Supplemental EIS, analysis of GHG emissions for the proposed project was conducted on a life-cycle basis to quantify emissions from all aspects of the project. First, the analysis looks at a LCA for GHG emissions for the proposed facility based on the ULE Alternative. The LCA looks at all emissions that are created by the proposed project, including upstream and downstream emissions. Secondly, the analysis looks at the effect of the methanol from the proposed project on the global methanol market and supply. Methanol is a global commodity and is produced around the world from different feedstocks, all with different GHG emissions rates. Because the methanol from the proposed project would create a new alternative supply of methanol, market forces will result in displacement effects on existing methanol supplies. The second part of this analysis looks at the effects that displaced methanol sources will have on global GHG emissions. Appendix A provides detailed descriptions of the methods summarized in this section.

Because the effect of GHG emissions occur over a long duration, the life cycle and total global emissions are considered the relevant metric. LCA is a technique used to model the environmental impacts associated with the production of a good. LCAs are typically computed by taking a full inventory of all the inputs and outputs involved in a product's life cycle. In the case of methanol production, the LCA approach covers the full life cycle from resource extraction and transportation, methanol manufacturing, and the transportation of methanol to China, where it is used produce olefins.

An LCA looks at all aspects of a product's production from the acquisition of raw materials to the delivery of the finished good or product, such as methanol. For simplicity, an LCA is composed of three primary inputs (upstream, facility, and downstream) that are summed to establish the total life of GHG emissions for the KMMEF. The primary parameters for this LCA are defined in **Table 3-2. Figure 3-7** represents the upstream, facility, and downstream inputs.

Table 3-2. Life Cycle Inputs

Life-Cycle Step	Description of Inputs
Construction	Construction equipment, dredging, materials of construction Fuel and power production
Upstream Input	Natural gas feedstock extraction, processing and transmission (including fugitive GHG emissions), purchased electric power production
KMMEF Facility	Boiler, natural gas power plant, and methanol facility operations
Downstream Input	Methanol transport olefin production

The LCA also considers the upstream emissions from fuel production in the various life cycle steps. Thus, emissions resulting from fuel production is included in each step based on the amount of fuel used. For example, the construction phase includes GHG emissions from the combustion of fossil fuels in construction equipment and the upstream GHG emission from extraction, refining, and transportation of those fuels.

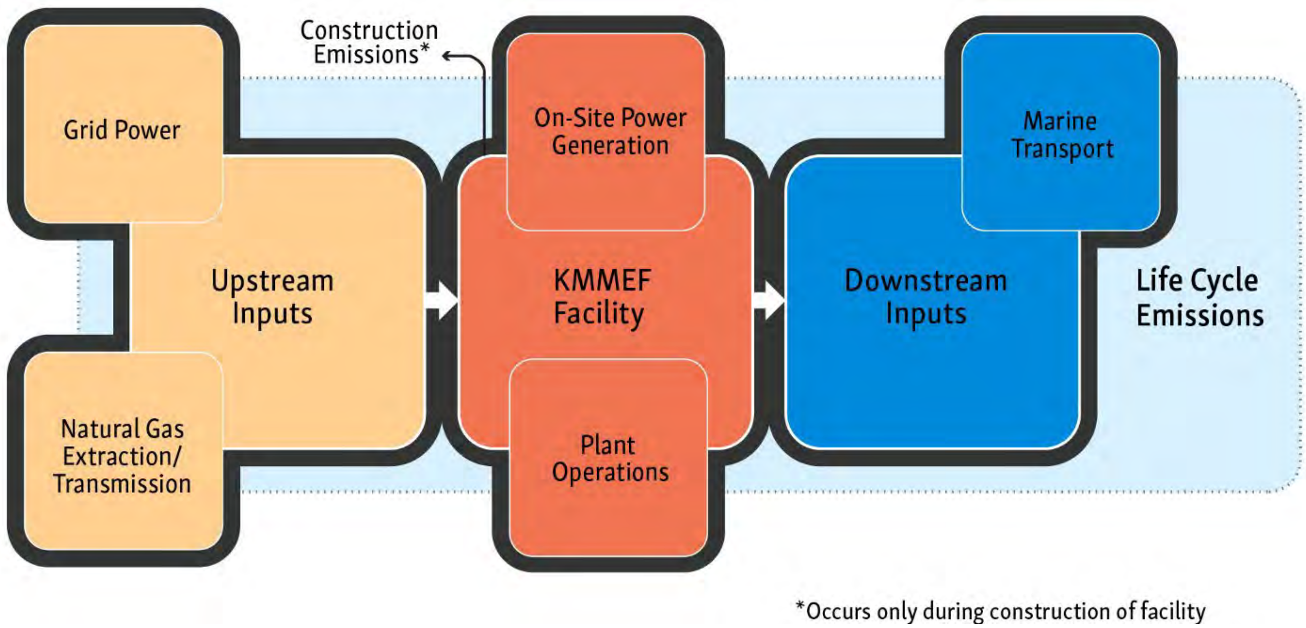


Figure 3-7. LCA Inputs

The product life cycle does not necessarily refer to the length of time that a particular facility operates, rather it represents the process for creating a good. In this case, the LCA uses the operation of the proposed project for one year as the metric for evaluating GHG emissions. The one-year calculation is appropriate because this is how most GHG emissions are calculated in state and national inventories and, therefore, it provides context for the GHG emissions from the proposed project. The proposed project has a production capacity of 10,000 tonnes of methanol per day and will produce 3.6 million metric tonnes per year. NWIW has indicated that the plan will have a life span of approximately 40 years. This time period is used primarily to account for construction emissions on a yearly basis.

GWP is a measure of the potential of a gas to have an effect that could lead to climate change due to prolonged residence time in the atmosphere. The GWP can be used to quantify and communicate the relative and absolute contributions to climate change of emissions of different GHGs (Myhre et al. 2013) and emissions from countries or sources. The UNFCC uses the 100-year GWP. The United States and the Washington Greenhouse Gas Reporting program (WAC 173-441) also primarily use the 100-year GWP for reporting GHG emissions. Values for the proposed project are based on the 100-year GWP for consistency with international, United States, and Washington reporting requirements.

The 20-year GWP is sometimes used as an alternative to the 100-year GWP. The 20-year GWP prioritizes gases with shorter lifetimes, because it does not consider impacts that happen more than 20 years after the emissions occur. Because all GWPs are calculated relative to CO_2, emission calculations based on a 20-year GWP will be larger for gases with lifetimes shorter than that of CO_2 and smaller for gases with lifetimes longer than CO_2 (EPA 2014). GHG emissions from the proposed project consist primarily of CO_2, a GHG with a long lifetime, and thus, it is appropriate to use the 100-year GWP (see Appendix A for greater detail). In addition, a sensitivity analysis was completed using the 20-year GWP to show the differences in the use of the two different GWP values.

3.4.2 Life-cycle Models

The LCA uses the publicly available Greenhouse Gases, Regulated Emissions, and Energy in Transportation (GREET) and GHGenius models. These models are widely used in Canada and the United States for LCA and provide the ability to modify parameters on a project-specific basis. Even though GREET and GHGenius were developed for transportation, they provide the same level of or greater detail as other LCA models, and the models and documentation are available to the public. The GREET and GHGenius models were selected to provide the basis for upstream life-cycle emissions used in this analysis.

The GREET model is a standard in performing life-cycle analyses of transportation fuels. GREET was developed by U.S. Department of Energy's Argonne National Laboratory (2009) to calculate life-cycle emissions from direct and upstream sources of transportation fuels. GREET is a downloadable spreadsheet model that includes customizable macros for project-specific customizations. The model has been extensively used to quantify life-cycle emissions associated with fuels and other products. This study uses the GREET framework to calculate emission rates for the upstream inputs in the KMMEF project.

GHGenius is a spreadsheet-based model developed by Natural Resources Canada, an agency of the Canadian government, to calculate emissions associated with traditional and alternative fuels production. GHGenius is used to model emissions associated with natural resource extraction because the primary sources of natural gas for the proposed project are assumed to be Canadian. GHGenius includes regionalized factors for western Canada that are appropriate for this analysis.

3.4.3 Model Inputs

This LCA analysis includes emissions from upstream, facility, and downstream inputs to calculate the total life-cycle GHG emissions from the proposed project.

3.4.3.1 Upstream

Upstream GHG emissions includes those associated with natural gas extraction, processing and transport to the proposed project site, and off-site (or purchased) power generation.

3.4.3.1.1 Natural Gas Extraction, Processing and Transmission

Natural gas produced in Canada is assumed to be the primary feedstock for the proposed project and would be transmitted through the existing Northwest Pipeline interstate pipeline system to the location of the proposed pipeline lateral that will deliver natural gas to the proposed project site. The delivery of natural gas to the project may change only the distance or direction of flow in the system and is not expected to effect a change in energy use for compressor operations for the pipeline. Natural gas extraction rates and pipeline volumes are not expected to change regardless of the proposed project.

Natural gas extraction involves the operation of compressors and separation equipment at the wellhead and gas processing facilities. **Figure 3-8** shows the upstream emissions pathways for natural gas. GHG emissions are calculated based on the energy inputs from aggregate data, which are inputs to the GHGenius and GREET models. The models calculate the life-cycle emissions, including the upstream emissions, to produce fuels for gas extraction and processing. The GREET model also calculates energy inputs and emissions from compressors used for natural gas transport and includes provisions for fugitive methane emissions at all stages of the extraction and transportation processes.

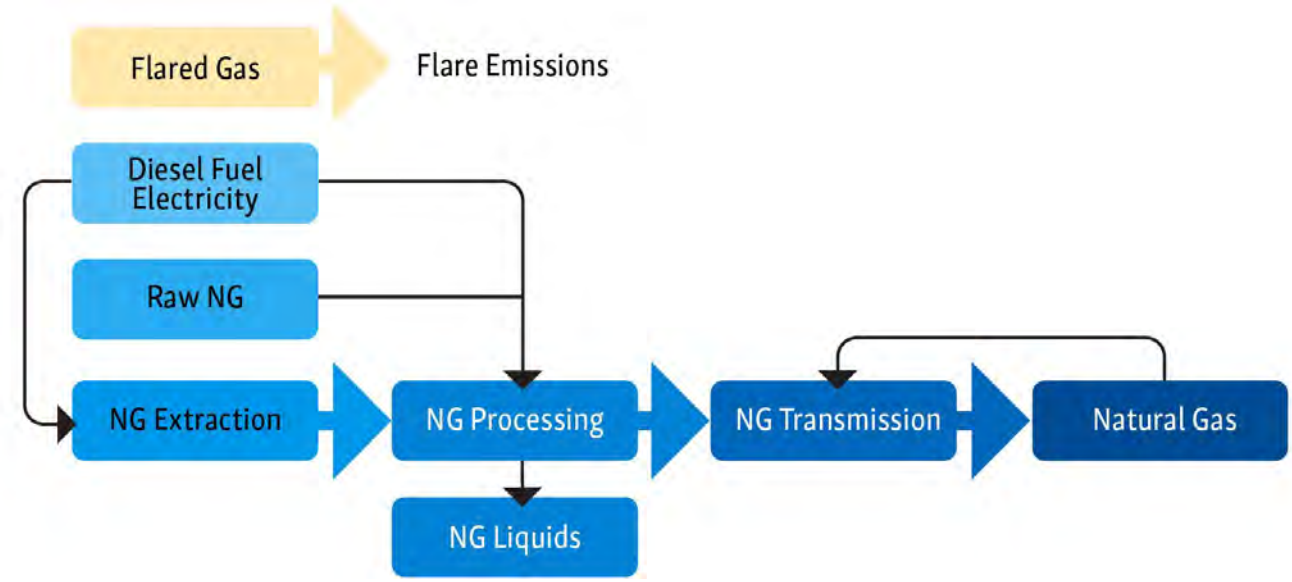


Figure 3-8. Natural Gas Extraction and Transmission Components

3.4.3.1.2 Power Generation

Electrical power is a common component to all inputs in the LCA. Electricity is used at all phases to operate machinery and equipment, compressors, and transmission facilities. Power is provided by the established electrical grid and comes from many sources. Emissions from power generation include emissions for natural gas turbines and boilers and coal boilers as well as upstream inputs for fossil fuels and uranium for nuclear power plants. **Figure 3-9** shows the various inputs for power generation. The inputs for power generation to the GREET model are the resource mix with GREET model inputs. Power generation efficiency and transmission loss are also GREET inputs, but they are not modified for this analysis.

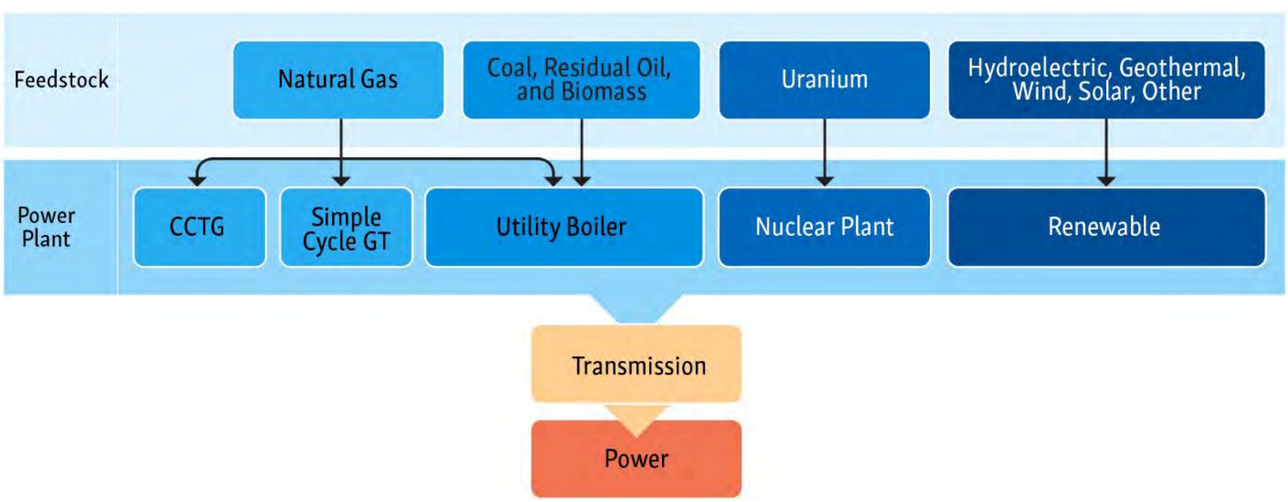


Figure 3-9. Power Generation Components

3.4.3.2 Direct Facility Inputs

GHG emissions produced by the facility itself include emissions associated with the construction and operation of the facility, including GHG emissions from combustion of natural gas for on-site power generation, combustion of diesel in generators and other similar equipment, the methanol production process, and fugitive emissions from various equipment.

3.4.3.2.1 Construction Emissions

Construction activities consist of the development of the proposed project, including the construction of the methanol facility, storage tanks, the power plant, the marine terminal, and dredging at the site. Construction activities include the operation of earth-moving equipment, cranes, trucks, pile drivers, compressors, pumps, and other equipment. Employee commute traffic, material transport, degrading of dredged material and the production of materials used to construct the proposed project also generate GHG emissions and are included in the calculation of GHG emissions. The GREET model incorporates standard emission factors and rates for construction equipment and vehicles. GHG emissions occur prior to operations but, for accounting purposes to determine the average annual emissions, are divided across the anticipated 40-year operational life of the proposed project.

3.4.3.2.2 Facility Operations

Direct operating GHG emissions from the proposed project include the sources shown in **Figure 3-10**. Natural gas is converted to methanol with some unconverted byproduct gas burned in a boiler along with natural gas. A portion of the project's electricity will be generated on site through a natural gas combined cycle power plant. It is assumed that 864 gigawatt hours of electricity will be purchased each year to supplement on-site power generation. Emissions from purchased power are accounted for as upstream emissions. A small quantity of natural gas is also combusted in a flare pilot. Fugitive emissions also occur from the methanol system and storage tanks.

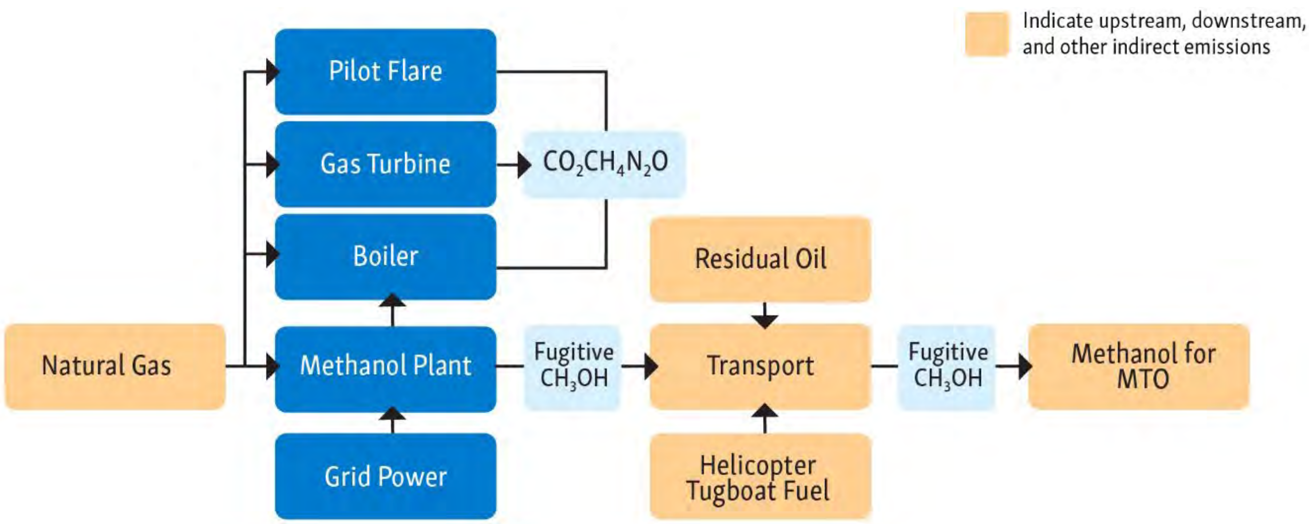


Figure 3-10. Direct Emissions Sources of Proposed Project

3.4.3.3 Downstream Inputs

Downstream emissions for the LCA include the transport of methanol from Kalama to Tianjin, China, by vessel. The inputs for the downstream analysis include both the emissions produced by the marine vessel and support vessels (e.g., pilot transport boats or helicopters, vessel assist tugs, etc.), and the emissions produced during the production of fuels used by these vessels in the transport process.

3.4.3.3.1 Marine Transport

GHG emissions from methanol transportation are based on transport from the proposed project site to Tianjin, China, a distance of approximately 5,341 nautical miles. Tianjin is a major industrial port city on the Bohai Sea and was selected as a representative port as several methanol to olefin production facilities are operating or planned there, and the port is also approximately equidistant from other major production centers in eastern China. The actual destination port is not fixed and may vary based on market demand. Marine transport includes fuel use for transporting the bar pilot to/from arriving/departing marine vessels by helicopter, tugboat assist operation in the Columbia River during docking and release, and the marine vessel transit to and from the representative destination port. The annual marine transport GHG emissions are proportional to the amount of methanol shipped. At full production capacity, this would result in 36 to 72 shipments to China per year. The model incorporates standard emissions factors for vessels and fuels.

3.4.3.3.2 Fuel Production

Petroleum fuels are used to transport methanol to Tianjin, as fuel for equipment during construction, and to produce and deliver natural gas, as well as for other aspects of the proposed project and alternatives evaluated. The upstream life-cycle emissions for fuel production include crude oil extraction, transport, oil refining, and delivery of the petroleum product.

GHG emissions from petroleum fuel production vary and depend on the crude oil type, the extraction method, and oil refinery configuration (Gordon, Brandt, Bergerson, & Koomey 2015; Keesom, Blieszner, & Unnasch 2012). The LCA of petroleum production in the GREET model takes into account the upstream emissions for crude oil production as well as the energy intensity to refine different products. The energy inputs and emissions within oil refineries are allocated with this approach between diesel, gasoline, residual oil, liquefied petroleum gas (LPG), naphtha, and coke. The GREET modeling approach assigns greater energy inputs to gasoline and diesel fuels and less to residual oil and naphtha because refinery units are designed to produce diesel and gasoline.

3.4.4 Model Scenarios

The LCA was run for multiple scenarios to provide a range of estimates of total GHG emissions that could be produced by the facility: baseline, lower, upper, and market mediated. The next sections summarize the assumptions and conditions involved in the analysis of each model scenario.

3.4.4.1 Baseline

The baseline scenario represents the most probable estimate among the key parameters. The operating conditions for the direct facility emissions reflect the start of run condition, which consumes slightly more energy than the end of run condition and is a conservative estimate ("run" refers to the life of the catalyst, which is approximately four years). The upstream life-cycle emissions of natural gas are based on a 99.4 percent British Columbia and 0.6 percent Rocky Mountain gas, which corresponds to the 2016 mix of net deliveries to Washington. Power generation emissions are based on the Washington mix, which results in conservatively higher GHG emissions than assuming the local Cowlitz PUD grid mix.

3.4.4.2 Lower

Several factors, including the availability of renewable power, could reduce the GHG emissions of the proposed project. This scenario examines the effect of power demand from the proposed project contributing to new loads of renewable power that will contribute to compliance with a renewable portfolio standard. The source of natural gas is based on all natural gas coming from British Columbia, which is anticipated to be the source of natural gas procured for the proposed project. The average operating conditions for the methanol facility are also used to determine direct facility emissions. These reflect the performance of the catalyst at the midpoint of its useful life. The lower emission scenario also includes higher upstream energy inputs for displaced methanol production and higher feedstock use rates for displaced methanol.

3.4.4.3 Upper

Of the four scenarios, the upper scenario represents the highest estimate of GHG emissions because of the assumed source of natural gas and mix of electricity. The combination of U.S. average upstream emissions for natural gas production and a marginal grid mix based on potential growth in electricity demand is examined here. Higher feedstock use rates and power generation emissions were assumed for displaced methanol. Higher emissions from displaced methanol result in lower overall emissions under this scenario.

3.4.4.4 Market Mediated

The market mediated scenario examines the second order market effects of a new source of methanol on markets. The proposed project is expected to increase the global methanol supply by approximately 3 percent. The potential effect of natural gas and coal feedstocks on energy markets is examined in this scenario. An increase in demand for natural gas for the proposed project or feedstocks for alternative sources of methanol could affect prices with effects on demand. This scenario uses the same energy input assumptions as the baseline scenario, but applies market mediated effects to the feedstocks for the proposed project and alternative sources of methanol.

3.4.5 Displaced Methanol

Methanol is a global commodity and is produced from various feedstocks at locations around the world. Current economic forecasts indicate continued increase in demand for methanol (Alvarado 2016). This analysis assumes that existing sources of methanol supply the growing demand on the east coast of China. Most of this demand is met with domestic Chinese production and some by imports. Most sources expect the growth in the demand for methanol to continue for the foreseeable future, and that low-cost imported product will continue to supply this region.

The LCA assessment of displacement effects considers economic trends, such as the new methanol units planned both in China (coal-based feedstock) and in the U.S. Gulf Coast (natural gas feedstock), that would supply the growing demand. These planned capacity additions represent a rebuilding of the methanol production capability that was nearly all shut down during the last decade because of the high cost of feedstocks. A market analysis of methanol production suggests that methanol produced by the proposed project would displace (or take the place of) methanol production processes that result in more expensive methanol. The analysis anticipates that the market would move from high-priced to lower-priced sources. The processes typically use coal as a feedstock and use coal-based power plants to provide electricity. Accordingly, GHG emissions from these processes would be displaced by alternative sources of methanol such as the proposed project.

Life-cycle GHG emissions for displaced methanol production are calculated in a similar method as that described for the proposed project (**Figure 3-11**). GHG emissions are based on the energy inputs and transport distance for the methanol plants that are displaced and assume that coal is the primary source for methanol feedstock and power generation. Methanol is transported in China by tanker truck, and the analysis assumes an average round-trip delivery distance from Chinese methanol manufacturers to Tianjin.

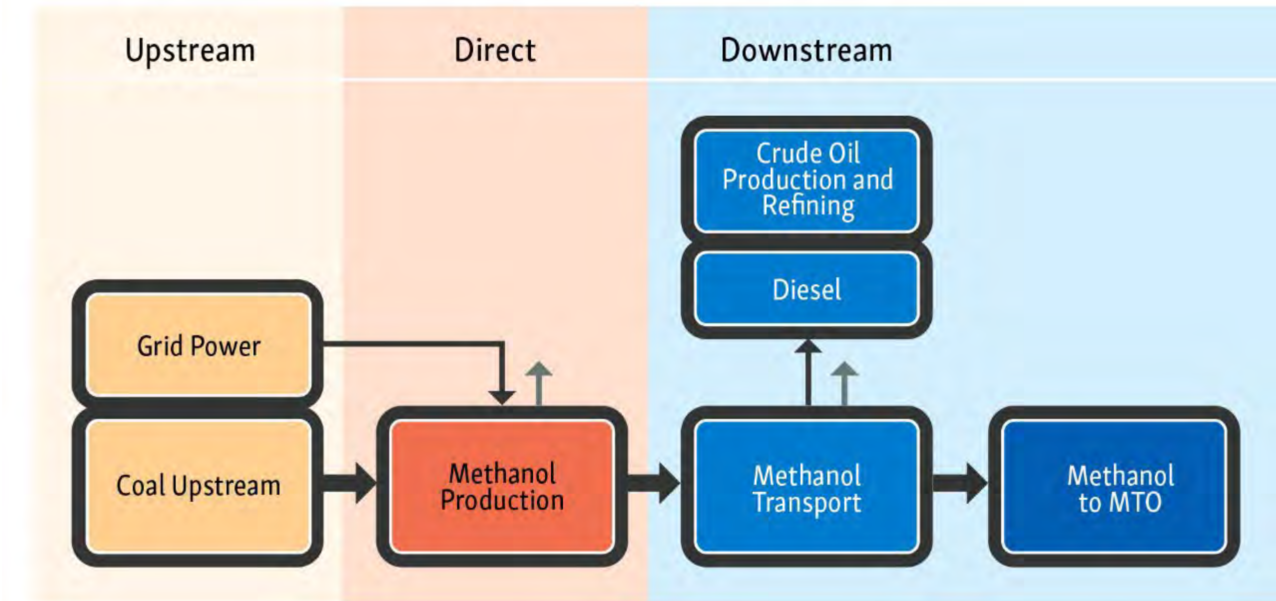


Figure 3-11. Grouping of Life-Cycle Coal to Methanol Emissions.

3.4.6 Methanol Use as Fuel

The proposed project is being developed specifically for the purpose of producing methanol for conversion to olefins. However, one of the many other uses of methanol is for fuel, including vehicle fuels. Methanol is also converted into products that are used as fuels. The potential for the proposed project to contribute to market changes that could affect the use of methanol generally as fuel are minimal, as global methanol capacity will only increase by only 3 percent. End-use demand for methanol as fuel is dictated by substantial primary market effects, including the price of crude oil and gasoline and consumer behavior. Given the response of consumer demand to price, a new source of methanol will not impact end-user demand or induce methanol-as-fuel market changes other than through secondary market effects, which are not of quantifiable significance.

A new source of methanol will not affect the end use demand other than through secondary market effects. Methanol plants in China operate at a relatively low capacity factor with expensive methanol. Because the existing excess capacity is not fully deployed to serve the fuel market, a new source of methanol should not shift expensive coal methanol into the fuel market. Substitution and displacement by methanol from the proposed project does not result in an increase in GHG emissions. Thus, GHG emissions from the use of methanol from the proposed project as fuel are not quantified further considered.

3.5 Environmental Impacts

3.5.1 Introduction

This section describes the life-cycle GHG emissions resulting from the construction and operation of the proposed project, including the No-Action Alternative. The life-cycle GHG emissions of the proposed project would be added to the global GHG emissions from past activities,[11] emissions from current activities, and the future emissions that would contribute to the cumulative increase in GHG emissions that result in climate change.

[11] It is not possible to determine with any certainty that the demand for natural gas production in North America will increase by the full amount consumed by the proposed project, and, therefore, the LCA analysis that assumes 100 percent of the upstream GHG emissions associated with natural gas demand from the proposed project is additive to global emission totals is a conservative assumption.

Because it is not possible to tie a particular climate change impact to individual emissions, it is not possible to identify or quantify specific direct impacts from the GHG emissions of the proposed project. Therefore, the impact analysis is inherently a cumulative impacts analysis of the indirect effects of the GHG emissions. It is the resulting climate change effects that take place in the future and distant from the project that are the relevant impacts. In this section, the impacts are based on GHG emissions and described separately by category and on an overall basis. To provide appropriate context and intensity for evaluation of impacts as required under SEPA, the GHG emissions are described in the context of both overall state and global GHG emissions levels.

In addition, this section evaluates the impacts of the CR Alternative and the No-Action Alternative along with the related actions for comparison with the ULE alternative selected by NWIW.

3.5.2 Construction Emissions

The LCA for construction GHG emissions includes direct emissions that occur at the project site and elsewhere in Washington. The LCA also includes GHG emissions that occur in other areas globally (such as the manufacturing of facility components) that may or may not be produced in Washington. **Table 3-3** shows the total direct and upstream GHG emissions for construction.

Table 3-3. Proposed Project Construction GHG Emissions by Source (metric tonnes)

Source		CO_2e
Direct	Diesel Equipment	4,933
	LPG Equipment	897
	Gasoline Commute	2,487
	Dredging Marine Fuel	6,694
	Dredging Organic C	1,609
Upstream (fuel use and purchased power)	Upstream Diesel	1,352
	Upstream LPG	205
	Upstream Gasoline, E10	776
	Upstream Marine Fuel	1,358
	Upstream Electricity	720
Upstream (construction materials)	Structural Steel	211,797
	Rebar	18,644
	Stainless Steel	178,589
	Copper	65,801
	Asphalt	17,963
	Aggregate	35,518
	Cement	46,338
Total		**595,681**

As noted in **Table 3-3** above, an estimated 595,681 metric tonnes of CO_2e emissions result from project construction over the three-year construction period. The majority of the GHG emissions result from production of materials used to construct the project and most of these emissions occur outside Washington State. Approximately 40,800 metric tonnes or 7 percent of the emissions occur in Washington primarily from combustion of fossil fuels. To calculate the annual emissions, the LCA divided the construction emissions across the estimated 40-year operational life span of the facility. When considered on this basis across the anticipated project lifetime, GHG emissions would be approximately 15,400 metric tonnes CO_2e total and 1,020 metric tonnes CO_2e in Washington.

This represents approximately 0.001 percent of the annual GHG emissions in the state and 0.000031 percent of annual global GHG emissions.

3.5.3 Operation Emissions – Upstream

Upstream emissions from the proposed project include emissions for natural gas extraction, processing, and transmission (production), as well as grid power generation. **Table 3-4** shows the upstream GHG emissions. Upstream GHG emissions occur both in and outside of Washington.

Table 3-4. Operations Emissions – Upstream (million metric tonnes per annum)

	Scenario			
Emissions Source	**Baseline**	**Lower**	**Upper**	**Market Mediated**
Upstream Natural Gas	1.04	1.03	1.23	1.04
Upstream Power	0.19	0.00	0.28	0.22
Total	1.23	1.03	1.51	1.26

As noted in **Table 3-4**, Operations Emissions – Upstream would result in between 1.03 million metric tonnes CO_2e and 1.51 million metric tonnes CO_2e emissions annually. This represents between 0.0021 percent and 0.0031 percent of annual global GHG emissions. Under the baseline scenario, approximately 175,200 metric tonnes CO_2e would be emitted annually in Washington, primarily from upstream power. This represents approximately 0.19 percent of the annual GHG emissions in the state.

3.5.4 Operation Emissions – Direct

Direct GHG emissions from the proposed project would result from the combustion of natural gas for on-site power and the unconverted CO_2 from the methanol production process. Additional direct emissions would result from natural gas combustion in the process boilers, flares, and diesel power emergency equipment, and fugitive emissions. **Table 3-5** shows GHG emissions from the direct emissions associated with the proposed project. These emissions result directly from operations that are the responsibility of NWIW. The scenarios (baseline, lower, etc.) discussed for other emission sources are not applicable to direct emissions and only the continuous operation scenario is shown, along with the numbers reported in the FEIS for comparison.

Table 3-5. Operation Emissions - Direct (metric tonnes CO2e per annum)

	Scenario	
Emissions Source	**Continuous Operation**	**FEIS**
Boilers	347,894	548,852
Firebox Heaters	0[12]	1,397
Flare Pilot	155	155
Flare	0[13]	3,175
Tank Vent Scrubber	5.6	5.6
Ship Vent Scrubber	3.4	0
Tanks	0.06	0.06

[12] During continuous operation no emissions occur from the firebox. If the firebox is in use, GHG emission from other sources would not occur, resulting in less overall GHG emissions.

[13] During continuous operation no emissions occur from the flare. If the flare is in use, GHG emission from other sources would not occur, resulting in less overall GHG emissions.

	Scenario	
Emissions Source	**Continuous Operation**	**FEIS**
Generators	273	273
Fire Pumps	45	45
Component Leaks	10.4	10.4
Combustion Turbine	379,620	421,000
Total	728,002	975,000

Note: Totals may not sum due to rounding.

The LCA calculated GHG emissions based on anticipated operations, while the calculations in the FEIS and the air permit are based on the maximum potential to emit based on maximum equipment capacity. Actual operations necessary to produce the annual methanol production do not subject the equipment to this level of operation on a continuous basis, and the LCA calculations are a more accurate representation of expected GHG emissions from direct facility operations.

As noted in **Table 3.5**, direct operations emissions result in GHG emissions of 0.73 million metric tonnes CO_2e per year. This represents approximately 0.0015 percent of annual global GHG emissions of 49 billion metric tonnes.

All of the GHG emissions in this category would occur in Washington. The 0.73 million metric tonnes per year would represent an approximately 0.8 percent increase in the annual GHG emissions in the state based on the 2013 inventory. Based on the 2016 GHG inventory report, this would represent the fifteenth largest emitter in the state of the individual emitters that are required to report emissions to Ecology. The NWIW previously agreed to limit GHG emissions on an annual basis from direct emissions, and this limitation is included in the air permit. The Shoreline Conditional Use Permit (SCUP) issued for the proposed project requires a reduction or offset of the emissions over time (see discussion in Section 3.6). In addition, the EPA has recognized the CR Technology as BACT for GHG for a methanol plant and established emissions limits on that basis for a new methanol plant permitted in Texas (EPA 2013). As described in section 4.4.1.2 of the FEIS, the ULE Alternative would result in approximately 31.3 percent less direct facility GHG emissions than the BACT CR Alternative and, thus, would exceed the standard for BACT.

3.5.5 Operation Emissions – Downstream

Downstream emissions from the proposed project include emissions resulting from the transport of methanol to Tianjin including the return trip. The emissions include those from burning fuel in the marine vessels and those from support activities (such as pilot boats and helicopters) as well as the life-cycle emissions associated with obtaining the fossil fuels. **Table 3-6** shows the downstream GHG emissions. These emissions occur in Washington (activities at the marine terminal, tug assist, pilot vessels/aircraft, and vessel transit) but also occur outside the state beyond the 3-nautical mile limit (vessel transit and activities at destination port).

Table 3-6. Operation Emissions – Downstream (million metric tonnes/annum)

Scenario	Baseline	Lower	Upper	Market Mediated
Downstream (total)	0.20	0.20	0.36	0.20

As noted in **Table 3-6**, downstream operations emissions would result in between 200,000 and 360,000 metric tonnes CO_2e emissions annually. This represents between 0.0004 percent and 0.0007 percent of annual global GHG emissions of 49 billion metric tonnes. Under the Baseline Scenario, approximately 4,890 metric tonnes CO_2e would be emitted annually in Washington, primarily from fuel production and use. This represents approximately 0.0052 percent of the annual GHG emissions in the state.

3.5.6 Methanol to Olefins

In addition to the downstream emissions associated with shipping, because the proposed project is intended to create methanol for the production of olefins, GHG emissions for the methanol-to-olefin process were also considered but not reflected in the overall LCA conclusion. This was done because the methanol to olefin process is the same for coal-based and natural gas-based methanol; it does not change the overall conclusion in the LCA.

GHG emissions from the 3.6 million tonnes of methanol per year used for the conversion to olefins would result in the emissions of 0.42 million metric tonnes of CO_2e per year. These GHG emissions are the same across all scenarios. None of these emissions would occur within Washington.

Another primary source of olefins is the conversion of naptha directly to olefins. Naptha is created from the crude oil refining process. The LCA evaluated the GHG emissions from this process and found it to have greater GHG emissions than the proposed project.

3.5.7 Proposed Project

Table 3-7 shows the annual estimated GHG emissions from the construction and operation of the proposed project as calculated in the LCA for the four scenarios: baseline, lower, upper, and market mediated. GHG emissions from construction are the same across all scenarios.

Table 3-7. Proposed Project Average Annual Life-Cycle GHG Emissions (million metric tonnes/annum)

Scenario		Baseline	Lower	Upper	Market Mediated
Construction	Direct	0.0004	0.0004	0.004	0.004
	Upstream	0.015	0.015	0.015	0.015
Operations	Upstream Natural Gas	1.04	1.03	1.23	1.04
	Upstream Power	0.19	0.00	0.28	0.22
	Direct	0.73	0.73	0.73	0.73
	Downstream	0.20	0.20	0.36	0.20
	Subtotal	**2.17**	**1.96**	**2.62**	**2.21**
Displaced	Upstream Feedstock	1.81	1.90	0.91	1.61
	Upstream Power	0.66	0.94	0.66	0.66
	Direct	10.92	11.47	10.40	10.92
	Downstream	0.30	0.30	0.30	0.30
	Displaced Subtotal	**13.69**	**14.61**	**12.27**	**13.49**
	Net Emissions	**-11.5**	**-12.6**	**-9.6**	**-11.3**

Construction would occur over a three-year period prior to operation of the proposed project. To determine the annual GHG emissions, the LCA divided the construction GHG emissions across the 40 years of operations, the anticipated operational period of the facility. Operational GHG emissions, including on-site direct emissions and upstream and downstream emissions from the natural gas feedstock, power generation, and shipping, range from 1.96 to 2.62 million metric tonnes CO_2e per year depending on the scenario.

Methanol from the proposed project will displace methanol from other sources. Coal-based methanol produced in China has higher market costs than methanol from the proposed project, which is calculated to be one of the lower cost products with access to the China market. Therefore, additional methanol provided to China stands to displace methanol from the high cost coal-based resources. The displaced coal-based methanol would result in a reduction in GHG emissions. Life-cycle GHG emissions from coal-based methanol are approximately 5.5 to 6.2 times higher than life-cycle GHG emissions from the proposed project. Emissions displaced by the project would result in a reduction in GHG emissions of between 14.61 and 12.27 million metric tonnes CO_2e per year. This results in the potential for a net reduction in overall cumulative GHG emissions from the proposed project of between 9.6 and 12.6 million metric tonnes CO_2e manually.[14]

Figure 3-12 compares the GHG emissions from upstream, direct, and downstream effects from the proposed project and those displaced by the proposed project under the baseline scenario. The size of the chart is proportional to the volume of GHG emissions or displaced GHG emissions.

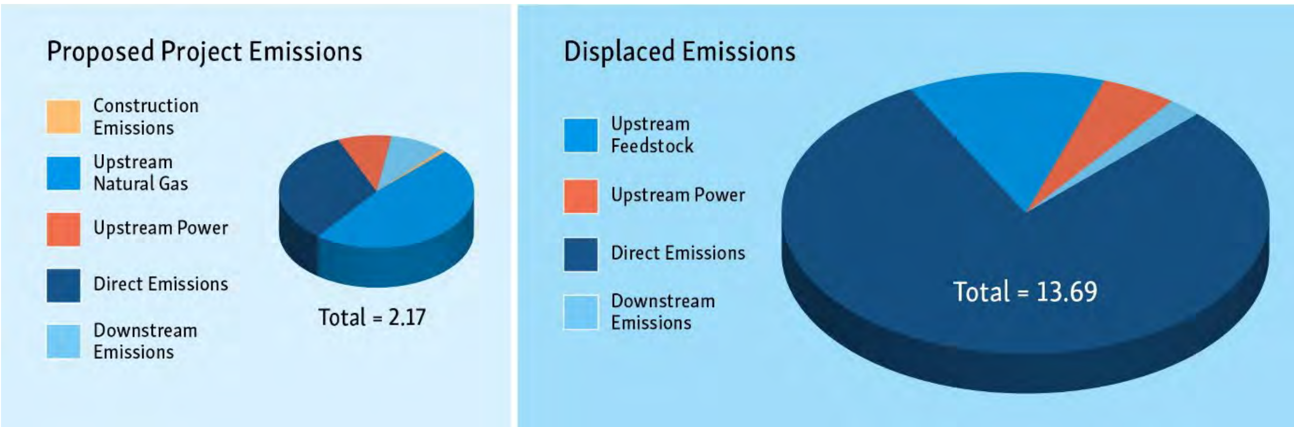


Figure 3-12. Proposed Project Emissions and Displaced Emissions by Source

3.5.8 Life-Cycle Emissions – Washington State

The LCA estimates that the proposed project will result in the emissions of approximately 0.96 million metric tonnes of CO_2e per year in Washington, including upstream, direct, and downstream emission sources. **Figure 3-13** shows the proposed project emission sources in Washington State.

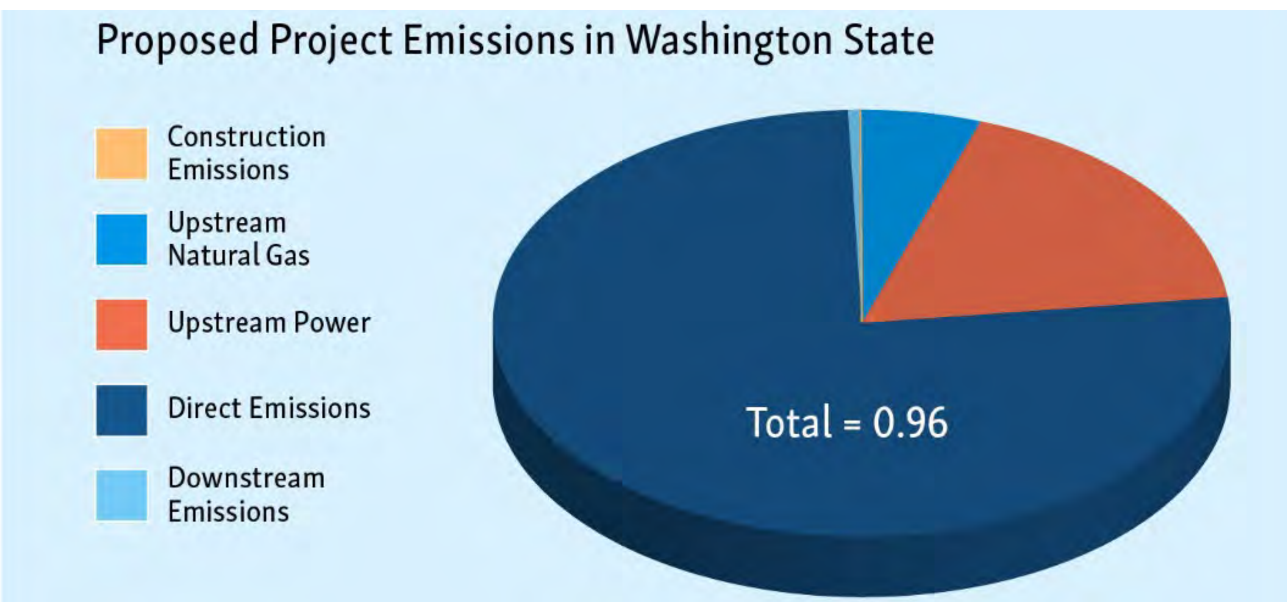


Figure 3-13. Proposed Project GHG Emissions by Source in Washington State (million metric tonnes)

[14] Using the 20-year GWP would result in GHG emission reductions of between 10 and 14.5 million metric tonnes CO_2e annually.

The 0.96 million metric tonnes This total represents approximately 1.02 percent of statewide 2013 GHG emissions and, without consideration of any other changes to statewide GHG emissions or the market displacement effects described in Section 3.5.7, could contribute to an increase in overall statewide GHG emissions above current levels.

In 2008, Washington adopted statewide GHG emission reduction goals to establish an overall framework to guide state planning and regulatory efforts to address GHG emissions and climate change (see RCW 70.235 discussed in Section 3.3.3.1). The statute anticipated development of future plans and regulations to address GHG emission requirements.

RCW 70.235.005 establishes the legislative intent of these GHG reduction goals as follows.

> *(3) It is the intent of the legislature that the state will:*
> - *(a) Limit and reduce emissions of greenhouse gas consistent with the emission reductions established in RCW 70.235.020;*
> - *(b) minimize the potential to export pollution, jobs, and economic opportunities; and*
> - *(c) reduce emissions at the lowest cost to Washington's economy, consumers, and businesses.*

RCW 70.235 does not provide direction to or requirements to restrict or regulate particular projects, emissions sources, or emissions sectors, with the exception of the RCW 70.23.050 requirement that state agencies meet the emission limits of RCW 70.235.020. The limits established RCW 70.235.020 are statewide and apply across all sources of GHG emissions.

Even though the proposed project will result in GHG emissions, it is not possible to judge from project emissions alone whether the state will or will not meet the requirements of RCW 70.235. The Governor's Carbon Emissions Reduction Task Force has the mission of providing "recommendations on the design and implementation of a carbon emissions limits and market mechanisms program for Washington." The task force found that reaching the reductions specified by RCW 70.235 will require a comprehensive policy approach, including the need to focus on the transportation sector because of the unique nature of the state's GHG emission profile (Carbon Emissions Reduction Task Force 2014).

The statewide GHG emissions inventory (Ecology 2016a) shows that GHG emissions consist of GHG emissions from many different sectors and sources. These GHG emissions may increase or decrease over time according to many factors, and those changes may vary from one sector to another. For example, the TransAlta Centralia coal-fired power plant (the largest single emitter of GHG emissions in the state) is scheduled for closure beginning in 2020. Another large emission source in the state, the Camas paper mill operated by Georgia-Pacific has recently shut down parts of its operations, including its GHG emission-intensive pulping operations (The Columbian 2017). Other actions are resulting in reductions. Per RCW 19.27A.020(2)(a), the Washington state energy code shall be designed to require increasingly energy-efficient buildings to help meet the broader goal of building zero fossil-fuel GHG emitting homes and buildings by the year 2031. These increasingly stringent energy codes have resulted in a 24 percent reduction in energy consumption for new residential structures over 2006 and an 18 percent reduction for commercial buildings over the same time period (Washington State Building Code Council 2012). Similarly, emissions from transportation may increase or decrease, depending on vehicle miles traveled, federal mileage standards, the increased use of electric vehicles, and the state's progress towards meeting the goals of RCW 47.01.440.

Because RCW 70.235 was not intended to impose project-specific GHG limitations and almost any new project action (industrial or otherwise) will constitute a new source of GHG emissions, it is not appropriate to evaluate project GHG emissions in isolation when evaluating consistency with the legislative policy articulated in RCW 70.235. Instead, the project GHG emissions should be evaluated in the context of GHG emission reductions occurring in other sectors as well as the market displacement effect on global GHG emissions. When viewed in this context, the GHG emissions from the project are not inconsistent with the state GHG reduction goals in RCW 70.235.

3.5.9 Combined Reformer Alternative

The LCA did not include a complete analysis of the CR Alternative as NWIW has committed to use the ULE Alternative in constructing and operating the proposed project. Chapter 4 of the FEIS evaluated the emissions of the CR Alternative as compared the ULE Alternative. GHG emissions from facility operations (including on-site power generation) (see Table 4-4 of the FEIS) would be 31.3 percent higher for the CR Alternative than the ULE Alternative. However, the CR Alternative would require one-third less purchased power than the ULE Alternative and would result in fewer emissions from that element of the upstream emissions. Conversely, the CR Alternative would require more natural gas than the ULE Alternative and would result in an increase in that element of the upstream emissions. Because the same volume of methanol would be produced and it would be transported in the same manner in both alternatives, the downstream emissions of the alternatives would be the same. Overall, the CR Alternative would result in greater GHG emissions than the ULE Alternative.

3.5.10 No-Action Alternative

Under the No-Action Alternative, the proposed project would not be constructed on the project site. Given the site’s highway, rail, and waterfront access and the Port's Comprehensive Scheme for Harbor Improvements, it is expected that, absent the proposed project, the Port would pursue other industrial or marine terminal development of the site. That development could result in GHG emissions that would be similar to, or greater or less than, the GHG emissions for the construction and operation of the proposed project.

The LCA assessed the impact of the proposed project on the methanol market and identified other sources of methanol that could be displaced by the construction and operation of the proposed project. The cost advantages of producing and shipping methanol from the proposed project could displace methanol production from existing coal-based plants in China and should discourage the development of new coal-based methanol plants. Most of China’s existing, and potential for expanded, methanol capacity is coal-based, which has much greater GHG emissions for each unit of methanol produced. Market forces would be expected to drive the methanol market to prefer less expensive methanol manufactured from natural gas over higher cost methanol from coal. The proposed project is estimated to displace the production of 3.6 million metric tonnes per year of methanol by the existing or proposed coal-based sources, which would result in the displacement of over 7 million metric tonnes per year of coal and the increased use of 2.2 million metric tonnes per year of natural gas. This would result in the displacement of between 12.3 and 14.6 million metric tonnes of GHG emissions. This displacement effect would not occur under the No-Action Alternative and, thus, the No-Action Alternative would result in greater emissions than the construction and operation of the proposed project.

3.5.11 Related Actions

3.5.11.1 Proposed Pipeline

Northwest Pipeline is proposing to permit, construct, and operate the 3.1-mile, 24-inch-diameter natural gas pipeline to provide a natural gas supply to the proposed project. The proposed pipeline underwent a separate permitting process under the jurisdiction of the Federal Energy Regulatory Commission (FERC).

The construction of the proposed pipeline would involve excavation and drilling activities at a much smaller scale of disturbance than with the proposed project. Such activities would result in GHG emissions from construction-related sources, although on a much smaller scale. Approximately 1,000 short tons of CO_2 would result from direct construction emissions (FERC 2015).

There are no permanent sources of operational emissions from the proposed pipeline with the exception of minor fugitive methane emissions. Fugitive emissions may result in small amounts of pollutants, while maintaining the permanent right-of-way may result in small amounts of pollutants from mowing, cutting, and trimming. These emissions would be minor and less than the cutoff criteria within the LCA.

3.5.11.2 Electrical Service

The electrical service-related action would result in limited construction and operational activities and would not introduce new permanent sources of air emissions. Any contribution to GHG emissions would be minor and associated with construction and would not add to the impacts identified above.[15]

3.6 Impact Significance

This section summarizes how the project impacts identified above are evaluated for significance in the context of SEPA and established rules.

WAC 197-11-794 defines significance as follows.

- Reasonable likelihood of more than a moderate adverse impact on environmental quality.
- Involves context and intensity and does not lend itself to a formula or quantifiable test. The context may vary with the physical setting. Intensity depends on the magnitude and duration of an impact.
- The severity of an impact should be weighed along with the likelihood of its occurrence. An impact may be significant if its chance of occurrence is not great, but the resulting environmental impact would be severe if it occurred.

WAC 197-11-330 provides further guidance in evaluating significance.

- A proposal may have a significant adverse impact in one location but not in another location.
- The absolute quantitative effects of a proposal are also important, and may result in a significant adverse impact regardless of the nature of the existing environment.
- Several marginal impacts when considered together may result in a significant adverse impact.
- It may be impossible to forecast the environmental impacts with precision, often because some variables cannot be predicted or values cannot be quantified.
- A proposal may to a significant degree:
  - Adversely affect environmentally sensitive or special areas;
  - Adversely affect endangered or threatened species or their habitat;
  - Conflict with local, state, or federal laws or requirements; and
  - Establish a precedent for future actions with significant effects, involve unique and unknown risks to the environment, or may affect public health or safety.

Given the global nature of GHG emissions and climate change impacts, a global context is the most appropriate for evaluating impact significance. Additionally, because the state has identified GHG reduction targets in RCW 70.235, GHG emissions may also be evaluated in that context at the state level.

[15] This does not address emissions from purchased power transmitted over the proposed electrical service improvements. Accounting of GHG emissions from purchased power is fully addressed in Section 3.5.3.

The significance of an impact must also be considered after application of any mitigation that is proposed by the project proponent as part of the project, including the project design and any mitigation that is required by regulations, permits, or permits conditions, or otherwise required by an agency. After consideration of all of the above, a determination is made on whether an unavoidable significant adverse impact remains that is attributable to the proposed project.

Total life-cycle GHG emissions attributable to the proposed project are between 1.97 to 2.62 million metric tonnes of CO_2e per year. Adding the methanol to olefin process downstream, GHG emissions would increase to 2.39 to 3.04 million metric tonnes per year.

Emissions displaced by the project would result in emission reductions of as much as 14.61 million metric tonnes of CO_2e per year. This results in a net reduction in overall cumulative GHG emissions of between 9.6 and 12.6 million metric tonnes of CO_2e per year from the proposed project. **Table 3-8** summarizes the proposed project GHG emissions based on the Baseline Scenario both globally and within the state.

Table 3-8. Proposed Project Annual GHG Emissions Summary (Baseline Scenario)

Location	Source	Emission Increase/Decrease (million metric tonnes)	Percent Change in Emissions*
Washington State	Construction	0.001	0.001 percent
	Operations – Upstream	0.17	0.19 percent
	Operations – Direct	0.73	0.8 percent
	Operations –Down Stream	0.0049	0.0052 percent
	Total	**0.96**	**1.02 percent**
Global	Construction	0.0154	0.000031 percent
	Operations – Upstream	1.23	0.0025
	Operations – Direct	0.73	0.0015
	Operations –Down Stream	0.20	0.00041 percent
	Displaced -Upstream Feedstock	-1.81	-0.0037 percent
	Displaced - Upstream Power	-0.66	-0.0013 percent
	Displaced - Direct Emissions	-10.92	-0.022 percent
	Displaced -Downstream Emissions	-0.30	-0.00061 percent
	Total	**-11.5 million metric tonnes**	**- 0.023%**

*Based on 2013 levels for Washington and 2016 levels for global.

3.7 Mitigation Measures

This section summarizes mitigation measures that are part of the proposed project and additional mitigation that may be implemented to address specific project impacts. The SEPA Rules (WAC 197-11-768) define mitigation as:

(1) Avoiding the impact altogether by not taking a certain action or parts of an action;

(2) Minimizing impacts by limiting the degree or magnitude of the action and its implementation, by using appropriate technology, or by taking affirmative steps to avoid or reduce impacts;

(3) Rectifying the impact by repairing, rehabilitating, or restoring the affected environment;

(4) Reducing or eliminating the impact over time by preservation and maintenance operations during the life of the action;

(5) Compensating for the impact by replacing, enhancing, or providing substitute resources or environments; and/or

(6) Monitoring the impact and taking appropriate corrective measures.

The ULE Alternative was investigated and selected by NWIW for the purpose of reducing air emissions that the CR Alternative would otherwise produce. The selection and use of the ULE technology itself is a mitigation measure as it minimizes impacts by reducing GHG emissions as compared to other suitable and available methods of methanol production. NWIW has committed to the construction of the ULE Alternative. All other methanol plants currently proposed or recently permitted for construction in the United States are based on the CR technology or another traditional technology with GHG emissions similar to those of the CR technology. The EPA recently recognized the CR technology as BACT for GHG for a methanol plant and established emission limits on that basis for a new methanol plant permitted in Texas (EPA 2013). The FEIS concluded that emissions from the ULE Alternative process (including on-site power generation) would be 31.3 percent lower with the ULE Alternative than with the CR Alternative (see Table 4-4 of the FEIS). The emissions based on the ULE Alternative are reflected in the GHG emission limit of 1,076,000 tons[16] included in the SWCAA-issued Air Discharge Permit.

The proposed project also incorporates the use of shore power for the marine terminal. Shore power allows ships to “plug into” electrical power sources on shore. Turning off ship auxiliary engines at berth would reduce ship diesel emissions and result in GHG emission reductions, depending on the source of electric power from the grid. GHG emission reductions from shore power have not been calculated for the proposed project, but studies completed in other locations show reductions of from 25 percent to 50 percent (EPA 2017).

Other methods to reduce GHG emissions will be employed by the proposed project during both construction and operations. These may include encouraging carpooling, bicycling, and other similar commuting modes; establishing no-idle policies for on-site combustion power vehicles and equipment; installing electric car charging stations; installing energy-efficient equipment; and other similar methods.

[16] This emission limit is reflected in short tons.

The SCUP was issued with a number of conditions, including Condition 4, which requires the project to reduce or offset GHG emissions until 2035, either through the Clean Air Rule or as specified in the condition. The text of Condition 4 reads as follows:

1. *Northwest Innovation Works (NWIW) is required to mitigate for greenhouse gas emission covered under Chapter 173-441 WAC originating from its facility. This mitigation requirement is to be met by demonstrating achievement or acquisition of greenhouse gas emission reductions on an annual basis as follows:*

    a. *For any year that the facility has been assigned an emission reduction pathway under the Clean Air Rule (Chapter 173-442 WAC), an approved compliance report submitted as the end of the applicable Clean Air Rule compliance period will satisfy the mitigation requirement for that year.*

    b. *For any year that the facility has not been assigned an emission reduction pathway under, or is not subject to, the Clean Air Rule, the mitigation requirement for that year:*

        i. *Is an amount of greenhouse gas emission reductions (metric tons of carbon dioxide equivalent) equal to the product of the following three factors:*

            1. *A cumulative rolling average of the total greenhouse gas emissions reported from the facility in accordance with Chapter 173-441 WAC, with the cumulative average beginning in the first full year of operation and turning into a five-year rolling average in the fifth year.*

            2. *An emission reduction factor of one and seven-tenths percent (1.7%).*

            3. *The number of years from the first calendar year of operations at NWIW with emissions reported under Chapter 173-441 WAC to the year in which the emission reduction requirement is being calculated, or to the year 2035, whichever is less.*

        ii. *Can be met in two ways:*

            1. *Demonstration that some or all of the mitigation requirement is achieved through reductions in greenhouse gas emissions at the facility if the greenhouse gas emissions reported for the applicable year in accordance with Chapter 173-441 WAC are lower than the rolling average calculated in (b)(i)(l) above.*

            2. *Acquisition of qualifying emission reductions through the purchase of carbon credits or by investing in or facilitating the creation of emission reduction projects in accordance with a mitigation plan approved by Ecology.*

    NWIW is to provide an annual report, due by December 31 of the year following the emissions year, to Ecology describing the manner in which the mitigation requirement is met. If NWIW is complying with this mitigation requirement using the method in (4)(a) above, then the compliance report specified in WAC 173-442-210 will meet this requirement.

Compliance with this condition would result in the reduction of GHG emissions over time from the direct operations emissions described in section 3.5.4. Direct operation emissions resulting from the project are 0.73 million metric tonnes initially (starting in 2022) and when reduced or offset by the 1.7 percent reduction every year required by Condition 4, the resulting emissions in 2035 would be approximately 0.57 million metric tonnes.

Globally, displacement effects from the construction and operation of the proposed project will result in an annual reduction of 11.5 million metric tonnes of GHG under the baseline scenario.

This is the equivalent of the amount of carbon stored by 821,000 Douglas fir trees over the first 100 years of their life being eliminated from the environment annually. Given this overall global net reduction in GHG emissions and the conditions of approval established by the issued shoreline permits (including Condition 4) the result is no significant unavoidable adverse impacts from global GHG emissions.

In furtherance of NWIW's stated goal of reducing GHG emissions globally through cleaner, less GHG-intensive methanol production, NWIW additionally proposes to voluntarily mitigate for 100 percent of all GHG emissions occurring within Washington as result of the proposed project, including those outside of NWIW's control and those which would occur with or without project construction. If emission values remain constant over the life of the mitigation program, NWIW will mitigate for up to 38.4 million metric tonnes of GHG emissions, the equivalent of the amount of carbon stored by 2,742,000 Douglas fir trees over the first 100 years of their life.[17]

In year one, the GHG mitigation program will compensate for the approximately 960,000 metric tonnes of GHG emissions estimated by the LCA to be emitted within the state boundaries and state waters.[18] The GHG mitigation program proposes to fully eliminate or offset on-site emissions from the direct operation emissions, emissions from project construction (as distributed over the project's 40-year life), emissions related to gas distribution within Washington, and emissions from marine vessel traffic and supporting activities in state waters. This mitigation measure would also serve to implement and would exceed the requirements of Condition 4 from the SCUP discussed above and thus satisfy that condition.

This voluntary mitigation may be accomplished through a variety of methods, including

1. The purchase of verified carbon credits through carbon credit markets or banks; or
2. The payment of an amount comparable to No. 1 above into a GHG mitigation fund.[19]

NWIW's full GHG mitigation program will continue for the life of the proposed project, currently estimated to be 40 years, following commencement of operations or until there is a comparable national, state, or local programmatic, regulatory, or statutory framework for reducing and/or mitigating GHG emissions (including, for example, imposition of a carbon tax or GHG emission cap and/or reduction programs for industrial facilities) that directly applies to the proposed project and replaces some or all of the full mitigation level contemplated.

3.8 Unavoidable Significant Adverse Impacts

Given the overall net reduction of global GHG emissions as a result of this project, there are no unavoidable significant adverse impacts from the proposed project at the global level.

In addition, because NWIW has voluntarily proposed to mitigate for 100 percent of all GHG emissions that occur within Washington—including those that are outside of the facility operations—and NWIW's control, through GHG reductions, purchase of verified carbon credits, or payment of a comparable amount into another GHG mitigation fund, means the project will have no unavoidable significant adverse impacts at the state level.

[17] See https://www.fs.usda.gov/ccrc/tools/tree-carbon-calculator-ctcc.
[18] The total volume GHG emissions subject to mitigation may decrease over time based on actual direct operation emissions.
[19] For example, although carbon market prices vary, $4.50/tonne for CO_2e is the clearing price from the most recent Regional Greenhouse Gas Initiative auction held on September 5, 2018. See https://www.rggi.org/auctions/auction-results.

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Appendix A: Kalama Manufacturing and Marine Export Facility Supplemental GHG Analysis


Kalama Manufacturing and Marine Export Facility Supplemental GHG Analysis

LCA.6132.185.2018
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DISCLAIMER

This report was prepared by Life Cycle Associates, LLC under contract with Northwest Innovation Works for use by and under the direction of the Port of Kalama and Cowlitz County in the state of Washington as the State Environmental Policy Act (SEPA) co-lead agencies preparing a Supplemental Environmental Impact Statement (Supplemental EIS) for the development and operation of a natural gas-to-methanol production plant and storage facilities at the Port of Kalama. Life Cycle Associates is not liable to any third parties who might make other use of this work. No warranty or representation, express or implied, is made with respect to the accuracy, completeness, and/or usefulness of information contained in this report beyond the above stated use. Finally, no liability is assumed with respect to the use of, or for damages resulting from the use of, any information, method or process disclosed in this report beyond the above stated use. In accepting this report, the reader agrees to these terms.

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TERMS AND ABBREVIATIONS

ANL	Argonne National Laboratory
ARB	California Air Resources Board
Btu	British Thermal Unit
CA	California
CA-GREET	The standard GREET model modified for use in CA LCFS
CH_4	Methane
CI	Carbon intensity
CIG	Climate Impacts Group
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2c	Fully oxidized fuel emissions including CO2, VOC, and CO
CO_{2e}	Carbon dioxide equivalent
CTO	Coal to Olefins
CY	Cubic yard
DME	Dimethyl Ether
DOE	U.S. Department of Energy
EIA	US Energy Information Agency
EOR	End of Run
EPA	U.S. Environmental Protection Agency
FEIS	Final Environmental Impact Statement
g CO_2e	Grams of carbon dioxide equivalent
GBtu	Giga Btu, 10^9 Btus
GHG	Greenhouse Gas
GHGenius	LCA model based on UC Davis Life Cycle Emission Model (LEM) that was developed for Natural Resources Canada
GREET	The Greenhouse gas, Regulated Emissions, and Energy use in Transportation model
GWh	Gigawatt Hours
GWP	Global Warming Potential
HC	Hydrocarbon
HHV	Higher Heating Value
IPCC	Intergovernmental Panel on Climate Change
ISO	International Standards Organization
JRC	Joint Research Centre

KMMEF	Kalama Manufacturing and Marine Export Facility
kn	nautical mile
ktpa	kilo tonne per annum
LCA	Life Cycle Analysis or Life Cycle Assessment
LCI	Life Cycle Inventory
LCFS	Low Carbon Fuel Standard
LHV	Lower Heating Value
mmBtu	Million Btu
MTBE	Methyl tertiary butyl ether
MTO	Methanol to Olefin
MTPA	Million Metric Tonnes per Annum
MW	Megawatt
N_2O	Nitrous oxide
NETL	National Energy Technology Laboratory
NG	Natural gas
NOx	Oxides of nitrogen
NWIW	Northwest Innovation Works, LLC –Kalama
NWP	Northwest Pipeline
PDH	Propane De-Hydrogenation
PUD	Public Utility District
RFS2	Revised Federal Renewable Fuels Standard
RPS	Renewable Portfolio Standard
SEIS	Supplemental Environmental Impact Statement
SEPA	(Washington) State Environmental Policy Act
SOR	Start of Run
ULE	Ultra Low Emission
UN	United Nations
UNFCC	United Nations Framework Convention on Climate Change
VOC	Volatile Organic Compound
WTT	Well-To-Tank
WTW	Well-To-Wake

EXECUTIVE SUMMARY

Northwest Innovation Works, Kalama, LLC (NWIW) and the Port of Kalama are proposing to construct the Kalama Manufacturing and Marine Export Facility (KMMEF). NWIW proposes to develop and operate a natural-gas-to-methanol production plant and storage facilities on approximately 90 acres at the Port of Kalama. KMMEF would be located on the Columbia River at the Port's North Port site (EIS Ch 2). It would be operated by NWIW and produce methanol for shipment from a newly constructed dock. The anticipated annual production capacity would be approximately 3.6 million tonnes. The methanol is intended for the production of olefins (methanol to olefin or "MTO"), which are the primary components in the production of consumer products, such as plastics, medical devices, glasses, contact lenses, recreational equipment, clothing, cell phones, furniture, and many other products.

The KMMEF is required to be reviewed for impacts to the built and natural environment under the State Environmental Policy Act (SEPA) for the state of Washington and further analysis of greenhouse gas (GHG) emissions has been commissioned to understand the upstream and downstream emissions emitted either directly or indirectly by the project. This study follows the process for Life Cycle Assessment defined by international standards and examines GHG emissions on a life cycle basis. The emissions from the KMMEF are compared to the GHG emissions from alternative sources of methanol production using the GREET and GHGenius framework to calculate emission rates.

The focus of the study was to present data on the following sources of emissions on a life cycle basis.

(1) GHG emissions attributable to construction of the project;
(2) Onsite direct GHG emissions from the project;
(3) GHG emissions from purchased power, including consideration of the potential sources of generation that would satisfy the new power needs;
(4) GHG emissions potentially attributable to the project from natural gas production, collection, processing and transmission;
(5) GHG emissions from the shipping of methanol product to a representative Asian port; and
(6) GHG emissions associated with changes in the methanol industry and related markets that may be induced by the Project's methanol production, including the potential use of methanol generally as fuel and any changes to the facility design that affect GHG emissions

Key Findings

The Study analyzed emissions using three principle scenarios for methanol production, Baseline, Lower and Upper. Estimating GHG emissions up and downstream from the KMMEF facility requires assumptions about a number of variables or parameters (e.g., power generation mix of electricity used onsite). The likely accuracy of any parameter is difficult to predict. Thus this Study includes three scenarios—Baseline, Lower and Higher— to produce a range of reasonable assumptions from low to high. The Baseline scenario reflects the best estimate of expected emissions with conservative assumptions regarding KMMEF operations, natural gas production, power generation mix as well as factors affecting the production of displaced methanol. A further market mediated scenario is also provided as reference in the document to capture potential secondary economic impacts. Because the market mediated scenario results fell with that Baseline, Lower and Upper scenarios, those results are not illustrated in this executive summary.

The Study reviews the use of naphtha as an alternative feedstock for olefins production. Naphtha has been and continues to be the predominant feedstock for Chinese olefin production but, since the inception of the MTO process in 2010 methanol has reduced naphtha's market share and is expected to continue to do so. As naphtha based olefin production has 10% higher GHG emissions than MTO derived from KMMEF sourced methanol any displacement by KMMEF methanol would result in slightly lower global emissions than naphtha to olefins. If this displacement of olefins from naphtha rather than from methanol occurred through coal based methanol, instead of natural gas to methanol, global emissions would increase.

The Study also reviews emissions related to the use of methanol as a fuel to compare those fuel emissions to alternative soure of fuel. NWIW has firmly committed KMMEF methanol to MTO production, but it was felt that this large methanol fuel market should be reviewed, particularly since this question was raised during SEIS scoping. This analysis concludes that in its primary fuel market, gasoline blending, KMMEF methanol blends would result in GHG emissions that are very similar to or posibly marginally less than those for straight gasoline. Thus, even under a KMMEF methanol to fuel, the GHG emission comparisons to gasoline would not be significantly different. Gasoline blends using coal based methanol result in higher emissions. KMMEF methanol would result in lower GHG emissions for applications such as cooking fuel where coal is displaced. Again, KMMEF methanol is firmly targetted to the MTO market so this analysis is simply provided as general comparative information.

This Study finds that demand for methanol, most notably in the MTO market in China, is going to be sustained and is projected to continue to grow. This growth will occur with or without the KMMEF. Annual life cycle GHG emissions from the KMMEF are shown in Table S.1.

Based on a detailed analysis of global methanol to olefin markets, this Study also concludes that continued growth of the use of Chinese coal as a feedstock for methanol production is the most likely alternative manufacturing method for methanol if the KMMEF project is not built. The KMMEF will add about 3% capacity to the global methanol supply in a growing market. Absent this supply, new sources of coal-based methanol would be built, or existing coal-based methanol capacity would be deployed to meet the relatively inelastic (insensitive to changes in price) demand for methanol. The Study calculates emissions from this alternative to methanol manufacturing method as shown in Table S.2.

Table S.1. Annual GHG Emissions from KMMEF Methanol

Scenario	Emission (million tonnes/annum)		
	Baseline	Lower	Upper
Construction Emissions			
Direct	0.0004	0.0004	0.0004
Indirect	0.015	0.015	0.015
Operational Emissions			
Upstream Natural Gas	1.04	1.03	1.23
Upstream Power	0.19	0.00	0.28
Direct Emissions[b]	0.73	0.73	0.73
Downstream Emissions	0.17	0.17	0.30
Transport Fuel Production	0.03	0.03	0.06
KMMEF Total[c]	**2.17**	**1.96**	**2.62**

[a] Construction emissions are distributed over a 40-year project life.
[b] Emissions correspond to continuous operation which are lower than maximum emission rates from equipment in the FEIS.
[c] Totals may not sum due to rounding.

Table S.2. Annual GHG Emissions from Displaced Coal to Methanol

Scenario	GHG Emission (million tonne CO_2e/annum)		
	Baseline	Lower	Upper
Upstream Feedstock	1.81	1.90	0.91
Upstream Power	0.66	0.94	0.66
Direct Emissions	10.92	11.47	10.40
Downstream Emissions	0.24	0.24	0.24
Transport Fuel Production	0.06	0.06	0.06
Displaced Total	**13.69**	**14.61**	**12.27**

The detailed economic analysis in this report indicates that production costs for the KMMEF facility are significantly lower compared to the alternative of coal-to-methanol production costs in China, including transport of the methanol to the olefin facilities in China. As discussed in sections 4.4 and 4.5, this cost difference will result in displacing methanol from coal-based production facilities in China with that of methanol produced using natural gas at the KMMEF as shown in Table S.3.

Table S.3. Annual Net GHG Emissions Reduction using KMMEF Methanol as compared to Coal to Methanol

Scenario	GHG Emission (million tonne CO_2e/annum)		
	Baseline	Lower	Upper
Net Emissions Reduction	**11.5**	**12.6**	**9.7**

This displacement will drive a significant reduction in net global GHG emissions. This life cycle analysis of KMMEF GHG emissions concludes that GHG emissions will be reduced by 3000 kg for every tonne of methanol produced at KMMEF, with KMMEF methanol displacing coal to methanol in the global market, as shown in Figure S.1[1]. The contribution of the feedstock, imported power, on-site production, and transport emissions are shown in the figure below. The differences in GHG emissions are due to many factors including the CO_2 intense coal feedstock and inefficiency of coal to methanol, upstream life cycle emissions associated with natural gas, electric power, and coal production, as well as the efficiency of KMMEF methanol transport.

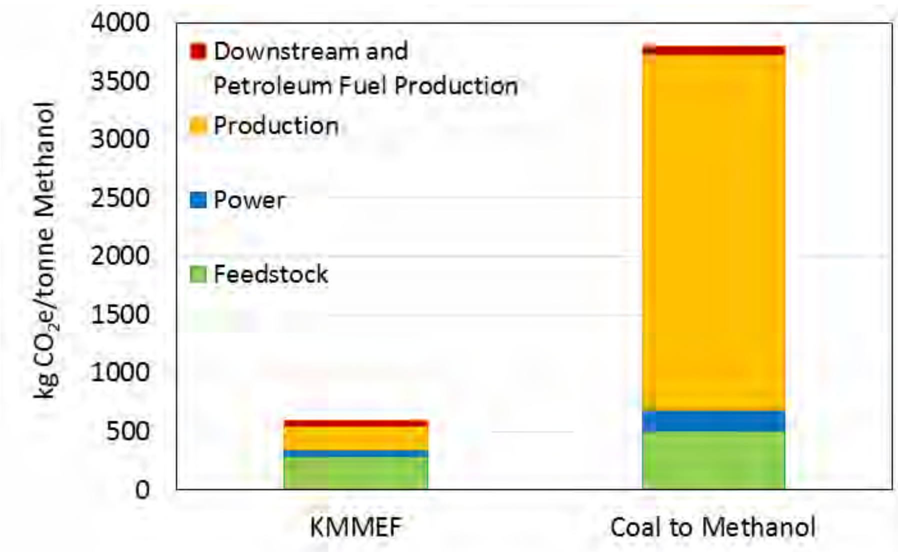

Figure S.1. Life cycle GHG emissions from KMMEF methanol and coal to methanol.

Conclusion

Total life cycle emissions associated with KMMEF operation range from 1.96 to 2.62 million tonne CO_2e/year. Total life cycle emissions associated with displaced coal to methanol production range from 12.3 to 14.6 million tonne CO_2e/year with net GHG emission reductions ranging from 9.7 to 12.6 million tonne CO_2e/year. Whether it is through displacement of existing coal to methanol facilities or by causing companies to cancel planned new coal to methanol facilities, the introduction of KMMEF methanol into the MTO market will drive substantial GHG reductions in the global methanol market compared to exisiting conditions or future growth based on CTM.

[1] The focus of this Executive Summary is parameters impacted by the displacement effects analysis as they drive the results of a comprehensive review of project impacts. Additional end use emissions (emissions from the manufacture of olefins from the methanol) are also discussed in the Study for general information purposes (see, e.g., Sections 4 and 5) but are not included in the tables here as they do not change the conclusions on net impacts. The olefins manufacturing process would produce the same GHG emissions, regardless of methanol feedstock.

1. INTRODUCTION

Northwest Innovation Works, LLC – Kalama (NWIW) and the Port of Kalama (the Port) are proposing to construct and operate the Kalama Manufacturing and Marine Export Facility (KMMEF or the Facility) natural-gas-to-methanol production plant and storage facilities on approximately 90 acres at the Port in unincorporated Cowlitz County, Washington (Figure 1.1). The Northport site is on the east bank of the Columbia River and both the Burlington Northern Santa Fe (BNSF) Railway and Interstate 5 (I-5) lie immediately to the east.

To assess the impacts of the project on greenhouse gas (GHG) emissions and climate change, Life Cycle Associates, LLC was contracted to complete a life cycle analysis of the GHG emissions (this Study) to examine the direct and indirect emission impacts of the KMMEF. This Study addresses the following sources of GHG emissions: 1) GHG emissions attributable to construction of the project; (2) onsite direct GHG emissions from the project; (3) GHG emissions from purchased power, including consideration of the potential sources of generation that would satisfy the new power needs; (4) GHG emissions potentially attributable to the project from natural gas production, collection, processing and transmission; (5) GHG emissions from the shipping of methanol product to a representative Asian port (The representative Chinese port is Bohai Chemicals Marine Terminal in Tianjin China. There are several MTO facilities in operation and planned adjacent to Bohai Tianjin China and the port is also approximately an equal distance to other major productions centers in eastern China); and (6) GHG emissions associated with changes in the methanol industry and related markets that may be induced by the Project's methanol production. This Study discusses the intended use of KMMEF methanol as a feedstock for olefin production as well as comparing the KMMEF and alternative feedstocks and their relative olefin production emissions. This Study also considers the potential for the project to contribute to market changes that could affect the use of methanol generally as fuel.

This Study does not address other forms of air pollutants which were addressed in detail in the Final Environmental Impact Statement (FEIS) completed for the KMMEF.

1.1 Project Description

The proposed KMMEF would be operated by NWIW and at full capacity would produce up to 10,000 metric tons (tonnes) of methanol per day. The methanol would be stored on site for shipment to global markets by ship from a newly constructed dock. The Facility will be constructed with two production lines constructed in two phases, each with a daily production capacity of 5,000 tonnes. The anticipated annual production capacity with both production lines would be approximately 3.6 million tonnes. This Study is based on the plant operating with both production lines in operation.

The Facility would process natural gas from a pipeline to be constructed for this project that would be approximately 3.1 miles of 24-inch diameter pipeline, and include metering facilities and miscellaneous equipment, extending from Northwest Pipeline's (NWP) mainline located east of the Northport site to the proposed facility.

Methanol would be manufactured at the Facility by removing impurities from natural gas, converting the purified feedstock gas into synthesis gas which is converted into crude methanol. The crude methanol is distilled into a liquid methanol product which is stored on site until it is loaded onto marine vessels for export at the proposed marine terminal. At full operation, approximately 3 to 6 ships per month would be loaded at the Facility. The methanol is expected to be used in Asia[2] for the production of olefins[3] (methanol to olefin or MTO), which are the primary components in the production of consumer products, such as medical devices, glasses, contact lenses, recreational equipment, clothing, cell phones, furniture, and many other products.

Figure 1.1. Kalama Methanol Facility.

1.2 No Action Alternative

If the project is not constructed, the site may be developed for other uses as it is expected that the Port would pursue future industrial or marine terminal development of the site absent the proposed project. Given the demand for methanol in global markets, additional methanol production facilities may be constructed on another site within the Pacific Northwest or at other locations in the world or existing production facilities could maintain or expand production. Feedstock could consist of natural gas or other feedstock, such as coal. This Study will not evaluate other alternatives that could be constructed at the project site but will assess

[2] Bohai Tianjin, China is the representative Marine Port and MTO facility that will receive KMMEF manufactured methanol.
[3] Olefins include products like ethylene, propylene, and butylene.

the market implications of not constructing the project including sourcing methanol from other production to serve the anticipated markets.

1.3 Greenhouse Gases and Climate Change

1.3.1 The Greenhouse Effect

The greenhouse effect is a natural process that results in warmer temperatures on the surface of the earth than that which would occur without it. The effect is due to concentrations of certain gases in the atmosphere that trap heat as infrared radiation from the earth is reradiated back to outer space. The greenhouse effect is essential to the survival of most life on earth, by keeping some of the sun's warmth from reflecting back into space and sustaining temperature that make the Earth livable (Myhre et al., 2013).

1.3.2 Greenhouse Gases

The gases emitted globally that contribute to the greenhouse effect are known as greenhouse gases (or GHGs). Primary GHGs include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and other trace gases. Natural sources of GHGs include biological and geological sources such as plant and animal respiration, forest fires and volcanoes. However, industrial sources of GHGs are the primary concern. The GHGs of primary importance are CO_2, CH_4, and N_2O because they represent the majority of the GHGs emitted by industry. Because CO_2 is the most abundant of these gases, GHGs are usually quantified in terms of CO_2 equivalent (CO_2e), based on the relative longevity in the atmosphere and the related global warming potential (GWP).

Global Warming Potential

GWP is a measure of the potential of a gas to have an effect that could lead to climate change due to prolonged residence time in the atmosphere. The GWP can be used to quantify and communicate the relative and absolute contributions to climate change of emissions of different GHGs (Myhre et al., 2013) and of emissions from countries or sources.
Table 1.1 shows the GWP values from the Intergovernmental Panel on Climate Change (IPCC), an international body founded by the United Nations for the 100 year and 20-year time horizons from the two latest IPCC Assessment Reports, (AR4 and AR 5), about the state of scientific, technical and socio-economic knowledge on climate change.

Table 1.1. Global Warming Potential of GHG Pollutants

IPCC Assessment	AR5[a]		AR4	
GWP Time Horizon	100	20	100	20
CO_2	1	1	1	1
CH_4	30[a]	85	25[a]	72
N_2O	265	264	298	289

[a] IPCC Fifth Assessment Report 5 (AR5) published in 2014 includes a GWP of 28 for biogenic CH_4. Since the biogenic source would be emitted either as CO_2 or CH_4, the difference between the GWP of 30 and 28 represents in the indirect effects of methane decomposition to CO_2. (Myhre, 2013)
[b] Fourth IPCC Assessment report published in 2007

The United Nations Framework Convention on Climate Change uses the 100-year GWP. The United States primarily uses the 100-year GWP for reporting of GHG emissions. The State of Washington Greenhouse Gas Reporting program (Section 173-441 of the Washington Administrative Code) also uses the 100-year GWP. The 20-year GWP is sometimes used as an alternative to the 100-year GWP. The 20-year GWP prioritizes gases with shorter lifetimes, because it does not consider impacts that happen more than 20 years after the emissions occur. Because all GWPs are calculated relative to CO_2, emission calculations based on a 20-year GWP will be larger for gases with lifetimes shorter than that of CO_2, and smaller for gases with lifetimes longer than CO_2 (EPA). Values in this Study are based on the AR4 100-year GWP for consistency with International, United State and Washington reporting requirements.

1.3.3 Climate Change

The phenomena of natural and human-caused effects on the atmosphere that cause changes in long-term meteorological patterns due to global warming and other factors is generally referred to as climate change. The global climate changes continuously, as evidenced by repeated episodes of warming and cooling documented in the geologic record. But the rate of change has typically been incremental, with warming or cooling trends occurring over the course of thousands of years. The past 10,000 years have been marked by a period of incremental warming, as glaciers have steadily retreated across the globe. However, scientists have observed an unprecedented increase in the rate of warming over the past 150 years. This recent warming has coincided with the Industrial Revolution, which resulted in widespread deforestation to accommodate development and agriculture along with increasing use of fossil fuels. These changes in land uses and consumption of carbon-laden fuels have resulted in the release of substantial quantities of greenhouse gases – to the extent that atmospheric concentrations have reached levels unprecedented in the modern geologic record.

The accumulation of GHGs in the atmosphere affects the earth's temperature. While research has shown that the Earth's climate has natural warming and cooling cycles, the overwhelming preponderance of evidence indicates that emissions related to human activities have elevated the concentration of GHGs in the atmosphere far beyond the level of naturally- occurring concentrations and that this in turn is resulting in more heat being held within the atmosphere. The IPCC has concluded that it is "very likely" – representing a probability of greater than 90 percent – that human activities and fossil fuels, commonly referred to as anthropogenic emissions, explain most of the warming over the past 50 years, (IPCC, 2007).

The IPCC predicts that under current human GHG emission trends, the following results could be realized within the next 100 years (IPCC, 2007):

- global temperature increases between 1.1 to 6.4 degrees Celsius
- potential sea level rise between 18 to 59 centimeters or 7 to 22 inches
- reduction in snow cover and sea ice
- potential for more intense and frequent heat waves, tropical cycles and heavy precipitation, and
- impacts to biodiversity, drinking water and food supplies

The Climate Impacts Group (CIG) is a Washington State based interdisciplinary research group that collaborates with federal, state, local, tribal, and private agencies, organizations, and businesses, and studies impacts of natural climate variability and global climate change on the Pacific Northwest. CIG research and modeling indicates the following possible impacts of human-based climate change in the Pacific Northwest (Climate Impacts Group University of Washington, 2013):

- changes in water resources, such as decreased snowpack, earlier snowmelt, decreased water for irrigation, fish and summertime hydropower production, increased conflicts over water, and increased urban demand for water
- changes in salmon migration and reproduction
- changes in forest growth and species diversity and increases in forest fires, and
- changes along coasts, such as increased coastal erosion and beach loss due to rising sea levels, increased landslides due to increased winter rainfall, permanent inundation in some areas, and increased coastal flooding due to sea level rise and increased winter stream flows

GHGs effect climate change in the same manner irrespective of the location of emissions and the impacts on climate are felt globally. Emissions from Cowlitz County have the same affects as those from any other location. While general consensus is that anthropogenic GHG emissions are a cause of climate change it is the cumulative effect of all emission sources in the atmosphere rather than individual sources that is the cause. It is not generally possible to equate a specific climate change response to a specific emissions source from an individual project.

1.4 Goal and Scope Definition

The goal of this Study is to inform the SEIS for the KMMEF and provide an assessment of the direct, indirect, and displaced emissions from methanol production.

1.4.1 Analysis Scope

The goal of the Study is to provide the technical analysis in support of the Supplemental Environmental Impact Statement (SEIS) being prepared by the Port and Cowlitz County (County) under the Washington State Environmental Policy Act (SEPA). The Port and County completed the scoping process for the SEIS and determined that the scope includes the quantification of GHG emissions from the following:

1. Emissions attributable to construction of the project;
2. Onsite direct GHG emissions from the project
3. Emissions from purchased power, including consideration of the potential sources of generation that would satisfy the new load;
4. Emissions potentially attributable to the project from natural gas production, collection, processing and transmission;
5. Emissions from the shipping of methanol product to a representative Asian port; and
6. Emissions associated with changes in the methanol industry and related markets that may be induced by the project's methanol production. The SEIS would also clarify the intended use of methanol produced by KMMEF as a feedstock for olefin production and will also consider the potential for the project to contribute to market changes that could affect the use of methanol generally as a fuel. The SEIS will also identify any substantial changes to project design and engineering since publication of the FEIS and will evaluate whether these changes would affect any analysis of conclusions set forth in the FEIS.

1.5 Life Cycle Assessment Background

Since the effect of GHG emissions occur over a long duration, the life cycle and total global emissions are considered the relevant metric[4]. Life Cycle Assessment (LCA) is a technique used to model the environmental impacts associated with the production of a good. LCA models can assess environmental impacts over a range of categories, including GHG emissions as well as others. This is done by taking a full inventory of all the inputs and outputs involved in a product's life cycle. This Study takes an LCA approach to identifying GHG emissions for the Facility.

Upstream emission are calculated on a life cycle basis to enable the calculation of cradle to grave emissions in combination with direct or end use emissions, which is consistent with the ISO 14040 methodology (ISO, 2006). The upstream life cycle emissions correspond to the Scope 2 and Scope 3 emissions that are part of statewide inventory reporting (World Resources Institute, 2004). These emissions are often referred to as indirect emissions in environmental impact studies. An LCA is typically designed to compare one system with a reference system that achieves the same functional unit. Typically, two systems are compared until to the extent that the same functional unit is achieved. The scope of analysis for this Study includes the upstream life cycle, direct, and downstream transport emissions. Upon delivery, the functional unit is the same as other sources of methanol.

Most LCA tools are spreadsheet or database models that use life cycle inventory ("LCI") data to calculate the environmental impacts associated with the material flows and inputs.

[4] For example, consider electric cars with zero emissions during driving. The life cycle emissions including upstream emissions provide the relevant basis for comparison with other transportation options.

Additionally, LCA has been used to support regulatory and/or legislative initiatives for renewable targets, such as targets for GHG emission reductions. This Study follows the process for Life Cycle Assessment defined by international standards shown in Figure 1.2.

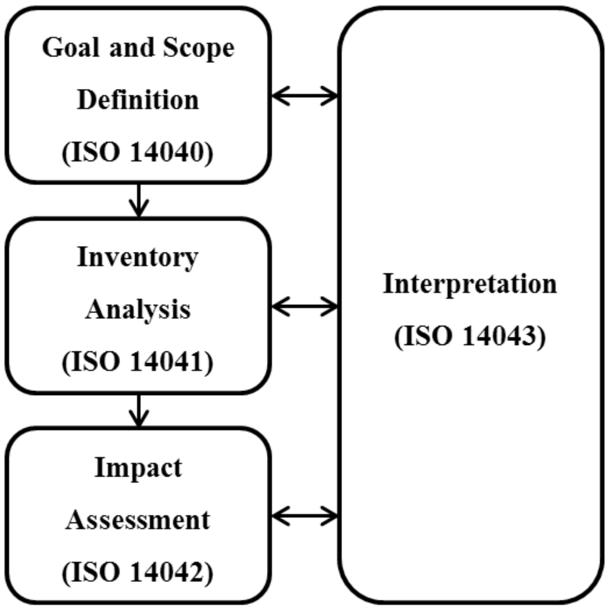

Figure 1.2. Process Framework for Life Cycle Assessment
Source: (ISO, 2006)

Life cycle emissions are generally considered to cover the full life cycle from resource extraction to end use. Life cycle assessments are generally limited to the construction and operation periods. An LCA includes the upstream emissions for inputs to a process. In most cases, upstream emissions occur in the production of upstream inputs. For example, producing the natural gas used for generation of electric power on site requires upstream energy inputs. Upstream energy inputs like this are accounted for in this Study.

The boundaries of life cycle emissions typically expand beyond the regional scope of a State such as Washington, for example. The production of feedstocks and materials can occur outside the state even if facility operations occur in the state. Global life cycle emissions represent an appropriate metric for GHG emissions because of the long-lasting effect of the pollutants; however, emissions that occur in the State of Washington are of interest due to the State's efforts to manage its GHG emissions, particularly for addressing in-state GHG emissions against state reduction targets.

Determining life cycle emissions for all of the project related inputs requires an iterative analysis of these components. Several LCA models have been developed to perform these calculations for fuels and materials as shown in Table 1.2. All the models include life cycle data for various products, including methanol. Fuel LCA models provide upstream emissions for all the energy inputs considered in this analysis which include natural gas, electric power, diesel fuel, and marine fuel. These models also contain an upstream life cycle analysis for generic natural gas and coal-based methanol and are publicly available.

Table 1.2. Life Cycle Models and Databases

Year	Organization	Location of Use	Scope of Products	Model/ Database	Citation
2017 2013	ANL	USA	Fuel Vehicles	GREET1 GREET2	(ANL, 2017b)
2016	(S&T)2	Canada	Fuels	GHGenius	((S&T)2, 2013b)
1998	UC Davis	USA	Fuels	LEM	(Delucchi, 2003)
2011	JRC	Europe	Fuels	JRC/ LBST Database	(Edwards, Larivé, Rickeard, & Weindorf, 2013)
2012	Intelligent Energy Europe	Europe	Fuels	BioGrace	(JRC, 2012)
2016	ThinkStep	Global	All Materials	GaBi TS	(Thinkstep, 2017)
2013	Swiss Centre for Life Cycle Inventories.	Global	All Materials	EcoInvent	(Weidema et al., 2013)
2005	NREL	USA	All Materials	USLCI Database	(NREL, 2012)
2014	NETL	USA	Fuels	Studies of NG and Coal	(Skone, 2012)

Several studies have shown that LCA models perform similar calculations and that differences in model results are primarily due to allocation methods and input data including regionally specific detail ((S&T)2, 2013a; Unnasch & Riffel, 2015). The GREET and GHGenius models provide the basis for upstream life cycle data in this study because the inputs are readily modified for different scenarios. The models are also available to the public. Even though GREET and GHGenius were developed for transportation, they provide the same level or greater detail as other LCA models and the models and documentation are available to the public. In addition, the inputs for parameters such as CH_4 leakage are direct model inputs with corresponding effects on the full life cycle of natural gas, coal, and electric power. Therefore, the GREET and GHGenius models were selected to provide the basis for upstream life cycle emissions.

Several LCA models and databases also include LCI data on materials of construction for methanol facilities. The GaBi TS, EcoInvent, and USLCI databases contain life cycle analysis results for materials such as steel and concrete, which are used in facility construction. The GREET2 model also calculates life cycle emissions for materials of construction used in vehicles.

The GREET and GHGenius models are publicly available and provide complete transparency to calculations. Both models are widely used in Canada and the United States. These models provide the basis for upstream life cycle inventory (LCI) data for this Study.

1.6 Study Contents

This Study examines the effect of KMMEF methanol on global GHG emissions. The Study includes the following Sections.

1. Introduction
2. Methods and Data
3. KMMEF Emissions
4. Market Effect and Economic Analysis
5. Displaced Emissions
6. Life Cycle Assessment
7. Conclusions

Section 1 provides an introduction to the KMMEF, GHG emissions, and LCA. The methods and data used in the Study are described in Section 2, which includes a description of upstream fuel cycle inputs as well as the energy inputs and yields for methanol production and other data. Section 3 combines the data in Section 2 applied with inputs for KMMEF to determine construction and operation emissions. Section 4 provides an economic analysis of the supply and demand for methanol in China. This analysis provides the basis for determining the methanol that is displaced by the KMMEF output. Section 5 details the emissions avoided due to the displacement of other sources of methanol. It combines the data from Section 2 with energy inputs and yields for alternative methanol production sources identified in Section 4. Section 6 presents the total life cycle emissions from KMMEF with the emissions from displaced methanol production and evaluates uncertainty in the analysis. Section 7 summarizes the conclusions of the Study.

2. METHODS AND DATA

This Study examines the GHG emissions on a life cycle basis. The emissions from the KMMEF are compared to the GHG emissions from alternative sources of methanol production. A no action scenario where the project is not built is also analyzed. This section describes the system boundary for the analysis, approach for calculating life cycle emissions, scenarios considered in the Study, and data sources. The discussion of the approach describes a summary of the activity in each step of the life cycle and calculation methods. Since many of the data sources are common among life cycle stages, the discussion is grouped according to the type of emissions that occur.

2.1 System Boundary

The analysis of GHG emissions for the KMMEF includes emissions associated with feedstock production and transportation, the production of power, the direct emissions from the KMMEF and the delivery of the product to an Asian port. An additional comparison of KMMEF methanol and alternative feedstocks with their relative olefin production emissions is presented in Section 5.4.

The analysis is performed on a life cycle basis. Upstream emissions include natural gas feedstock extraction, processing and transmission as well as imported grid power. Direct emissions from the KMMEF include combustion emissions from construction activities, boilers, power generation, and fugitive emissions. Downstream emissions consist of transport and distribution emissions from marine vessels delivering methanol to an Asian port and return of the empty vessels to KMMEF. Indirect[5] emissions associated with construction materials, fuel production and marine diesel are also counted. The same scope of emissions is applied to the displaced methanol.

The system boundary for KMMEF methanol is shown in Figure 2.1. The displacement of methanol or other displacement effects is determined through an economic analysis (Section 4).

[5] Indirect emissions include upstream life cycle emissions as well as other emission effects that occur outside of the KMMEF. These Scope 2 and Scope 3 (World Resources Institute, 2004) emissions are referred to as upstream life cycle emissions to be consistent with the terminology used in LCA studies.

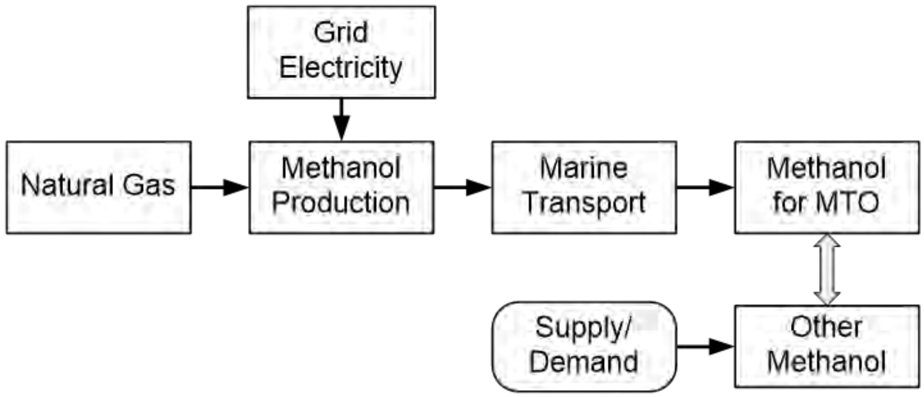

Figure 2.1. System Boundary Diagram for KMMEF Life Cycle Assessment.[6]

Functional Unit

The functional unit for the Study is the methanol produced in one year of continuous operation. The life cycle emissions from the KMMEF and displaced emissions are analyzed over this functional unit. The emissions are also reported per tonne of methanol delivered to Bohai Tianjin, China.

Life Cycle Criteria

The Study determines the GHG emissions from fuel combustion[7] and fugitive emissions including CO_2, CH_4, and N_2O. Other GHG emission sources include unburned and fugitive methane and nitrous oxide (N_2O) from fuel combustion. As discussed in Section 1.3.2, CO_2 emissions correspond to fully oxidized fuel. These emissions also include fugitive methanol from storage tanks and product transfers as well as carbon monoxide and VOC emissions from fuel combustion. Other GHG emissions such as fluorocarbons are not a significant source of emissions from KMMEF.

<u>Analysis period</u>

Emissions are calculated based on the amount of methanol produced in one year of continuous operation with a capacity of 10,000 tonnes per day of methanol production for 365 days per year. In addition, emissions are also reported per tonne of methanol delivered to Bohai Tianjin, China.

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[6] The complete indirect effect of KMMEF methanol includes emissions from MTO. The emissions from MTO are identical for other sources of methanol. Emissions from further potential indirect effects are examined in Section 5.4.

[7] Combustion sources include boilers, fired heaters, power generation equipment and engines for transport. Feedstock is also converted to CO_2 in the methanol production process and these process emissions are also counted.

Cut Off Criteria

This LCA tracks GHG emissions based on life cycle models. Emissions that are less than 1% of the life cycle GHG emissions from the KMMEF plus upstream and downstream are under the threshold of significance and not examined as emission categories[8] (See Appendix A which examines the extent of excluded inputs. Most of the identified items are well below the 1% threshold).

2.2 Activities and Approach to GHG Analysis

The GHG analysis encompasses the emissions associated with KMMEF construction and operation and the alternative to not completing the project, which would be the life cycle effect of not shipping methanol to Bohai Tianjin, China from KMMEF. The life cycle steps and description of the activities for each step are shown in Table 2.1.

Table 2.1. Grouping of Life Cycle Steps

Life Cycle Step	Description
Construction	Construction equipment, dredging, materials of construction Fuel and power production
KMMEF Upstream	Natural gas feedstock extraction, processing and transmission, electric power production
KMMEF Operation	Boiler, natural gas power plant, methanol plant operation
KMMEF Downstream	Methanol transport, diesel fuel production
Alternative Upstream	Coal, power, diesel fuel production
Alternative Operation	Coal and natural gas methanol plant operation
Alternative Downstream	Methanol transport, diesel production
Life Cycle Assessment	Comparison of KMMEF to Alternative

2.2.1 Life Cycle Analysis

Life cycle emissions generally consist of direct and upstream life cycle emissions. Argonne National Laboratory's GREET (Argonne National Laboratory, 2009) model has been extensively used for quantification of life cycle emissions associated with fuels and other products. This Study uses the GREET framework to calculate emission rates from cradle to gate (ANL, 2017b)[9].

Each step in the life cycle includes direct and upstream life cycle emission rates ($\mathbf{E}_u$). Upstream life cycle emission rates include a variety of energy inputs and emissions including natural gas,

[8] Calculations in this Study are shown to full precision to the left of the decimal to minimize rounding errors in tables. Numbers that are less than one and not significant to the study results are shown to a level of precision that identifies the order of magnitude of the value.

[9] Cradle to gate emissions are also referred to as well to tank or upstream life cycle. The term upstream life cycle is used in this Study. Fuel life cycle emissions are referred to as cradle to grave or well to wheels (or wake). The end use for alternative methanol is the same as that for KMMEF methanol. A comparison of end use emissions is discussed in Section 5.3.

petroleum fuels, and electric power. Emission rates (**E**$_i$) for each step in the life cycle are calculated from the specific energy (S_k), direct emission factor (**EF**$_k$), and upstream emission rates for the step such that:

$$\mathbf{E}_i = \sum\left[S_k \times (\mathbf{EF}_k + \mathbf{E}_{uk})\right] \tag{1}$$

Where:
E$_i$ = Life Cycle Emission rate for Step i
EF$_k$ = Emission Factor for fuel k, for each type of equipment and fuel
S_k = Specific Energy for each fuel k
E$_{uk}$ = Upstream life cycle emission rate for fuel k

Typically, GHG calculations are tracked on a specific energy basis[10]. For example, the term S_k for natural gas use is represented in mmBtu/tonne of methanol in this Study. The emission factor (**EF**) depends upon the carbon content of fuel as well as CH_4 and N_2O emissions for the type of equipment. For electric power and construction materials, the term EF is zero but upstream emissions are calculated using the same principles. The terms **EF** and **E** represent a data array that includes CO_2, CH_4 and N_2O emissions.

Upstream life cycle emission rate (**E**$_u$) depend on the energy inputs and emissions for each fuel or material and are calculated in the same manner as shown in Equation 1. Upstream emissions for this Study are calculated using the GREET model with inputs described in Section 2.4.

The life cycle analysis of KMMEF methanol follows the steps outlined in Table 2.1. For each step, the emissions include direct plus upstream emissions.

A detailed discussion of the calculations and upstream life cycle approach is described in Appendix A.

Construction Emissions

Construction activities consist of development of the KMMEF site, construction of the methanol plant, storage tanks, the power plant, and dredging at the site. Construction activities include operation of earth moving equipment, cranes, trucks, pile drivers, compressors, pumps, and other equipment. Employee commute traffic and material transport also generates GHG emissions.

Upstream Natural Gas

Natural gas produced in Canada will be the feedstock for the KMMEF. The gas is transmitted through NWP's interstate pipeline system. NWIW will contract with natural gas suppliers that

[10] GREET inputs are typically in Btu/mmBtu. However, the calculations are the same for a functional unit of one tonne of methanol with the appropriate unit conversions. The nomenclature here assumes appropriate unit conversions.

purchase natural gas from Canadian producers. This purchase will result in the delivery of natural gas to pipelines in Canada and the Pacific Northwest.

Figure 2.2 shows the system boundary diagram for natural gas extraction, processing and transmission in the GREET model. The model calculates upstream emissions from natural gas pathways including methanol and compressed natural gas as well as fuel for applications such as power plants and oil refineries. Emissions from natural gas extraction and processing are split between natural gas and natural gas liquids. The allocation of these emissions is an external input to the GREET and GHGenius models.

GREET inputs are energy inputs and fugitive CH_4 for each step in the life cycle as described in Section 2.4.2.

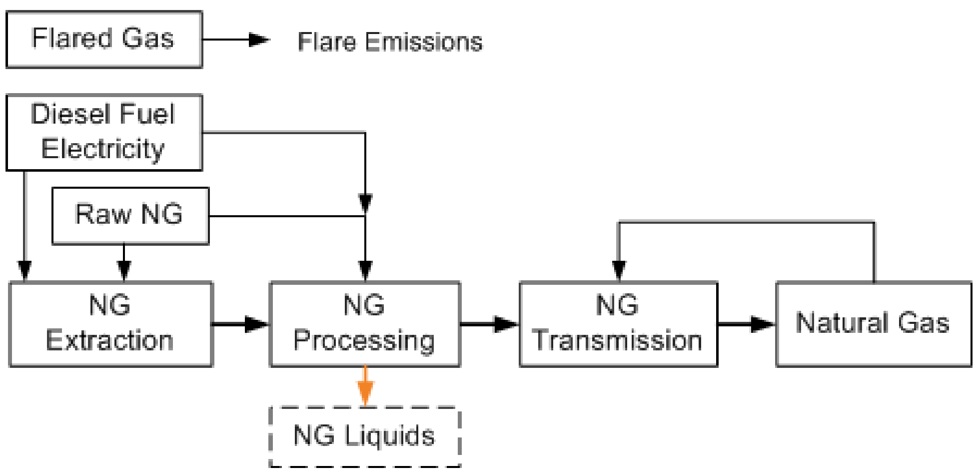

Figure 2.2. Natural Gas Production System Boundary Diagram

Power Generation

Emissions from power generation include emissions for natural gas turbines and boilers, coal boilers as well as upstream inputs for fossil fuels and uranium for nuclear power plants. The system boundary for electric power in Figure 2.3 includes the upstream activities of each fuel used to produce electricity, direct combustion of these fuels at the power generation facility, and losses through the transmission and distribution system. This Study examines a range of power resource mixes described in Section 2.4.4. The inputs to the GREET model are the resource mix with GREET model inputs for power generation. Power generation efficiency and transmission loss are also GREET inputs and are not modified for this Study. The GREET results for direct combustion emissions are consistent with eGRID values[11].

[11] GREET calculates both power plant emissions and upstream fuel cycle emissions for power plant fuels. The GREET results for power plant emissions will match eGRID if the resource mix and generation efficiency comparable. Note that eGRID emissions alone do not include the upstream fuel cycle component.

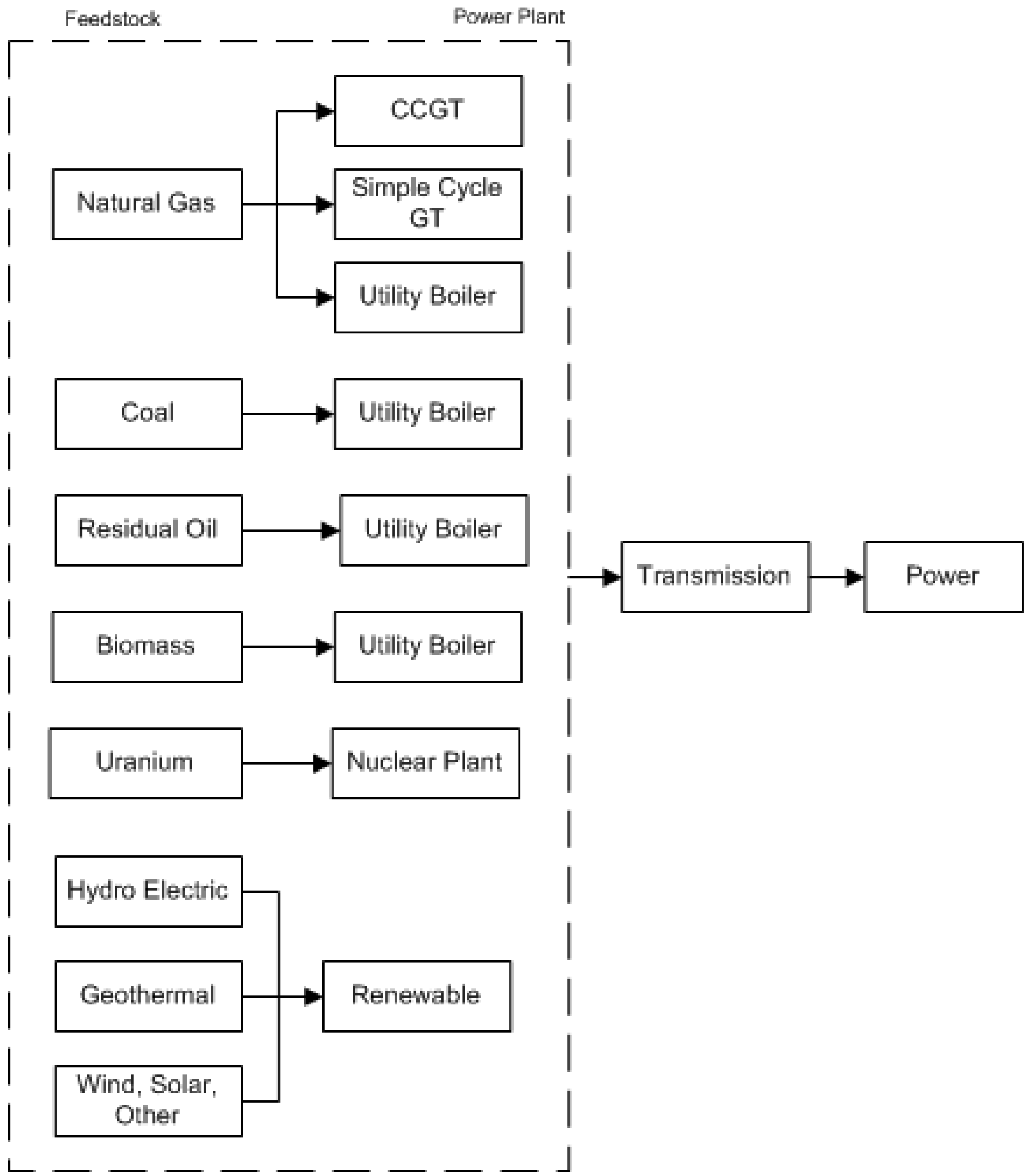

Figure 2.3. Electricity Production System Boundary Diagram

Direct Facility Emissions

Direct operating emissions from KMMEF include the sources shown in Figure 2.4. Natural gas is converted to methanol with some unconverted byproduct gas burned in a boiler along with natural gas. Natural gas also provides fuel for a natural gas combined cycle power plant. A small quantity of natural gas is also combusted in a flare pilot. Fugitive emissions also occur from the methanol system and storage tanks.

Net CO_2 emissions for the KMMEF (C_K) are verified by carbon balance such that the carbon in each of the components balance. Net carbon emissions (C_K) are calculated such that:

$$C_K = C_{NGT} - C_{MeOH} \quad (2)$$

Where:

C_K = Carbon emissions from KMMEF
C_{NGT} = carbon in natural gas feedstock
C_{MeOH} = Carbon in methanol

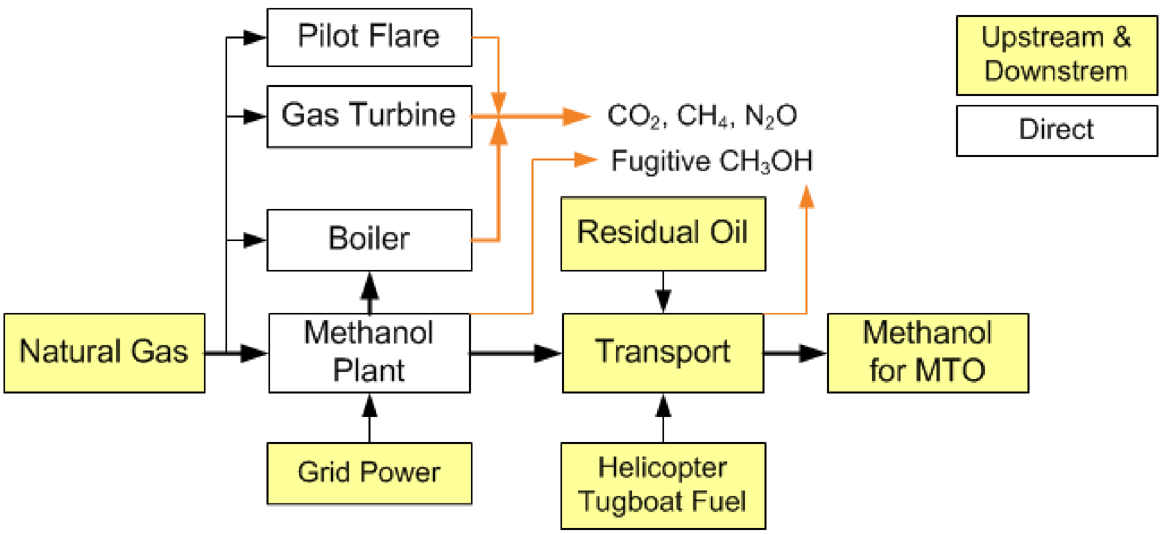

Figure 2.4. Direct Emissions Sources from KMMEF.

Downstream Operational Emissions

Downstream emissions for KMMEF include the transport of methanol from Kalama to Bohai Tianjin, China. Emissions correspond to the combustion of fuels for 50,000 to 100,000 tonne capacity marine vessels.

For each transport segment the transport emissions correspond to the sum of transport segments based on the transport distance and energy intensity. The emission factors correspond to either residual oil or diesel fuel. GHG emissions correspond to the fuel used combined with the emission factor in Appendix C for each fuel.

Upstream Life Cycle Emissions associated with the production of Petroleum Products

Petroleum products are used for methanol transport, small quantities of on-site diesel, and transport of feedstock for displaced methanol. The upstream life cycle emissions associated with this petroleum product use include crude oil extraction, transport, oil refining, and delivery of the petroleum product.

Petroleum fuels are used in the transport of methanol to Bohai Tianjin China, fuel for equipment during KMMEF construction as well as the production and transport of coal, and delivery of methanol by truck in China for the coal alternative.

Crude oil is produced and transported from a variety of resources and regions in the world. In some cases, crude oil production results in the production of associated gas and the cogeneration of electric power. Crude oil is transported to oil refineries and refined into a range of products shown in Figure 2.5. GHG emissions from petroleum production depend on the crude oil type and the extraction method as well as oil refinery configuration with about a 10% range in life cycle emissions from different crude oil types (Gordon, Brandt, Bergerson, & Koomey, 2015; Keesom, Blieszner, & Unnasch, 2012). The life cycle analysis of petroleum production in the GREET model takes into account the upstream emissions for crude oil production as well as the energy intensity to refine different products. The GREET inputs for petroleum product refining are based on a linear programming analysis of U.S. refineries (Elgowainy et al., 2014). The energy inputs and emissions within oil refineries are allocated with this approach between diesel, gasoline, residual oil, LPG, naphtha, and coke. The GREET modeling approach assigns greater energy inputs to gasoline and diesel fuels and less to residual oil and naphtha since refinery units are designed to produce diesel and gasoline.

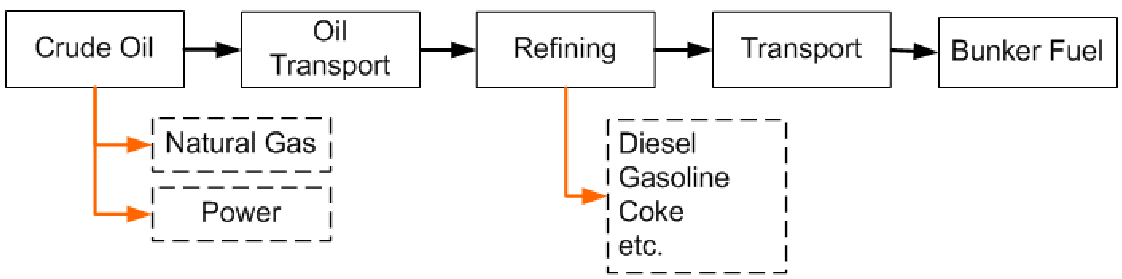

Figure 2.5. System Boundary Diagram for Petroleum Products.

The upstream data for refined petroleum products used for methanol transport are shown in Section 2.4.7.

2.2.2 Displaced Emissions

The life cycle GHG emissions from KMMEF methanol are compared to the alternative of not completing the KMMEF. The source of displaced methanol is determined by assessing the supply and demand for methanol to Eastern China. GHG emissions are then calculated based on the energy inputs and transport distance for methanol plants that are displaced. Key trends are considered such as the new methanol units planned in the U.S. Gulf Coast taking advantage of economical and abundant shale gas. These planned capacity additions represent a rebuilding of the methanol production capability that was nearly all shut down during the last decade due to high feedstock costs. New and planned coal to methanol capacity in China are also examined.

The Study estimates costs based on technology, estimated feedstock cost and yield, utility consumption and other variable and fixed plant costs. Plant size, degree of integration and

operational capacity are all considered. Cost of delivery from major producing regions to major consuming regions, including transport, is included to generate delivered cost curves.
(See Section 4.5.1)

The supply curve is the tool that economists use to characterize markets. Markets include production plants that have developed over time, utilize different processes, and applied different feedstocks. To develop a supply curve for methanol, we need to know the location, cash cost, capacity and normal operating fraction for all methanol plants in the world. Some methanol production may be excluded as the production facility is integrated into a production complex that uses the methanol produced as an integrated input to another final or intermediate product such as formaldehyde or olefins. This methanol production is not offered for sale in the merchant market. An inventory of global methanol plants provides the basis for determining the leading suppliers to China.

Production Costs

Production costs provide the basis for developing a global methanol supply curve. The basis for cost ranking is cash cost of production plus transport cost to Bohai Tianjin, China. Production costs include feedstock based on feedstock to methanol efficiency plus operating cost. Operating cost estimates are developed as a function of plant capacity and aligned with estimates from cost studies. Feedstock inputs provide the basis for estimating GHG emissions. Furthermore, the ranking of methanol plants on the supply curve identifies the marginal GHG emissions. The ranking on the supply curve depends on the following factors:

- Feedstock cost
- Feedstock and power to methanol efficiency
- Operating cost as a function of plant capacity and technology
- Transport mode and distance to Bohai Tianjin, China

The cash cost of methanol is calculated via the following

$$C_M = S_f \times C_f + C_{O\&M}(M) + C_T(D) \quad (3)$$

Where:

C_M = Cash cost of methanol
S_f = Specific energy of feedstock consumption (Btu or tonne/tonne of methanol)
C_f = Cost of feedstock ($/mmBtu or $/tonne)
$C_{O\&M}(M)$ = Operation and maintenance costs as a function of plant capacity, M
$C_T(D)$ = Transport cost as a function of transport mode and distance D

Data that support the production cost analysis include feedstock to methanol yields in Section 2.4.1, feedstock and plant operating costs in Section 2.4.8, and transport distances in Section 2.4.6.

Developing a Supply Curve

The growing demand for methanol has supported the expansion of methanol production capacity for many years. With new sources of low cost natural gas becoming available and the continued expansion of methanol uses, investments in expanding existing methanol plants and in developing new plants have been growing for the past decade and are expected to continue to grow based on forecasts from ASIACHEM, IHS and other sources.

The identification of the specific methanol plants that provide production is based on the current market feedstock price and the cash (marginal) cost of production at each plant. Figure 2.6 provides a general depiction of a supply structure for a hypothetical industry with four plants. The cash cost is on the “Y” axis and demand is on the “X” axis. Each plant blue rectangle is the height of its cash cost and the width of its operating capacity, the amount that plant can provide to the market. The lowest cost plant is on the left with each subsequently higher cost plant to the right providing its operating capacity. The horizontal red line is the current market price. Producers are willing to accept this price when it is above its cash cost. Plants 1 and 2 are able to sell all of their output at the market price and earn a positive margin. Plant 3 is willing to produce product at the market price, but not all of its operating capacity is needed to meet demand. Plant 4 is not willing to produce product as it is unable to recover its cash cost at the current market price. Plant 4 may or may not exist today but may represent a future investment in the anticipation that the market price will increase as the existing low-cost plants are unable to expand production to meet future demand at their current price. If, for example, Plant 2 is able to greatly expand its capacity at current cost, or if a new plant with similar cost to Plant 2 is built, Plant 3 may cut production or exit the market as it can no longer recover its cash cost as the market price will be reduced to the lower cash cost of the expanded capacity.

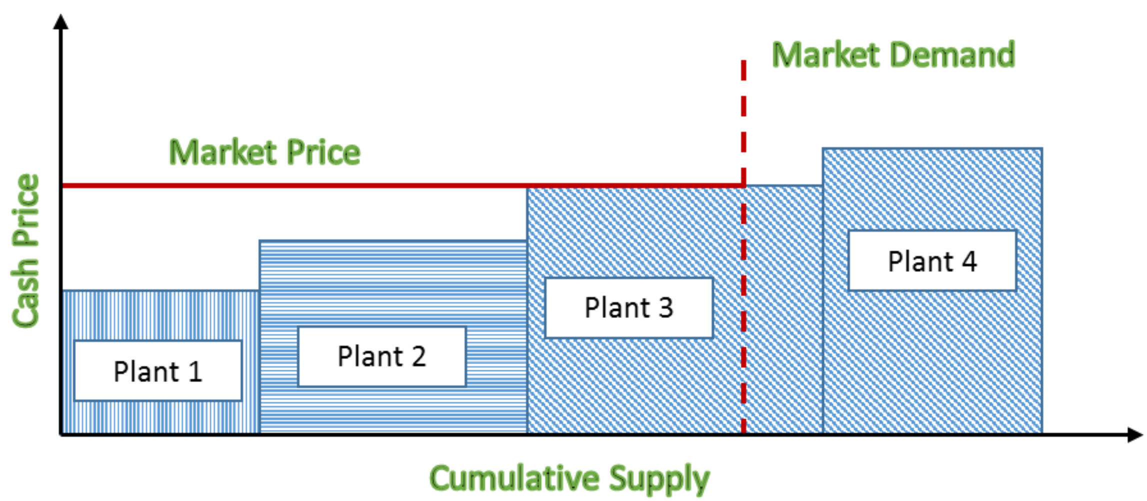

Figure 2.6. Generic Long Run Supply Curve.

Upstream Life Cycle of Coal Feedstock

If KMMEF is not constructed, global market demand for methanol will rely on other sources of methanol manufactured from other feedstocks. The primary alternative feedstock for methanol production is coal.[12]. Upstream emissions for coal production include the operating of mining equipment, coal mine methane, and coal transport. The life cycle of coal production is estimated in the GREET model for coal used in methanol plants. The GREET inputs are based on the energy intensity for China coal production. The upstream emissions for coal production correspond to energy inputs for mining and transport as well as methane emissions from coal mines. The upstream emissions for diesel and electric mining equipment are based on the system boundary diagram in Figure 2.7. Upstream emissions for coal feedstock were calculated using the GREET model for China specific coal production inputs. The default GREET inputs provide the basis for U.S. coal used in power generation as part of electricity mixes calculated for KMMEF.

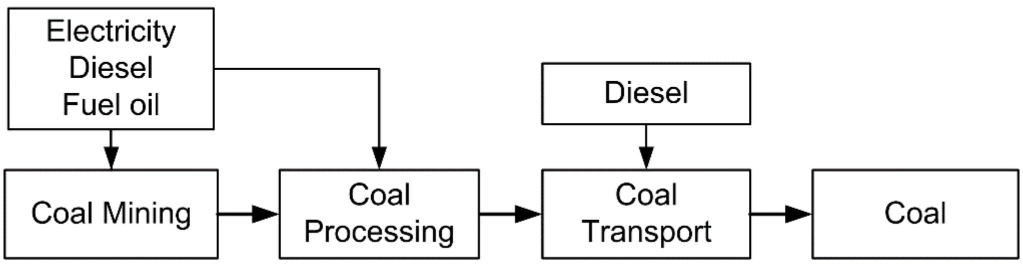

Figure 2.7. Coal Production System Boundary Diagram

Marginal GHG emissions are based on the shift in the supply curve as capacity from the KMMEF is added. The energy inputs and mix of feedstocks and transport distances for the facilities on the margin provide the basis for determining the long-run marginal source of methanol.

Alternative Methanol Transport

Alternative sources of methanol would be transported by truck or marine tanker. The calculation of GHG emissions is the same as those from marine vessels in Appendix A except that emission and energy use factors for diesel trucks and diesel production replace those for marine diesel operation.

2.3 Scenarios for GHG Impacts

KMMEF methanol production results in GHG emissions from facility operation, upstream and downstream emissions. The LCA analysis of GHG emissions from KMMEF also includes an assessment of the displacement of alternative sources of methanol. The factors that affect GHG emissions are discussed in the following section. Scenarios that evaluate a range of parameters are described in Section 2.3.2.

2.3.1 Key Parameters Affecting Life Cycle GHG Emissions

Table 2.2 shows the key parameters that affect GHG emissions, variability in these parameters, and effect on net GHG emissions. The energy inputs for the KMMEF are determined by the process design and performance guarantees. Therefore, the most significant variability in

[12] Section 4.5 identifies the marginal sources of methanol for China.

emissions is associated with the upstream natural gas and power generation. The capacity of marine transport vessels affects the energy use per tonne of methanol. Variability in feedstock production and power generation also affects displaced methanol. Finally, the displacement of methanol can affect the use of products globally.

Table 2.2. Key Parameters Affecting Life Cycle GHG Emissions.

Parameter	Effect on GHG Emissions
a. KMMEF Energy Inputs	Total natural gas input per tonne affects direct emissions from KMMEF. Upstream natural gas and imported electric power are proportional to the use rates.
b. Loss Factors	Fugitive methanol from storage and distribution requires the production of additional methanol to yield 1 tonne to the end user. The overall product loss is less than 0.01% and similar losses are incurred for alternative methanol production methods and the loss factor does not have a measureable effect on total emissions. (Appendix A.3).
c. Natural Gas Upstream	Leak rates from extraction, processing, and transmission represent about half of the upstream emissions from natural gas. Estimates vary depending on data sources.
d. Electric Power Generation	Electric power emissions depend on the generation mix. Several methods for assessing the generation mix were examined based on precedent with other government GHG analyses as well as constraints on the regional electricity grid.
e. Transport Mode	The energy intensity of methanol depends on the capacity of tanker ships. A range in tanker capacities is examined.
f. Displaced Methanol Production	Variability in the feedstock consumption is evaluated with a +/-5% range. The energy intensity of feedstocks and electric power for displaced methanol is also examined.
g. Market Effects on Demand	The market effect of KMMEF on world markets affects the demand for feedstocks as well as second order effects on methanol and olefins. The effect of methanol displacing fuel and MTO displacing olefins is examined in Sections 5.4 and 5.5. The market effects on feedstocks[a] are examined in Appendix F.2.

[a] For example, the alternative of producing 3.6 million tonnes per year of methanol from the KMMEF could result in the displacement of over 7 million tonnes per year of coal in China (See Section 2.4.1). Since coal is a global commodity, changes in the supply in China can affect coal prices and consumption globally. Such market mediated effects were analyzed by taking into account a coal market assessment (ICF International, 2017b). The coal market assessment takes into account coal supply curves for the U.S. and international coal supply regions, natural gas supply curves, and prevailing regulations.

2.3.2 Scenario Descriptions

GHG emissions are evaluated with four scenarios. The inputs represent a range of possible parameters regarding the inputs, transport logistics, and displacement effects. The Baseline scenario represents the study team's best estimate of input with conservative assumptions regarding power generation and KMMEF operation. The Lower emission scenario includes parameters that result in lower net emissions from the KMMEF and the Upper scenario includes parameters that lead to higher emission estimates. Market effects are also examined in a separate scenario, which falls within the range of the other three scenarios.

Baseline Scenario

The baseline scenario represents the central estimate among the key parameters. The operating conditions for the KMMEF reflect the start of run (SOR) condition, which consumes slightly more energy than the end of run (EOR) condition and is a conservative estimate ("run" refers to the life of the catalyst which is approximately 4 years). The upstream life cycle emissions of natural gas are based on a 99.4% British Columbia and 0.6% Rocky Mountain Gas, which corresponds to the 2016 mix of net deliveries described in Appendix B (EIA, 2018a).

Power generation emissions are based on the State of Washington mix; which results in conservatively higher GHG emissions than assuming the local Cowlitz PUD grid mix, which is the accounting method used for GHG reporting in Washington[13] and is described in Appendix B.

Displaced methanol producers are determined by the supply and demand analysis in Section 4. The energy inputs and feedstocks for displaced methanol correspond to the average of the marginal methanol producers as well as the average resource mix for feedstock and power production. Methanol for MTO displaces other sources of methanol. The overall emissions from MTO are described in Section 5.4.

Lower Emission Scenario

Several factors including the availability of renewable power could reduce the GHG footprint of the KMMEF. This scenario examines the effect of power demand from the KMMEF contributing to new loads of renewable power that will contribute to compliance with a renewable portfolio standard (RPS). The source of natural gas is based on 100% British Columbia gas, which is consistent with the KMMEF's natural gas procurement. The average operating conditions for the methanol plant are also used to determine direct plant emissions. These reflect the performance of the catalyst at the midpoint of its useful life. The lower emission scenario also includes higher upstream energy inputs for displaced methanol production and higher feedstock use rates for displaced methanol.

Upper Emission Scenario

Inputs regarding the source of natural gas and mix of electricity could also result in higher GHG emissions. The combination of U.S. average upstream emissions for natural gas production and a marginal grid mix based on potential growth in electricity demand is examined here. Higher feedstock use rates and power generation emissions were assumed for displaced methanol.

[13] The Cowlitz PUD mix is recommended by the Washington Department of Commerce for GHG reporting. The Washington average is a conservative estimate (Appendix B) since the Cowlitz mix has more hydroelectric power and a lower GHG intensity.

Higher emissions from displaced methanol result in lower overall emission from KMMEF methanol.

Market Mediated Scenario

The market mediated scenario examines the second order market effects of a new source of methanol on markets. The KMMEF will increase global methanol supply by about 3%. Several economic assessments have considered the supply and demand of energy resources on market effects (Gillingham, Rapson, & Wagner, 2016; ICF International, 2017b)). The potential effect of natural gas and coal feedstocks on energy markets is examined in this scenario. An increase in demand for natural gas for the KMMEF or feedstocks for other alternative sources of methanol could affect prices with effects on demand. This scenario uses the same energy input assumptions as the baseline scenario but applies market mediated effects to the feedstocks for the KMMEF and alternative sources of methanol. A marginal power generation mix is calculated for imported power to the KMMEF as discussed in Section 2.4.4.

Energy prices can also affect the supply curve for methanol. For example, higher natural gas prices combined with stable coal prices would affect the relative ranking of natural gas-based methanol plants along the supply curve. If gas prices were to rise faster than coal prices, the competitiveness of coal to methanol would be improved. Petroleum prices also affect the relative competitiveness of MTO with olefins from other sources.
The displacement of methanol to MTO plants is affected by the supply and demand of methanol described in Section 4.5.1. The supply of methanol is based on the facilities that could provide methanol to MTO facilities absent the KMMEF. Finally, the displacement effects due to the changing use of coal and natural gas may influence energy markets.

Summary of Scenarios

The range of GHG emissions associated with the KMMEF were examined via the scenarios shown in Table 2.3.

Table 2.3. Scenarios for Life Cycle Analysis

Scenario / Parameter	Baseline	Lower	Higher	Market Mediated
a. KMMEF Operation	Steady State SOR [a]	Steady State Average Operation	Steady State SOR	Steady State SOR
c. Natural Gas Upstream[b]	99.4% British Columbia 0.6% Rocky Mountain	British Columbia	U.S. Mix	99.4% British Columbia 0.6% Rocky Mountain
d Electricity mix	Washington State	Marginal Renewable Power	eGRID for NWPP	Marginal Power, 15% RPS
e. Methanol transport	100,000 tonne tanker	100,000 tonne tanker	50,000 tonne tanker	100,000 tonne tanker
f1. Displaced methanol feed consumption	Average displaced methanol plant	5% more feed than average	5% less feed than average, low energy input feedstock	Average displaced methanol plant
f2. Displaced methanol feed source	Average data for feedstock	Average data, high GHG electric power	GREET feed assumptions	Average data
g. Market Effects on Demand	Minor	Minor	Minor	Market price effect on China Coal

[a] SOR = Start of run. Energy inputs are slightly higher under this condition than end of run (EOR) conditions.
[b] Examined GWP of CH4 and N_2O as a sensitivity

2.4 Data Sources

Calculations of life cycle GHG emissions are based on the energy inputs and emissions for each step in the methanol production process. The data sources for direct emissions, methanol production, and inputs for the upstream and downstream emissions in the life cycle are described below. Data for economic analysis are also described. Since many of the data sources apply to both KMMEF as well as displaced emissions, the data are organized by category rather than a linear path along the methanol life cycle.

2.4.1 Methanol Production Energy Inputs

Several methanol production technologies are currently used in commercial scale methanol facilities throughout the World, however they all have the same key steps.

1. Natural gas reforming – the process of converting natural gas to synthesis gas (a mixture of hydrogen and carbon oxides; also referred to as syngas):

2. Methanol synthesis – the process of converting syngas to methanol; and

3. Methanol distillation – the process of purifying the methanol product to the required purity.

A description of various methanol approaches is described in university lecture materials (Espino, 2015) as well as an assessment by the National Energy Technology Laboratory (National Energy Technology Laboratory, 2014a).

The major difference between the methanol technologies currently in use is in the natural gas reforming section and these are described below. The energy efficiency for methanol production primarily depend on the feedstock and reforming technology selected with the methanol synthesis and distillation technology having a minor impact.

Natural Gas Reforming

The operation of leading natural gas reforming technologies is described below.

Steam Methane Reforming (SMR)

Most methanol facilities use Steam Methane Reforming of natural gas which produces a synthesis gas where the hydrogen is in excess of the stoichiometric requirement for methanol production. This excess hydrogen is burned in the reformer to provide the heat required for the steam reforming process and as a by-product generates steam for the process and to drive the compressors needed in the process.

SMR with CO_2 Addition

Where high carbon dioxide content natural gas or carbon dioxide from ammonia plants is available for import this can be used to improve the efficiency of the SMR based natural gas to methanol process. In this process the extra CO_2 reacts with the excess hydrogen to produce additional methanol. Compared to the SMR process natural gas is burnt in the steam reformer to replace the hydrogen consumed in the process but the overall efficiency is improved.

Combined Reforming

Another approach is to use combined reforming. This process involves a partial natural gas reforming with steam as a primary step, and a complete reforming with oxygen in an Autothermal reformer (ATR) as a secondary step. Combining the two reforming processes creates the optimum synthesis gas composition for methanol synthesis. Again, the heat for the steam reforming process is supplied by natural gas firing and steam is produced as a byproduct. This technology is more efficient than conventional steam reforming.

Ultra-Low Emissions (ULE) technology

ULE technology is a variation of combined reforming and the technology selected for the KMMEF. Both the ULE and Combined Reforming technology use a mix of steam reforming and oxygen reforming. The main difference is that in the ULE technology, process heat is used directly to provide energy for the reforming reaction. With this approach, hot synthesis gas from the secondary reformer (referred to as the Autothermal reformer) flows through the shell side of the primary reformer (referred to as the GHR). This results in no by-product steam production from the process so electrical power needs to be imported to drive the compressors needed in the process instead of using steam turbines.

A detailed description of the Combined Reforming and ULE process is given in Sections 2.5 and 2.6 of the KMMEF FEIS.

The energy inputs and emissions from the KMMEF are based on the specific design for the project. The KMMEF will use ULE technology with a mix of on-site power generation and power import from the power grid so the direct emissions from the project also include natural gas consumed producing on-site power generation.

Coal to Methanol

Producing methanol from coal involves the gasification of coal, in the presence of oxygen (ASIACHEM, 2018; National Energy Technology Laboratory, 2014a; Supp, 1990). The gasification of coal and reaction with steam produces a synthesis gas where the hydrogen content is short of stoichiometric requirement for methanol production. Therefore, synthesis gas containing carbon monoxide is further reacted with steam to produce CO_2 and hydrogen. This additional CO_2 is vented as part of the production process and this emission is accounted for. Coal to methanol plants typically use higher ranking coal as gasifier feed and lower ranking coal such as lignite to generate steam. The steam coal is burned in a boiler. Additional electric power is imported to provide energy for compression and other mechanical equipment.

Table 2.4 shows the coal consumption rates and electric power inputs from various sources. Overall coal consumption is about 2.1 tonne per tonne of methanol. The coal use rates applied in this Study are shown in Table 2.5 with a distinction made at the 500 k tonne/year (ktpa) capacity.

Table 2.4. Inputs for Coal-Based Methanol Production

	kWh/tonne	tonne/tonne methanol		
Type	**Power**	**Feedstock**	**Steam**	**Total**
Coal Gasification, >500 ktpa, this Study	288	1.6	0.55	2.15
Coal Gasification,<500 ktpa, this Study	288	1.68	0.64	2.32
Koppers-Totzek (Reed, 1976)	0	1.652	0.312	1.96
GREET (ANL, 2017b)	0	--	--	1.72
Entrained gasifier, Lignite (Jacobs)	-1030	2.40		2.40
China Range (China Coal Institute)[c]	--	1.42 - 1.59	~0.5	~2
China Auto Energy Research Center	0	--	--	2.297
ASIACHEM, 600 ktpa Design Case 1	566	1.68	0.64	2.32
Bautou, 600 ktpa (HQCEC)	288	1.463	0.57	2.03
ASIACHEM, 1800 ktpa MTO	178	1.72	0.644	2.36
1800 ktpa Design Study (NPCPI)	150	1.419	0.487	1.91
Supp, 1800 ktpa North Dakota lignite	Export	1.84	0.34	2.18

Sources:
Cos*ts to Convert Coal to Methanol* (US EPA, 2015). China coal market research and forecast report (Qixun Industry Research Institute, 2018)
(Wang, 2017) Several coal to methanol technologies identified by (ASIACHEM, 2018; China Coal Research Institute, 2011; National Energy Technology Laboratory, 2014a; Supp, 1990; US EPA, 2015)
(Peng, Zhou, Yuan, & Ou, 2017)

2.4.2 Natural Gas Upstream

Natural gas provides a feedstock for the KMMEF process, onsite power generation, power generation in Washington State, and as well the conversion of crude oil to petroleum products. The production of natural gas includes extraction at a gas well, processing to separate natural gas liquids and sulfur, and transport to the KMMEF or other users of natural gas. The KMMEF will use the NWP interstate pipeline system to deliver its supply of natural gas. The pipeline draws over 99% of its gas from Canada and the balance from the Rocky Mountains as shown in Figure 2.8. NWIW will be contracting and receiving Canadian natural gas, primarily from the Montney formation in British Columbia. About two-fifths of the natural gas entering Washington moves through the Sumas Center, in Canada near the border between Washington and British Columbia. The Northwest Pipeline bidirectional system supplies natural gas from Canada, from the Rocky Mountain region, and from the San Juan Basin in the U.S. Southwest to markets in Washington with the net gas flow headed towards California. A separate transmission pipeline enters Washington from Idaho and moves natural gas from Canada, to the eastern part of Washington. About two-thirds of the natural gas entering Washington flows south to Oregon and beyond (EIA, 2018a); all the natural gas is from Canada.

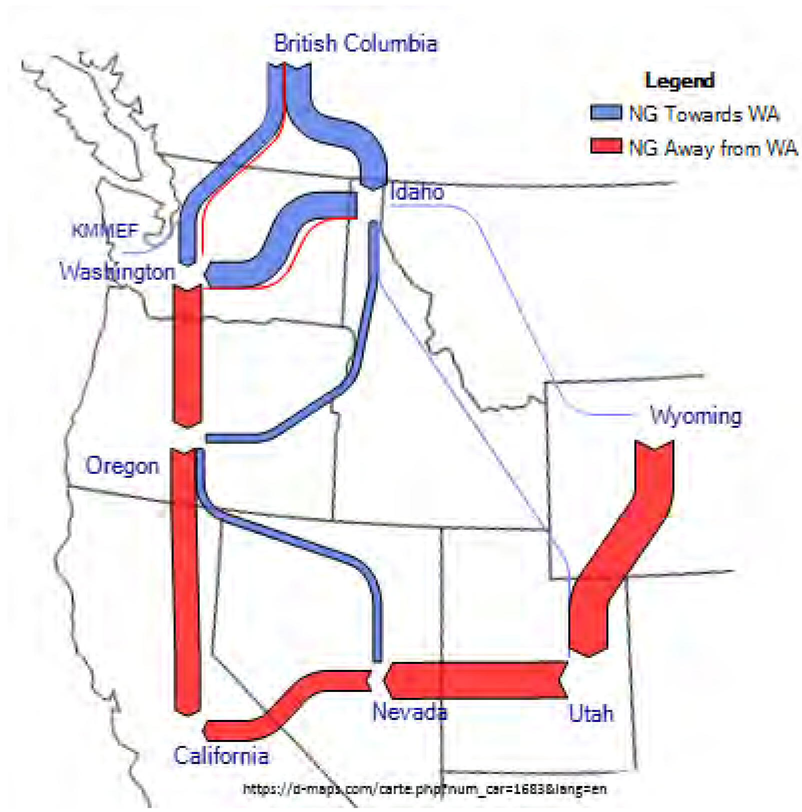

Figure 2.8. Natural gas flow.

Historically, natural gas in the U.S. has been produced from conventional gas wells, but in recent years, there has been substantial growth in production from horizontal wells, which require hydraulic fracturing (National Energy Technology Laboratory, 2014b; U.S. Energy Information Administration, 2016). Figure 2.9 shows the growth of natural gas production in the U.S. Conventional gas production has declined while shale gas and other tight gas resources have grown significantly and are expected to result in a doubling of natural gas production by 2040. Similarly, most Canadian production growth is from horizontal wells and almost universally produced with subsurface fracturing. As noted above, most of the gas for the KMMEF will be from the Montney formation in British Columbia.

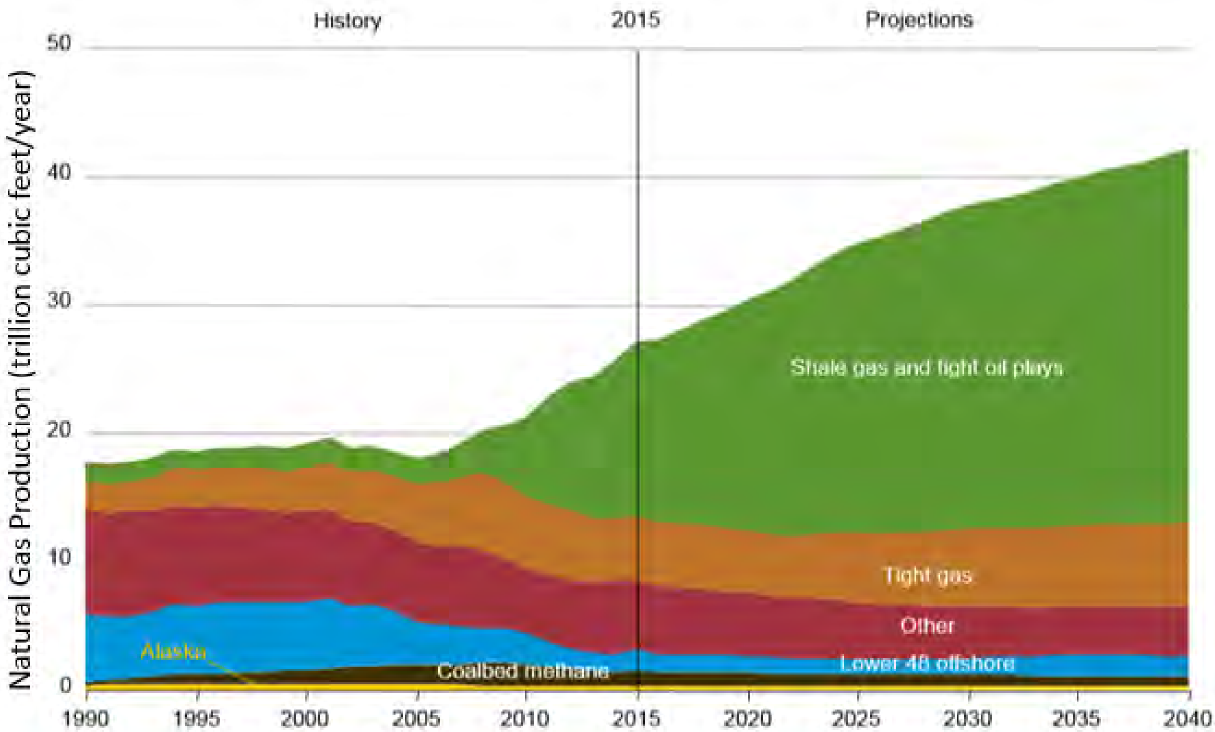

Figure 2.9. U.S. Dry Natural Gas Production by Source.
Source: (U.S. Energy Information Administration, 2015)Figure MT-46 U.S. Dry natural gas production source in reference case

Natural Gas Transport

Natural gas is transported by pipeline; the NWP system typically operates at pressures between 600 and 800 psi. NWP will not be increasing the maximum allowable operating pressure of its system due to the KMMEF. Natural gas fueled compressor engines compress and move gas along the pipeline network. Natural gas sold for residential and commercial use also requires distribution through a local distribution network not related to KMMEF. A description of natural gas transmission systems is provided by a natural gas trade group (NaturalGas.org, 2013). Natural gas flows through a pipeline at constant pressure and the pressure drops as gas is removed from the pipeline and due to pipe friction. As more gas is moved through the pipeline, additional compression energy would be required to move the gas, which is part of the upstream analysis.

Portions of the pipeline are a bidirectional system, and the KMMEF will utilize the existing system to deliver gas, without the need for expansion. The delivery of natural gas to the project may only change the distance or direction of flow in the system and is not expected to affect a change in energy use for compressor operations. The final leg of delivery to the KMMEF will be a new 24-inch 3.1-mile lateral interconnecting with NWP's interstate system without a supplemental compressor. Energy inputs for natural gas production provide the basis for estimating combustion emissions for the upstream component of natural gas in the GREET model. The energy inputs for production are expressed as extraction efficiency.

2.4.3 Coal Upstream

Coal is the primary feedstock for methanol produced in China as well as a component of power generation in the U.S. and China. China is the world's largest producer of coal with a four-fold growth in production in the last two decades as shown in Figure 2.10. Consumption has exceeded production by a small amount, which indicates that China has been a net importer of coal. China is also the world's leader in total coal reserves ahead of the United States and Russia (IEA, 2018).

Most coal reserves are located in the north and north-west of China. The location of coal reserves in regions such as Inner Mongolia makes it logistically challenging to transport coal to power plants, methanol manufacturing facilities, and CTO facilities. Therefore, many methanol facilities that use coal are located close to the coal production resource and the product is transported to coastal cities.

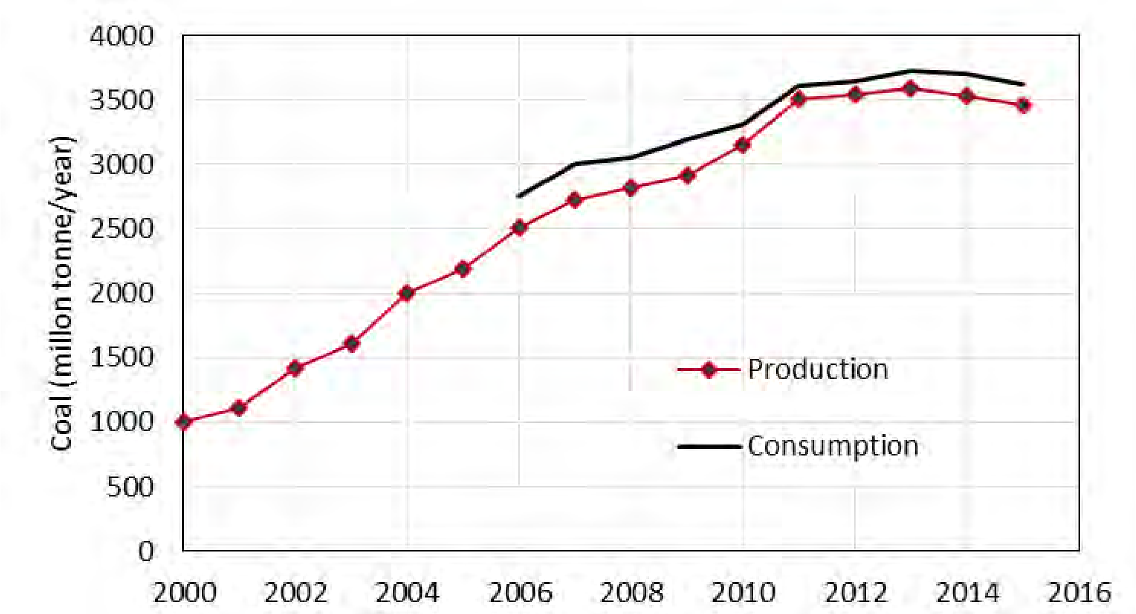

Figure 2.10. China coal production and consumption.
Source: BP, 2017; BP, 2009

Coal Mining

Coal is mined with mechanical equipment which is used to extract and grind coal as well as ventilate underground mines. The primary energy source to power mining equipment is either diesel fuel, fuel oil, or electric power. Coal mine methane is also a source of GHG emissions.

2.4.4 Electric Power Generation

KMMEF will purchase 100 MW of grid power to meet a portion of its electricity requirements.

GHG emissions are calculated with the GREET (ANL, 2017b) model upstream emission factors using the resource mixes described in this section[14]. This section presents several average and marginal resource mixes and presents the GREET estimated life cycle GHG emission factor for each.

The electric power generation mix affects the GHG emissions associated with purchased power. For continuous operation, NWIW will be contracting to purchase electric power from various regional suppliers which will then be delivered through the Cowlitz PUD electrical system. Due to the changing nature of the regional power grid several scenarios for power generation are examined in this Study. These include:

- Washington State average mix
- 100% Renewable
- eGRID NWPP mix
- Marginal Washington mix

Marginal Resource Options

This analysis is intended to estimate the incremental energy inputs and emissions associated with methanol operation. Ideally, the analysis would take into account new sources of natural gas and electric power as well and the effect of displacing other sources of methanol and feedstock. Such incremental or marginal changes in resource mix are difficult to assess. Several factors affect the determination of a marginal electricity mix (Unnasch, Browning, & Kassoy, 2001). First hydroelectric, nuclear, and coal based power would not grow with an increase in power demand. Furthermore, the renewable generation requirements of the Washington RPS must be met, which suggests a trend toward increased renewable generation in future power mix.

A marginal approach was analyzed to determine the resource mix utilized to generate electricity for the KMMEF. A marginal mix should represent the permanent and sustainable load growth associated with the project. Such a mix would correspond to how the grid responds to the new demand and which resources will meet the new load. The new market-served load from the KMMEF is 100 MW or 864 GWh annually.

Several possible methods could provide the basis for assigning a resource mix for marginal power. Figure 2.11 shows the statewide resource mix over time. As can be seen, consumption is trending down; consumption in 2015/2016 is 3,000 to 4,000 GWh lower than consumption in the 5 prior years. Moreover, the Northwest Power and Conservation Council's 7th plan asserts that all load growth forecast for the next 20 years can be met by cost effective conservation. Conservation would result in a marginal resource mix that matches the current average.

[14] The 2016 EIS examines an imported power with a direct GHG emission factor from eGRID2012 these values includes power plant emissions only and is therefore not a life cycle GHG estimate.

The Council's projection may be optimistic; the Department of Commerce (Washington State Department of Commerce, 2016) anticipates that load will increase 15% by 2026 from 2016 levels and will be only partially met by conservation measures. Appendix B shows how a marginal electricity mix with zero hydroelectric and nuclear power is calculated.

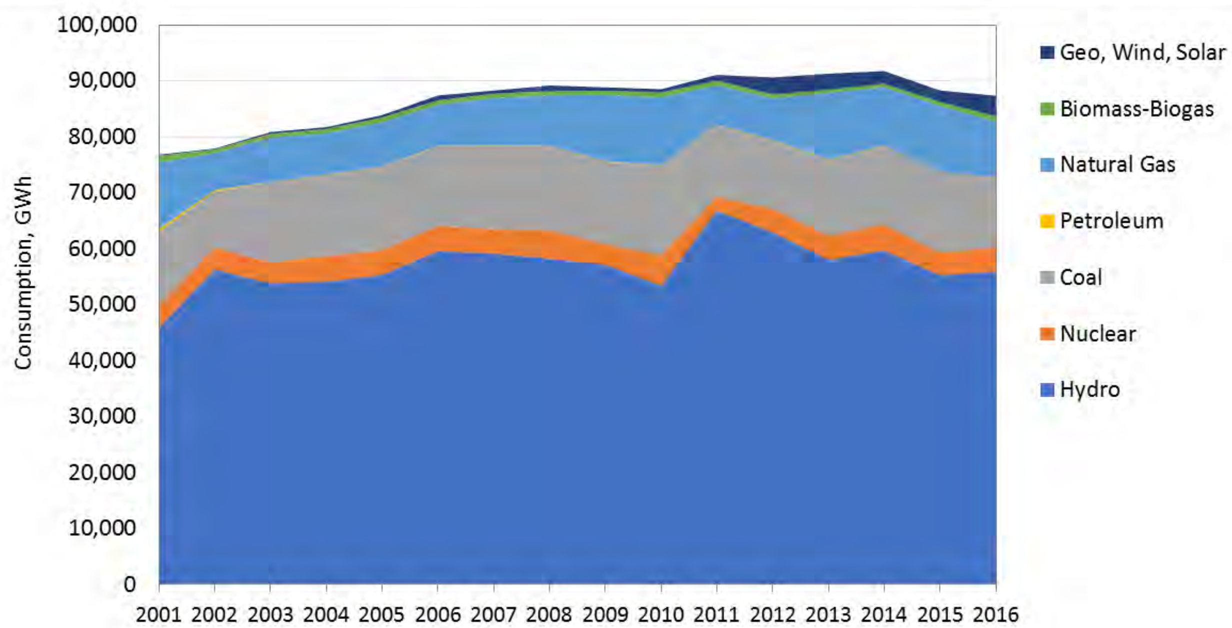

Figure 2.11. Change in Washington State annual electrical energy consumption.
Source: Appendix B

2.4.5 Construction Inputs and Materials

Construction Direct Emissions

Construction emissions correspond to the fuel use identified in this section combined with emission factors for diesel and gasoline. Emissions associated with carbon release from the decomposition of organics materials released during dredging are also estimated.

For each type of equipment, the GHG emissions correspond to the fuel use multiplied by the emission factor for each type of fuel and equipment type. These emissions consist primarily of the fully oxidized carbon in fuel. Some variability in CH_4 and N_2O emissions occur with different equipment types.

Construction Materials

Construction materials for the KMMEF include steel and other metals, asphalt, and concrete. NWIW estimated the weight of materials based on the facility design as shown in Table 3.5. Concrete is divided between the aggregate and Portland cement components. GHG emissions for metals used in construction are determined from Argonne National Laboratories GREET2 model (ANL, 2017a). The model calculates the upstream life cycle emissions for the manufacturing and forming of metals for vehicle manufacturing. A transport distance to manufacturing facilities of 800 miles was assumed with a mix of truck and rail delivery to equipment manufacturing facilities. Thus, the life cycle emissions for materials include material manufacturing from GREET 2 plus 800 miles of transport to a fabrication facility, followed by transport to the KMMEF. Half of the KMMEF pressure vessels and equipment are assumed to be transported by marine vessel from Asia to the KMMEF.

2.4.6 Transport Modes

Transport of methanol from the KMMEF would include marine vessel (tanker) with a tonnage in the range of 60,000 to 120,000 dead weight tonne (actual carrying capacity would be 50,000 to 100,000 tonnes). Tanker traffic is proportional to the amount of methanol shipped. At full methanol production capacity, this would result in 36 to 72 shipments to China per year. A typical tanker vessel is shown in Figure 2.12.

Figure 2.12. Marine tanker for methanol transport.

GHG emissions from methanol distribution are based on transport from Kalama, Washington to Bohai Tianjin, China. As previously stated, there are several MTO facilities in operation and planned adjacent to Bohai Tianjin China and the port is also approximately an equal distance to other major productions centers in Eastern China. The transport includes fuel use for transporting the bar pilot by helicopter, tugboat operation in the Columbia River, and transport in a marine vessel. Similarly, the transport costs for alternative sources of methanol are based on the distance to Bohai Tianjin. Table 2.5 shows the transport distances from leading potential international sources of methanol.

Table 2.5. Distance for Methanol Transport to Bohai China

Location	Distance (kn mi)	Route to Bohai Tianjin, China
Kalama	5,341	Pacific
Medicine Hat CN	5,301	Pacific + 783 rail
New Zealand	5,676	Pacific
Oman	5,910	Malaccan Strait
Saudi Arabia	6,465	Malaccan Strait
Venezuela	9,783	Panama Canal
Trinidad	9,951	Panama Canal
Chile	10,119	Pacific
Louisiana	10,291	Panama Canal
Geismar Louisiana	10,291	Panama Canal

Source: (World Shipping Register, 2018)

Methanol transport within China is accomplished with on-road trucks similar to the one shown in Figure 2.13. The truck has a capacity of 39.6 m^3 or 31 tonne of methanol. Methanol is also transported in barges over rivers when this delivery mode is available (ASIACHEM, 2018). The transport distance used in the development of the economic analysis was based on the distances in Table 2.6.

Table 2.6. Distance for Methanol Transport to Bohai China for Locations in China.

Region	Province	Distance to Bohai Tianjin (km)
Northeast China	Heilongjiang	120
Northeast China	Jilin	120
Northeast China	Liaoning	120
East China	Anhui	600
East China	Jiangsu	600
East China	Shandong	600
East China	Shanghai	600
East China	Zhejiang	600
Central China	Henan	650
Central China	Hubei	650
Central China	Hunan	650
North China	Hebei	750
North China	Shanxi	750
North China	Tianjin	750
Northwest	Gansu	850
Northwest	Inner Mongolia	850
Northwest	Ningxia	850
Northwest	Shaanxi	1,100
Southwest	Chongqing	1,800
Southwest	Guizhou	1,800
Southwest	Sichuan	1,800
Southwest	Yunnan	1,800
Northwest	Qinghai	2,250
South	Fujian	2,800
South	Hainan	2,800
Northwest	Xinjiang	3,222

Source: Google Maps

Figure 2.13. Trailer for hauling methanol in China, 39.6 m^3 capacity.

2.4.7 Petroleum Upstream Emissions

Residual oil used for bunker fuel, diesel fuel, gasoline, LPG and naphtha provide energy inputs to the life cycle of methanol from KMMEF or alternative sources of methanol. The GREET model estimates the emissions from crude oil to petroleum fuels based on the complexity of the oil refineries in different regions of the U.S. Among other parameters the GHG emissions from a refinery are directly related to the density of crude oils measured in API gravity. Crude oils that are light (higher degrees of API gravity or lower density) tend to require less intensive processing which results in lower GHG emissions. The inputs for crude oil production and refining to petroleum products for both Washington and China is discussed in Appendix B.

2.4.8 Economic Data

Economic data provides the basis for determining the competitiveness of participants in the methanol industry. Cost curves provide insight into which production technologies offer financial advantage, the degree of the advantage, and how this is expected to change over time. They identify the lowest-cost regions, countries and plants, both today and into the future, both on a direct production cost basis as well as on a delivered basis with curves that compare cost of local producers with cash cost of imports from major producing regions including freight, logistics and duties.

Key sources of information include the Methanol Institute, Methanex, IHS Markit, the DOE Energy Information Agency (EIA), Wood McKenzie, ASIACHEM and others. The Study team reviewed the current situation with methanol as well as industry forecasts focusing on location of supply, production costs and growth in demand. The team reviewed additional reports and articles on methanol production in general and the KMMEF in particular.

These included:

- analyses from the U.S. Energy Information Administration detailing China's energy usage, imports, supply, capacity, use of methanol in liquid fuels, and its most-recent outlook forecast,
- background information from EIA, Methanol Institute, Argus Methanol report,
- a report on development of China's methanol market and global supply from Argus DeWitt,
- data from the CCFGroup on China's domestic methanol production and regional flows
- background news reports from ICIS on supply and demand of methanol in China, and
- miscellaneous news reports identified by online keyword searches found on-line.

The sources of methanol globally were examined to determine what methanol production capacity would compete with the sources in China shown in Figure 2.14.

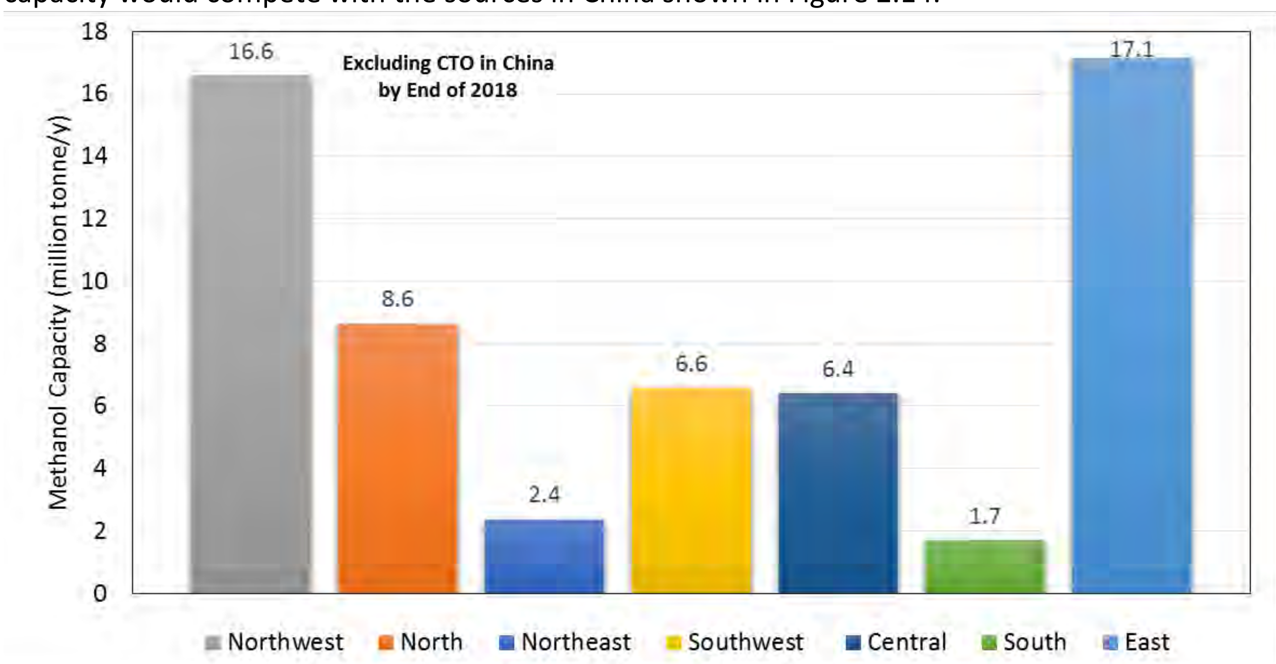

Figure 2.14. Methanol Production Capacity in China by Region. Details of methanol production and resource type are analyzed in Section 4.2.

Natural Gas Price

Natural gas feedstock prices for methanol plants vary regionally. In places such as Saudi Arabia where gas is associated with oil production the effective price to the methanol plant can be as low as $0.80 per mmBtu. In other regions of the world the price of natural gas is affected by local supply and demand as shown in Appendix E. These prices provide the basis for regionally specific feedstock costs.

2.4.9 Olefin Production

Olefins are double-bonded hydrocarbons such as ethylene, propylene, and butylene.
The emissions associated with MTO facilities and other sources of olefins depend on the conversion yield, process fuel, and power. The MTO process includes the energy inputs and process emissions associated with the combustion of process gas. MTO compares to other traditional production methods (Dimian & Bildea, 2018; Ren, Patel, & Blok, 2004, 2008) with similar reactor configurations; however, the energy inputs, fuel gas generation, and olefin yields differ among the technologies. In Section 5.4, below, KMMEF methanol as a feedstock for olefin production is compared to alternative feedstocks with their relative olefin production emissions.

2.4.10 Methanol Use as Fuel

Fuel is one of the many uses of methanol including fuel blending, cooking fuel, and industrial fuel applications (Argus, 2018). Methanol is also converted into products that are used as fuels with the major product being dimethyl ether (DME) which is a propane replacement. The remaining uses include input for biodiesel, MTBE production, and methanol to gasoline. Methanol as a fuel is discussed and analyzed in Section 4.3.5 and Section 5.5.

3. KMMEF EMISSIONS

KMMEF GHG emissions are grouped according to construction and operations. Operational emissions include direct, upstream, and downstream components. Direct emissions include fuel combustion and fugitive emissions. Upstream emissions include the well to gate emissions for natural gas feedstock, electric power, diesel and other fuels as well as those associated with materials of construction. Downstream emissions include transport to Bohai Tianjin, China. Because the end use of methanol is the same as that of displaced methanol, emissions are the same regardless of the production method. The comparison of total emissions through olefin production is examined in Section 5.4.

Data and sources of inputs are described in Section 2.4. Energy use rates are combined with upstream and direct emission factors to determine construction and operation emissions.

3.1 Construction Emissions

Construction is planned for 26 months. Construction emissions include fuel combustion that occurs during construction as well as potential organic carbon releases from dredging. Upstream life cycle emissions consist of electric power for construction as well as the upstream life cycle emissions for fuels. Construction emissions are estimated to be the same for all the scenarios examined in this Study. GHG emissions are calculated for the following:

- Construction equipment operating
- Construction equipment power
- Employee commuting
- Material delivery
- Dredging fuel use
- Organic material from dredging operations
- Material manufacturing for KMMEF

Direct construction emissions are associated with fuel combustion and are described in Section 3.1.1. Indirect[15] or upstream life cycle and carbon release from dredging are described in Section 3.1.2.

3.1.1 Direct Construction Emissions

Direct emissions from construction correspond to the fuel for construction equipment, dredging, and employee commute traffic shown in Table 3.1. NWIW estimated the fuel used for cranes, dozers, compressors, and other construction equipment. The basis for estimating fuel use for other construction activities is described in the table. Material hauling is based on the amount of material, distance to distribution center, and cargo hauling efficiency. Half of the construction materials are assumed to be delivered by marine vessel from Asia.

[15] Material transport emissions could be considered indirect emissions. For the purposes of this Study, fuel combustion on-site and local delivery are treated as direct emissions. Upstream life cycle and dredging carbon release are in the upstream life cycle category.

The establishment of the marine terminal will require dredging of 126,000 cubic yards of sediment from the Columbia River to create adequate depths for vessels to berth at the new marine terminal. Dredging requires removal of sediment with a clamshell or hydraulic dredge (Lee, 2001) and redepositing the material in other portions of the waterway or in an upland location. The European Dredging Association (EuDA, 2016) describes CO_2 emissions from fuel use during dredging operations, which provide the basis for determining fuel use and associated CH_4 and upstream life cycle emissions.

Table 3.1. Energy Inputs for Construction

Construction Fuel	gallons[a]	lb	mmBtu, HHV	Source
Construction Diesel	423,505	2,933,435	56,358	NWIW
Construction LPG	154,135	653,448	14,090	NWIW
Soil Hauling Diesel	37,128	257,172	4,941	227,370 CY, 10 mi[b]
Concrete Hauling Diesel	13,332	92,346	1,774	55,110 CY, 10 mi[b]
Material Hauling Diesel	19,796	137,120	2,634	148,472 tonne, 10 mi[b]
Material Hauling Marine	515,644	4,265,231	77,403	148,472 tonne, 5310 kn [c]
Dredging Marine Diesel	40,373	333,955	6,060	126,000 CY, 2.5 kg CO_2/m^3 [d]
Commute Gasoline	283,961	1,771,375	34,600	560 employee, 26 mo, 30 mi
Total	1,487,876	10,444,083	197,861	

[a] Fuel properties from GREET are in Appendix C.

[b] Truck fuel economy 6 mpg for local delivery including empty backhaul. Transportation is included in upstream data.

[c] Transport of half of equipment from Asia in 100,000 tonne capacity vessel, 85.3 Btu/ton-mi, with empty backhaul.

[d] Fuel use for dredging is calculated from emission rate 2.5 kg CO_2/m^3 of dredged material (EuDA, 2016) combined with marine diesel fuel carbon content.

[e] Average employee count from EIS Appendix K, page 83. Fuel consumption of 24.1 mpg based on VISION model (ANL, 2014) with 50% passenger cars and 50% light trucks. Assume 25% carpooling, 20 working days per month.

The direct combustion emissions depend on the amount of fuel consumed and the carbon content of the fuel. In addition, CH_4 and N_2O emission vary by combustion technology (e.g. boilers or engines). Emission factors for the fuels used during construction shown in Table 3.2 are combined with the fuel use in Table 3.1. Energy use is shown on an HHV basis which is the commercial metric used for most of the industrial activities in this Study. Data supporting the fuel combustion emission factors are described in Appendix C. Fuel use from construction worker commuting is also included.

Constructions emissions from fuel combustion are shown in Table 3.3. Estimates of construction inputs or emissions were not varied as part of the scenario analysis since these emissions represent a relatively small fraction of the overall life cycle emissions associated with the KMMEF.

Table 3.2. Direct Emission Factors for Fuel Combustion

Pollutant	CO_2	CH_4	N_2O	CO_2e
Emission Factor (g/mmBtu), HHV [a]				
Diesel Fuel[b]	74,889	4.4	0.2	75,075
LPG	63,252	3.3	1.0	63,640
Gasoline	71,629	2.8	0.6	71,865
Marine Fuel	79,540	4.3	1.9	80,204

[a] Direct emission factors described in Appendix C.

[b] Emission factor based on 80% trucks and 20% off-road engines with minor effect on CH_4 emissions.

Table 3.3. Direct Emissions from KMMEF Construction

Pollutant	CO_2	CH_4	N_2O	CO_2e	HHV (mmBtu)
Emissions (tonne)[a]					
Diesel Equipment	4,921	0.3	0.02	4,933	65,707
LPG Equipment	891	0.05	0.01	897	14,090
Gasoline Commute	2,478	0.1	0.02	2,487	34,600
Dredging Marine Fuel	6,639	0.4	0.16	6,694	83,464
Total	14,929	0.8	0.2	15,010	197,861

[a] GHG emissions are based on fuel use in Table 3.1 combined with emission factors from Table 3.2.

3.1.2 Construction Indirect and Upstream Life Cycle Emissions

Upstream emissions for construction activity include the production of fuel for construction equipment, generation of power for construction equipment, and manufacturing of materials. The potential release of CO_2 from organic material from dredging are also included here.

Upstream Construction Energy Inputs

Upstream emissions for construction energy inputs correspond to the total energy inputs multiplied by the upstream emission rate from GREET configured with Washington-specific parameters for crude oil production and power generation. The construction phase occurs before KMMEF's power purchase agreements are implemented; therefore, GHG emissions are based on the current electricity mix for Cowlitz County. Upstream emission rates associated with energy inputs for construction are shown in Table 3.4 and are described in Appendix B. Upstream emissions associated with diesel, marine diesel and production are based on the mix of crude oil resources that supply Washington refineries plus imports of refined diesel from Montana. Potential carbon releases from dredging is also included in the table and discussed in the following section.

Table 3.4. Upstream Life Cycle Emissions from Construction Fuel Use and Dredging

Pollutant	CO_2	CH_4	N_2O	CO_2e
Emission Rate (g/mmBtu), HHV [a]				
Upstream Diesel	20,036	20	0.1	20,583
Upstream LPG	10,425	162	0.2	14,523
Upstream Gasoline, E10	21,883	20	0.2	22,428
Upstream Marine Fuel	15,984	10	0.1	16,268
Upstream Power (g/kWh)[b]	46.2	0.1	0.004	50.0
GHG Emissions (tonne)[c]				
Upstream Diesel	1,317	1.3	0.01	1,352
Upstream LPG	147	2.3	0.00	205
Upstream Gasoline, E10	757	0.7	0.01	776
Upstream Marine Fuel	1,334	0.9	0.01	1,358
Upstream Electricity	665	1.5	0.06	720
Dredging Organic C [d]	1,609	0	0	1,609
Total	**5,829**	**7**	**0.1**	**6,019**

[a] Upstream life cycle results from GREET inputs in Appendix B. Washington electricity and crude oil resource mix for petroleum fuels.

[b] Cowlitz PUD generation mix with 14,400 MWh of power consumed during construction.

[c] GHG emissions based on fuel energy in Table 3.1 combined with emission factors in this table.

[d] 1.67 wt%. 50%, carbon 126,000 CY (FEIS Chapter 2), 2 tonne/m^3

Carbon Release from Dredging

Dredging of the new Port of Kalama Birth Basin will redistribute sand which contains organic material that could potentially decompose when disturbed. Organic carbon releases from dredged material are estimated to correspond to 50% of the carbon content (1.67 wt%) of the dredged material. The samples ranged from 0.9 to 1.67% carbon. This level of carbon release is conservative since the dredged material is redeposited or redistributed and not subject to future disturbance.

Upstream Construction Materials

Materials of construction for the KMMEF include steel and other metals, asphalt, and concrete. NWIW estimated the weight of materials based on the facility design as shown in Table 3.5. Concrete is divided between the aggregate and Portland cement components.

Table 3.5. Weight of Construction Materials

Input	Tonnes
Steel	75,600
Rebar	8,813
Stainless Steel	32,400
Copper	20,200
Asphalt	27,600
Aggregate	116,451
Cement	15,880

Source: NWIW

Table 3.5 shows the life cycle emission rates from construction materials and the total emissions based on the quantities in Table 3.4. The GREET2 model provides the estimates for upstream life cycle emissions from metal production. These life cycle results are consistent with other LCA models such as Ecoinvent and the USLCI database. These upstream calculations in GREET2 incorporate the upstream life cycle results for fossil fuels from the GREET1 model and provide the basis for materials such as steel, copper, and stainless steel. The life cycle results for fossil fuels are also consistent with the above referenced LCA models. The remaining upstream emissions are derived from the USLCI database and the GREET1 model. The heaviest materials of construction include concrete and asphalt. These materials; however, require relatively low upstream emissions in their manufacture. GHG emissions associated with metals manufacturing includes energy for mining, smelting, and processing to materials of construction, and transport to manufacturing facilities.

Table 3.6. Upstream Emissions for Construction Materials

Pollutant	CO_2	CH_4	N_2O	CO_2e	Source
Life Cycle Emission Rate (kg/tonne)[a]					
Structural Steel	2,687	4.3	0.022	2,802	GREET2_2017
Rebar	2,020	3.5	0.023	2,115	GREET2_2017
Stainless Steel[b]	5,204	11.3	0.090	5,512	GREET2_2017
Copper [b]	3,083	6.3	0.0555	3,257	GREET2_2027
Asphalt [c]	639	0.4	0.003	651	GREET1_2027
Aggregate [d]	300	0.2	0.000	305	US LCI
Cement [d]	2,900	0.7	0.002	29,18	GREET1_2017
GHG Emissions (tonne)					
Structural Steel	203,102	328	1.6	211,797	
Rebar	17,806	31	0.2	18,644	
Stainless Steel	168,604	365	2.9	178,589	
Copper	62,281	127	1.1	65,801	
Asphalt	17,649	12	0.1	17,963	
Aggregate	34,935	23	0.0	35,518	
Cement	46,051	11	0.0	46,338	
Total	**550,429**	**897**	**6.0**	**574,649**	

Source: GREET2_2017 upstream emissions for metals

[a] Includes additional assumed 800 miles transport, 50% truck, 50% rail to manufacturing facility. Delivery to KMMEF is counted additionally. GHG emissions are based on material use in Table 3.5 combined with upstream life cycle emission rates in this table.

[b]314 Stainless steel composition, 56% steel, 20% Ni, 20% Cr, 2% Mn, 2% Ci, Compare to 6,800 kg CO_2e/kg stainless steel, 3,300 kg CO_2e/kg copper (International Molybdenum Association, 2018)

[c] Emissions for asphalt based on 90% aggregate and 10% residual oil.

[d] Emissions from cement production include limestone production and cement manufacture. Life cycle emissions based on CaO production from GREET1.

3.2 Operational Emissions

Operational emissions from the KMMEF include the direct emissions from facility operation plus upstream life cycle and downstream emissions. Upstream life cycle emission for natural gas and power include the direct emissions from natural gas and power production as well as the upstream life cycle emissions to produce the fuels. Direct project emissions include the on-site emissions from fuel combustion and process emissions. Downstream emissions correspond to methanol transport to the end user including emissions associated with diesel and marine diesel fuel production. A very small amount of upstream emissions for emergency equipment is also included in this grouping. In principle the downstream emissions also include the emissions associated with methanol use in MTO. However, methanol from the KMMEF will displace other sources of methanol used for MTO so there is no net effect. These effects are examined as displacement in Section 4. The effect of displacing olefin manufacturing substitution is examined Section 5.4. The grouping of emissions is shown in Figure 3.1. Emissions from the methanol production and transport include fuel combustion and process emissions and are identified as operational emissions. The indirect or upstream life cycle emissions sources are indicated with bold borders. The emissions for upstream, direct, and downstream phases are discussed in the following sections. Additionally, KMMEF methanol as a feedstock for olefin production is compared to alternative feedstocks with their relative olefin production emissions.

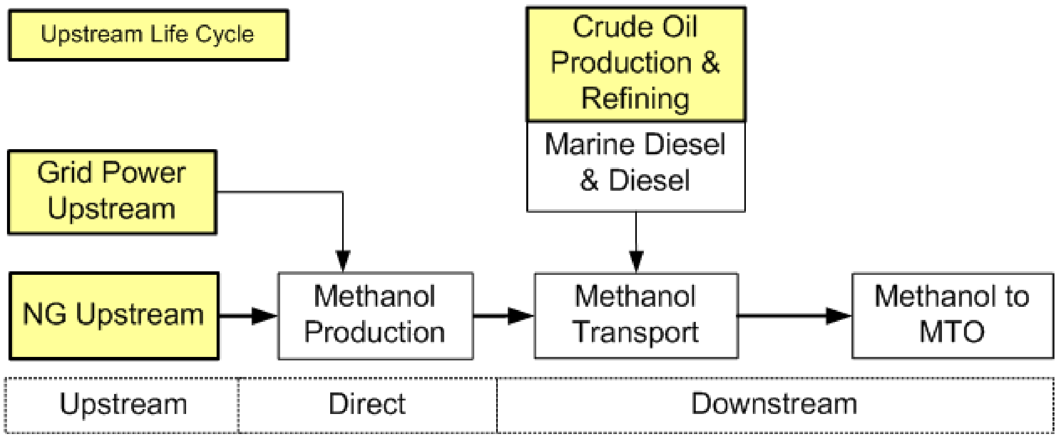

Figure 3.1. Grouping of Operational Emissions from KMMEF.

3.2.1 Upstream Emissions

Upstream emissions from the KMMEF operation include the emissions for natural gas extraction, processing, and transmission (production), as well as grid power generation. These emissions are proportional to the methanol produced during continuous operation.

Natural Gas Production

Natural gas is the feedstock for the KMMEF as well as a key energy input for power generation and crude oil refining. The assumptions for the feedstock for the KMMEF are varied to reflect the range in estimates of methane leakage rates according to the scenario assumptions identified in Section 2.4.2.

The upstream life cycle GHG emissions for British Columbia gas are based on the GHGenius model ((S&T)2, 2013b) with the British Columbia region selected in the model. The GREET model average North American Natural Gas feedstock data provide the basis for Rocky Mountain natural gas. The upstream analysis approach and data sources are described in Appendices A and B. The GHG emissions for the various scenarios are described below.

Table 3.7 shows the upstream emissions for natural gas from British Columbia based on the GHGenius model. The model takes into account the factors associated with different regions in Canada and the U.S. This estimate provides a regionally specific estimate for the feedstock for the KMMEF for a GHGenius model run for natural gas to compressed natural gas (CNG), excluding CNG compression[16]. This approach provides emissions for the natural gas delivered to an industrial user.

Table 3.7. Upstream Natural Gas Emissions for British Columbia

	Emissions (g/mmBtu), HHV			
Processing Step	**CO_2**	**CH_4**	**N_2O**	**CO_2e**
Natural Gas Extraction	2,080	23	0.10	2,675
Fugitive Emissions	997	104	0	3,604
Natural Gas Processing	2,100	9	0.04	2,344
Transmission	1,077	2	0.009	1,131
Total (g/mmBtu)	6,253	138	0.14	9,754
Total (kg/tonne NG)[a]	320	7.1	0.007	498

Source: GHGenius, British Columbia region selected natural gas for compressed natural gas (CNG) pathway excluding compression, year 2020 with IPCC AR4 100-year GWP.
[a]Emission rate × 23,180 Btu/lb, HHV.

Table 3.8 shows the upstream emission for North American natural gas[17]. This resource mix is the basis for the Upper bound estimate for KMMEF methanol and also serves as an estimate for Rocky Mountain natural gas. Note that the GREET model includes a separate upstream calculation for natural gas to power generation facilities that reflects the more direct transmission to power generation facilities than other industrial users of natural gas. The assumptions for natural gas for power production were not modified.

A recent Study from the Environmental Defense Fund, Stanford University, and other researchers (Alvarez et al., 2018) estimates higher average US emissions from natural gas extraction operations based on various measurement techniques described in Appendix B and in footnote to Table 3.9. The effect of this emission level is examined as a sensitivity analysis in section 6. This emission level affects both natural gas production and power generation.

[16] The scenario year in GHGenius affects the power generation mix and does not include projections for lower natural gas extraction emissions.
[17] The default natural gas resource in the GREET model.

Table 3.8. Upstream Natural Gas Emission Rates for North American Natural Gas

	Emissions (g/mmBtu), HHV			
Processing Step	**CO_2**	**CH_4**	**N_2O**	**CO_2e**
Natural Gas Extraction	2,127	8.0	0.019	2,334
Extraction Fugitive		123		3,064
Natural Gas Processing	1,666	3.9	0.013	1,769
Processing Fugitive	702	6.2		856
Transmission & Storage	1,651	18	1.3	2,467
Transmissions Fugitive		40		1,009
Total (g/mmBtu)	6,146	199	1.3	11,499
Total (kg/tonne NG)	**314**	**10.2**	**0.07**	**588**

Source: GREET1_2017, zero distribution emissions, IPCC AR4 100-year GWP
Upstream life cycle emissions are 14,800 g CO_2e/mmBtu if CH_4 extraction fugitive emissions are double as estimated in (Alvarez et al., 2018)
[a]Emisson rate × 23,180 Btu/lb, HHV.

Table 3.9 shows the upstream GHG emissions for natural gas feedstock for the KMMEF. The natural gas use rate, which includes both feedstock, on-site power generation, and other uses of natural gas is multiplied by the upstream factors in Table 3.7 and Table 3.8. Variability in the natural gas leak rates results in the primary difference among the emission estimates (see appendix B1 and section 6). Natural gas use rates for the KMMEF are described in Section 2.4.1.

Table 3.9. GHG Emissions from Natural Gas Feedstock

Baseline	Baseline	Lower	Upper	Market Mediated
Natural Gas Use (mmBtu/tonne)	29.6	29.2	29.6	29.6
Natural Gas Production Mix	99.4% British Columbia 0.6% Rocky Mountain	British Columbia	North American Natural Gas	99.4% British Columbia 0.6% Rocky Mountain
GHG Emissions (kg/tonne methanol)[a]				
CO_2	185.1	182.6	181.9	185.1
CH_4	4.1	4.0	5.9	4.1
N_2O	0.004	0.004	0.04	0.004
CO_2e	289.0	284.8	340.3	289.0

Source: British Columbia GHG emission from Table 3.7. Rocky Mountain (RM) GHG estimated to be the same as North American Natural Gas (NANG) from GREET in Table 3.8. Natural gas use from Table 3.12. Upper GHG emissions are 520 kg CO_2e/tonne if total fugitive CH_4 minus distribution is 2.3% of delivered gas as indicated in (Alvarez et al., 2018). An additional sensitivity with 4 times the emission rate for extraction in the U.S. inventory is also examined as a sensitivity in Section 6.1. [a] GHG emissions based on upstream life cycle emission rate in this table combined

[a] GHG emissions correspond to natural gas use rate and weighted natural gas production mix from Tables 3.7 and 3.8.

3.2.2 Imported Power Generation

The KMMEF will import 100 MW of electric power from the regional power market through the Cowlitz transmission system during continuous operation. Upstream emissions from power used by the KMMEF depend on the power use rate for the KMMEF and the generation mix. Table 3.10 shows the GHG intensity for the power generation mixes identified in Section 2.4.4. The GHG intensity depends largely on the renewable content and the amount of coal in the resource mix. However, the KMMEF will be a significant consumer of electric power in Washington. Even though the Washington resource mix is over 50% hydroelectric, power demand from the KMMEF will not result in the production of additional hydro power. In addition, the hydroelectric renewable attribute may not be assignable to the power purchased by the KMMEF. For example, other customers of hydroelectric power may contract for the hydroelectric zero GHG attribute in Washington power.

The other resource mix options in Table 3.10 represent the GREET results for the range of expected GHG emissions associated with different generation resource mixes. Since the KMMEF will be a new and permanent load, the facility many induce the production of new renewable power such as solar or wind, which GREET treats with a GHG intensity of 0 g/kWh. Alternatively, a marginal resource mix that excludes hydroelectric power and supports the compliance with a 15% RPS would have a GHG intensity of 85.6 g CO_2e in 2020 and drop to 75 g CO_2e/kWh by 2040 with a mix that contains zero coal. A new demand for electric power will not result in additional hydroelectric or nuclear power being generated as no new resources are being developed. Therefore, a marginal mix excludes these resources.

Table 3.10. Life Cycle GHG Emission Rates for Electricity Resource Mixes

		Emissions (g/kWh)			
Resource Mix	**Life Cycle Step**	**CO_2**	**CH_4**	**N_2O**	**CO_2e**
Washington	Upstream	8.2	0.38	0.001	17.9
	Power Plants	195.6	0.01	0.003	196.7
Renewable	Upstream	0	0	0	0
	Power Plants	0	0	0	0
eGRID NWPP[a]	Upstream	11.5	0.56	0.001	25.7
	Power Plants	297	0.01	0.00	298.9
Marginal	Upstream	20	0.66	0.003	37.7
	Power Plants	219	0.01	0.002	219.4

Source: GREET1_2017 with inputs from Appendix B.

[a]eGRID result is 341.5 g CO_2e/kWh for power plant and upstream if natural gas fugitives correspond to 2.3% of gas throughput compared to 324.5 g CO_2e/MJ above.

Table 3.11 shows the life cycle GHG emissions per tonne of methanol associated with imported power for each scenario[18]. The GHG intensity from Table 3.10 is combined with the expected rate of import power per tonne of methanol to determine the GHG emissions per tonne of methanol.

Table 3.11. Life Cycle GHG Emissions from Imported Power

Baseline	**Baseline**	**Lower**	**Higher**	**Market Mediated**
Power (kWh/tonne)[a]	240	240	240	240
Generation Mix	WA	Renewable	eGRID	Marginal
GHG Emissions (kg/tonne methanol)[b]				
CO_2	48.9	0	74.1	57.4
CH_4	0.09	0	0.1	0.2
N_2O	0.001	0	0.001	0.001
CO_2e	51.5	0	77.9	61.7

Source: GREET1_2017 model with Appendix B inputs

[a] Imported power corresponds to 100 MW × 24 h/10,000 tonne methanol/day

[b] GHG emissions correspond to imported power in this table combined with emission rates in Table 3.10.

[18] The contribution of electric power is identified explicitly for each scenario because of the fraction of the total life cycle emissions and the variability in the range of emissions.

3.3 Direct KMMEF Emissions

Direct emissions from the KMMEF correspond primarily to the combustion of natural gas for on-site power and the unconverted CO_2 from the methanol production process. Natural gas for process boilers, flares and backup diesel equipment also contribute to direct GHG emissions. The natural gas use rate affects the upstream natural gas emissions previously discussed.

Emissions from the KMMEF are calculated during continuous operation in order to provide a basis of comparison for the displaced methanol. Energy inputs and emissions from continuous operation are based on the process design and correspond to a mass and energy balance between the natural gas feed, methanol produced, and emissions. A carbon balance provides the basis for the net emissions followed by a summary of the total KMMEF emissions.

3.3.1 Carbon Balance

GHG emissions from the methanol production process consist of fired natural gas and fuel gas. CO_2 emissions are represented by the carbon balance shown in Figure 3.2. Natural gas is combusted in a combined cycle power plant as well as boilers. In addition, fuel gas from the methanol plant is burned in the boilers. The carbon balance shows the mass, energy content and carbon in the natural gas to the facility. The distribution of the natural gas streams is also shown. The net CO_2 emissions from the methanol plant are consistent with a carbon balance as per the following equation such that:

$$C_K = C_{NGF} - C_{MeOH} + C_{NGP} \quad (4)$$

Where:

C_K = Carbon emissions from KMMEF
C_{NGF} = Carbon in natural gas feedstock
C_{NGP} = Carbon in power plant fuel
C_{MeOH} = Carbon in methanol

Thus the carbon in the fuel gas is determined by difference and is also consistent with the process design. The natural gas inputs correspond to feed for the methanol production system. A small portion of the feed natural gas also provides boiler fuel as shown in Figure 3.2.

Natural gas is also the source of electric power for on-site power production. On site power production with a combined cycle power plant provides 110 MW or 264 kWh of power per tonne of methanol. A heat rate of 7500 Btu/kWh[19] of natural gas for power generation requires 19,800 mmBtu/d, HHV basis. The energy consumption corresponds to a lower heating value efficiency of 50.4%.

[19] Based on information provided from turbine manufacturer.

Table 3.12 shows the total natural gas inputs during continuous operation based on the facility design. These maximum natural gas inputs occur at the start of operation where natural gas to the boiler is slightly higher than at the end of run. Total natural gas inputs are slightly lower at the end of run.

Table 3.12. Natural Gas Inputs to KMMEF

Natural Gas Input	Methanol Plant	On Site Power Generation	Total Natural Gas Feed
tonne/h	225.4	16.1	241.5
tonne C/h	167.3	12.0	179.3
C wt %	74.25%	74.25%	74.25%
mmBtu/tonne, HHV	27.65	19.8	29.63
mmBtu/d, HHV	276,512[a]	19,800	296,312

Source: NW-IW process design. Start of Run configuration.

[a] Natural gas to boiler is 8,661 mmBtu/d during SOR and drops to 7,777 mmBtu/d at EOR condition

The additional natural gas inputs in Figure 3.2 are based on the process design for the start of run (SOR) operation as SOR has the highest emission value. Small levels of VOC and CO emissions are represented as fully oxidized CO_2.

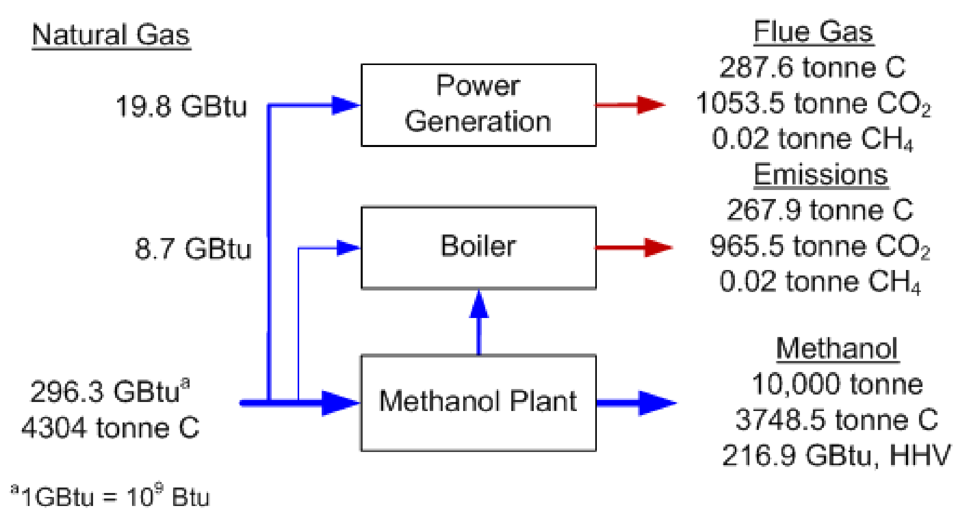

Figure 3.2. Carbon Balance for KMMEF Methanol Plant daily operation (SOR)

The carbon balance in Figure 3.2 provides the basis for determining CO_2 emissions and the energy inputs to the power plant/boiler provide the basis for determining CH_4 and N_2O emissions, which corresponds to a small fraction of the overall GHG emissions.

3.3.2 KMMEF Methanol Production Emissions

Emission values are based on continuous operation of KMMEF in order to provide a comparable basis for displaced methanol.

Table 3.13 shows the direct emission from the KMMEF during the start of run operation. CO_2 emissions from the boilers are based on a carbon balance of input natural gas and exit methanol such that the carbon in the natural gas input is either converted to methanol or carbon emissions in the boiler. The emissions from the gas for flare pilot, vent scrubber, or power generation turbine are calculated separately. This carbon balance assures that the natural gas input and upstream emissions are consistent with the process emissions plus the flare pilot. During continuous steady-state operation, no emissions occur from the flare or the fireboxes. These emission rates are consistent with the requirements for the conversion of natural gas feedstocks and power plant fuel to methanol.

Table 3.13. Direct Emissions from KMMEF during Continuous Operation.

	Continuous Operation				**FEIS[d]**
Emission Unit	**CO_2**	**CH_4**	**N_2O**	**CO_2e**	**CO_2e**
GHG Emissions (tonne/yr)[a]					
Boilers	347,571	5.9	0.6	347,894	548,852
Firebox Heaters	0	0	0	0	1,397
Cooling Tower	0	0	0	0	0
Flare Pilot	154.7	0.003	0.000	155	155
Flare[b]	0	0	0	0	3,175
Tank Vent Scrubber	5.6	0	0	5.6	5.6
Ship Vent Scrubber[c]	0	0	0	3.4	0.0
Tanks	0.06	0	0	0.06	0.06
Emergency Generators	271.9	0.01	0.002	273	273
Emergency Fire Pump	44.8	0.0	0.0	45.0	45.0
Component Leaks	0.1	0.4	0	10.4	10.4
On-Site Combustion Turbines	379,232	7.2	0.7	379,620	421,000[e]
Total Direct Emissions	727,281	13.5	1.3	728,002	975,000[e]
kg CO_2e/tonne methanol[f]	202.0	0.0037	0.0004	202.2	270.8

Source: Carbon balance from Figure 3.2 based on design data from NWIW. Energy throughputs are based on process design for continuous operation

[a] CO_2 emissions for boilers and power generation unit are based on the carbon balance in Figure 3.2 CH_4 and N_2O emission rates are proportional to CO_2 in Appendix C. Other sources correspond to the FEIS results.

[b] Flare emissions occur intermittently during upset conditions. Since KMMEF will not operate during upset conditions annual emissions will be lower if the flare operates

[c] The vent scrubber results in VOC emissions that are reported as fully oxidized CO_2 In the FEIS, these emissions are counted as VOCs

[d] Source: FEIS Chapter 4 Table 4.3 (converted from short to metric tonnes) × 0.9072

[e] FEIS Table 4-4, Total does not match due to rounding.

[f] Annual emissions divided by 3.6 million tonnes per year

The direct CO_2e emissions from the FEIS, which are used for the permitting process, are also shown for comparison purposes. However, these are higher than the continuous operation values as they are based on the maximum emission rates for each operating unit and including flare and firebox emissions that would not occur during continuous operation. The FEIS values also includes emissions for three boilers while two would be in operating at any period in time.

3.4 Downstream KMMEF Methanol Emissions

Downstream emissions from the KMMEF consist of transport to MTO facilities in China. Additionally, Section 5.4 discusses KMMEF methanol and alternative feedstocks with their relative olefin production emissions.

3.4.1 Methanol Transport

Methanol from the KMMEF will be transported to Bohai Tianjin, China in tankers with a tonnage in the range of 60,000 to 120,000 dead weight tonnes (actual carrying capacity would be between 50,000 and 100,000 tonnes). Methanol will be loaded onto the tanker which transits down the Columbia River to the Pacific Ocean. The tanker will make a 5,310-nautical mile trip to Bohai Tianjin, China. The tanker will return with an empty backhaul.

The transport of methanol from Kalama to China includes a number of support efforts and resulting GHG emissions. During docking and undocking two assist tugs will guide the ship to and from the dock. Vessel pilots will be transported to and from the ship by helicopter and or motor vessel. The energy inputs, emission factors and transport distances for each transport segment are shown in Table 3.14.

Table 3.14. Distance and Energy Intensity for Marine Transport to Bohai Tianjin China

Transport Leg	kn mi	Btu/ton-mi, HHV	Capacity
KMMEF Transport			
Kalama Piloting		0.0000004	Helicopter, Tug
Kalama to Bohai	5,310	46.3	100,000 tonne
China Piloting		0.0000002	Helicopter, Tug
Bohai to Kalama	5,310	39.0	100,000 tonne
KMMEF Transport			
Kalama Piloting		0.0000008	Helicopter, Tug
Kalama to Bohai	5,310	85.2	50,000 tonne
China Piloting		0.0000005	Helicopter, Tug
Bohai to Kalama	5,310	71.9	50,000 tonne

Source: Energy intensity for marine transport based on GREET model T&D Sheet.
1 hour of tugboat operation for docking and departure, 43.5 gal/h (ARB, 1999) 200
Helicopter fuel use from aircraft calculator.com, 57.6 gal/h, 15 minute one way trip from Astoria, WA

Table 3.15 shows the parameters for transportation. These include the cargo hauling energy use factors from the GREET model that take into account the outbound and empty back haul energy consumption. Emissions from the trip are based on the combustion of residual oil including its upstream emissions. The emission factor for residual oil is based on the GREET model.

Marine vessels will operate with on-shore power when docked at the KMMEF. The power for vessel operation is included in the overall power requirements identified in Section 3.2.

Table 3.15. Transportation Energy Inputs and Emission Factors for Marine Transport to China

Pollutant	CO_2	CH_4	N_2O	CO_2e
Emission Factor (g/mmBtu), HHV				
Direct Diesel	73,105	3.9	0.6	73,371
Direct Marine Diesel	79,540	4.3	1.9	80,204
Upstream WA diesel	20,036	20	0.14	20,583
Upstream WA marine diesel	15,984	10	0.1	16,268
Upstream China diesel	13,016	175	0.2	17,451
Upstream China marine diesel	9,726	165	0.2	13,906
Emissions (kg/tonne methanol) 100,000 tonne capacity[a]				
Direct Diesel	0.0	0.00000	0.00000	0.0
Direct Marine Diesel	45.7	0.0025	0.0011	46.1
Total Direct Emissions	**45.7**	**0.0025**	**0.0011**	**46.1**
Upstream diesel	0.0	0.0000	0.0000000	0.0
Upstream marine diesel	7.5	0.047	0.0001	8.7
Total Upstream Petroleum	7.5	0.047	0.0001	8.7
Emissions (kg/tonne methanol) 50,000 tonne capacity[a]				
Direct Diesel	0.0	0.0	0.0	0.0
Direct Marine Diesel	84.2	0.005	0.002	84.9
Total Direct Emissions	**84.2**	**0.005**	**0.002**	**84.9**
Upstream diesel	0.0	0.0	0.0	0.0
Upstream marine diesel	16.9	0.01	0.0001	17.2
Total Upstream Petroleum	**16.9**	**0.01**	**0.0001**	**17.2**

[a] GHG emissions correspond to fuel use in Table 3.15. Table 3.15 combined with direct emission factors from Appendix C and upstream life cycle emission rates in Appendix B. CO_2e emissions for Washington Crude Oil from the OPGEE model published by California Air Resources Board (California Air Resources Board, 2017; El-Houjeiri, Masnadi, Vafi, Duffy, & Brandt, 2017).

3.4.2 Upstream Life Cycle Emissions for Petroleum Fuels

Upstream life cycle emissions are associated with fuel used for transportation to China including pilot vessel and helicopter diesel fuel and marine bunker fuel. Table 3.15 shows the GREET results for the upstream fuel cycle of marine bunker fuel and diesel fuel used to transport methanol to China and are described further in Appendix B. Upstream emissions are calculated for bunkering in both Washington and China based on the crude oil resource mix and power generation mix for the U.S. and China respectively. The upstream emissions for petroleum products are similar for both regions because both countries have complex oil refineries. The higher GHG intensity of China electric power contributes to a higher GHG intensity but no Canadian oil sands sourced crude oil was assumed for the China petroleum mix; so the overall upstream emissions calculated in GREET are comparable.

The energy use rates in Section 2.4.6 are combined with the prior upstream emission rates to calculate the upstream emissions associated with petroleum fuels for the KMMEF. The upstream component of the calculations of transport modes and emission factors in Section 3.4.1 are summarized as shown in Table 3.15.

4. Market Analysis and Economics

Methanol is produced, transported, and consumed around the world. It is produced from a range of feedstocks including coal, natural gas, coke oven gas and others and is used in the production of a wide range of materials and products in common use worldwide including use as a fuel. This Study is focused on methanol consumed as a feedstock for olefin production (MTO). This section studies the alternatives to KMMEF methanol and the displacement effects KMMEF will have on methanol supply and its effect on related markets such as coal in China.

The alternative to KMMEF methanol is another source of supply. Factors affecting this supply include

- Alternative methanol production capacity
- Future outlook for supply and demand
- Competition among methanol producers and access to markets

This Study focuses on the demand for methanol on the east coast of China where demand has grown and continues to grow rapidly as a feedstock for olefin production. Most of this demand is met with domestic Chinese coal-based production and some by imports. Most sources expect the growth in methanol demand to continue for the foreseeable future and that low cost imported product will continue to supply this region.

This section analyzes displacement effects in the context of global and China methanol supply. The analysis examines where methanol is produced in the world today and where production capacity in the future is expected. The cost of methanol delivered to East China is determined based on the feedstock, technology, and location of methanol production facilities. The capacity for methanol production is combined with China demand to determine the methanol producers that would be displaced by the KMMEF. The effect of alternative sources of olefins and alternative uses of methanol are also examined.

4.1 Displacement Effects

Displacement effects are a normal economic process in an evolving market. New producers provide supplies of products on the market and if the cost of production is lower than another producer, that producer must either find new markets or cease production. Such a displacement effect is associated with all new producers of materials. Plants age and technology evolves resulting in opportunities for new capital to enter the market and provide new cost competitive supplies. These new investments may serve a growing market, or they may compete for portions of the existing market. Existing plants have an advantage over potential new competitors as their capital investment is, in economic terms, sunk. That is, the investment has been made and cannot be easily withdrawn. For existing plants, the decision to produce additional product is only dependent on the current cash cost of production being less than the market price. New construction must justify their investment decision by expecting to recover both capital and cash production costs and earn a return on investment.

When lower cost inputs, innovative production processes, and production efficiencies justify the investment in new plants, while the market is continuing to grow, even in the absence of increased demand, high cost facilities must reduce production costs to continue to compete in the market. The US aluminum industry, once a world leader, has shuttered much of its capacity as new technology and innovative processes around the world produced less costly product. A similar evolution is occurring in world methanol supply. Low cost and readily available natural gas, innovative processes for conversion to methanol, and efficient transportation offers low cost product to the world market.

The KMMEF introduction of lower cost methanol into the Chinese olefin markets will both meet growing methanol demands and displace higher cost producers. Decision makers will reconsider production and investment decisions as lower cost product becomes available. Natural gas at current and expected prices is simply a superior input for methanol production.

4.1.1 Marginal Producers

In commodity markets, producers compete for sales primarily with price. As the delivered market price is reduced by lower cost feedstocks or new technologies that foster lower production cash costs, producers that cannot meet the market price will restrict or cease production. The producer with the highest cash cost for delivered product is referred to as the marginal producer. A reduction in the market price will cause the marginal producer to stop production, the next higher cash cost producer then becomes the marginal producer. In the current methanol market Chinese coal to methanol plants are the marginal (highest cost) producers.

4.1.2 Macroeconomic Effects

There is a significant difference between short run and long run economics. The options available to suppliers are more extensive in the long run and hence different behavior is expected in the face of a changing market. In the short run, capital is immobile, logistics are set, and client relationships are established, some by contract, some by habit. In the long run, capital is mobile and suppliers are free to seek the best use of their capital in the current or alternative markets.

KMMEF will provide methanol that competes with the merchant methanol supply for Eastern China olefin producers. Some plants, internationally and within China, are unable to provide methanol to this market as their output is: committed to an integrated or nearby downstream facility; not competitive as small plants are unable to achieve the economies of scale required to produce cost competitive supplies; and, challenged by plant locations that result in high transport costs that reduce their competitiveness or are simply uncompetitive. In this Study we assess the world-wide supply of methanol and eliminate those plants that will not provide product to Eastern China.

This Study estimates the long-run supply curve for methanol to Eastern China[20] assuming that olefin producers are price takers, accepting the current market price for methanol, or other feedstocks.

The analysis considers plants that are likely suppliers to Eastern China and excludes facilities that do not have access to sell to Eastern China MTO plants. The supply curve takes into account feedstock cost, technology type, plant location, and economies of scale. The analysis is undertaken on a cash cost basis, which excludes financing and capital costs. This approach reflects the fact that plants with sunk cost will continue to operate if they can provide methanol on a cash cost basis.

This analysis develops a supply curve for a commodity traded in the world market. Methanol is produced in many regions where producers may operate in market or planned economies. How will the nature of the economy impact the factors of production or the price the producer is willing to accept? The supply curves developed here are based on the supply and demand for the commodity in a merchant market. The analysis is based on the assumption that no government subsidy is provided to the producer or the buyer and that the cash price of the product must cover the cost of production. Production costs are based on market input prices, process efficiency standards, and market-based logistics costs. Whether the product is produced in a market or in a planned economy, the product will be sold in a world commodity market at prices determined by supply and demand. This assumes that the producers will seek to cover their production costs whenever offering product to the market and will behave rationally in response to both market forces and policy direction. In the case at hand, China has stated an economic priority and policy to promote their chemicals industry and this has borne out in the development of domestic coal chemicals production. As discussed below, in the absence of attractive imported methanol, coal based domestic methanol production will continue to rise to meet growing industry needs based both in economic and market forces as well as policy direction.

4.2 Methanol Supply

Methanol is a globally traded commodity. Production facilities exist in many locations in the world as discussed in Section 4.3. Globally, over 80 methanol production facilities have capacity over 500,000 tonnes/year. Total global production capacity is 110 million tonne per year for 239 facilities. The median plant capacity is 300,000 tonnes/year. Figure 4.1 shows the mix of feedstocks based on the production capacity of global facilities. Natural gas represents slightly more than 50% of the capacity.

[20] Under current market conditions, some supply to Eastern China Olefin plants is based on higher cost producers. This is a short run condition that will equilibrate in the long-run.

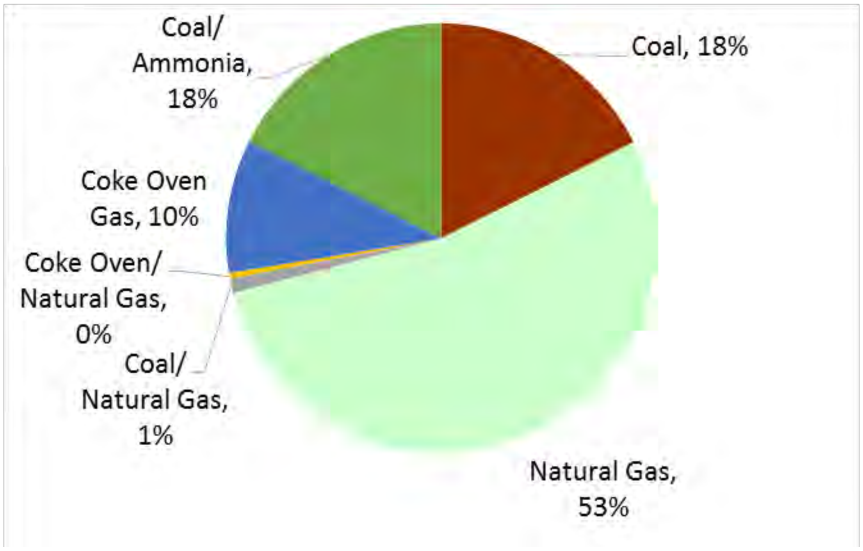

Figure 4.1. Global Methanol Production Capacity by Feedstock.
Source: Tables 4.1 and 4.2

4.2.1 International Methanol Supply

Outside of China, natural gas is the most commonly used feedstock to produce most of the methanol in the world. These facilities are located near either a location with good pipeline access to natural gas resources or near the gas fields themselves. Several methanol plants have been built to take advantage of stranded natural gas resources in places where the natural gas has limited access to market. Such regions include the Middle East, New Zealand, and Trinidad.

The recent abundance of natural gas in North America has resulted in creating the need for economical options for moving those resources to market. Table 4.1 shows the location, capacity, and feedstock for methanol production facilities outside of China. Virtually all of the capacity is based on natural gas as a feedstock.

4.2.2 China Methanol Supply

Most of China's supply is based on coal as a feedstock. Coke oven gas is also a feedstock and a few facilities operate on natural gas. Given the shortage of natural gas in China, the NDRC government has issued a Natural Gas Utilization Policy in 2012. Considering the social, environmental, and economic benefits of natural gas utilization and the characteristics of different users, in the policy, natural gas users are divided into 4 classes, 1) priority classes, 2) allowable classes, 3) restricted classes and 4) prohibited classes. Using natural gas instead of coal to produce methanol falls within a prohibited class. Therefore, new methanol plants have not been able to use natural gas as feedstock since December 2012. Even with goals to reduce inefficient coal to methanol an additional 12,000 ktpa of coal-based methanol production capacity is expected to be installed by 2023 (ASIACHEM, 2018). 16 new coal to methanol plants with a total production capacity of 12,320 ktpa are expected to be built primarily in Inner Mongolia and Shanxi. The plants would have the capacity to sell 8,170 ktpa of methanol to external customers.

Table 4.1. Global Methanol Production Facilities

Region	Facilities		Capacity (k tonne/year)[a]	
	Natural Gas	Coal[b]	Natural Gas	Coal
South America	11		11,450	
Middle East	7		13,770	
North America	7	1	10,196	204
Africa	1		3,300	
Southeast Asia, New Zealand	13		7,467	
Europe, Russia	15	1	8,900	200
Total	**54**	**2**	**55,083**	**404**
China	16	167	6,835	52,560
Global Capacity	**70**	**169**	**61,918**	**52,964**

[a] Production capacity estimated by end of 2018. Some facilities with multiple methanol units may be counted as one.
[b] Includes coke oven gas and combined coal/natural gas facilities. (excludes CTO Facilities)
Sources: (ASIACHEM, 2018; Fisher, 2014; Methanex, 2018)

In China's Twelfth five-year plan (2011 to 2015), the national government sought to cap methanol production capacity at 50 million metric tons per year by 2015, however due to the rapid growth of demand/supply generated by the Eleventh five year plan (2006 to 2010), by the end of 2017, the total capacity of methanol facilities in China has nearly reached 59.4-million tonnes/year. Total demand reached 55 million tonnes including 8.3 million tonnes of overseas supply. In China's Thirteenth five-year plan (2016 to 2020) stated that low-carbon development will be taken as an important driving force for economic improvement and efficiency improvement and recognized the need to accelerate the elimination of outdated and excess production capacity. The plan also forbids the construction of projects smaller than 500,000 tons per year of coal to olefins and 1 million tonnes per year of coal to methanol. Environmental concerns appear to be the main reasons for containing the expansion of a coal-based chemical industry. These concerns include regional pollution, broader environmental issues, potential water resource shortages, and competition with the power industry for coal resources. Despite targets for the reduction of coal to methanol, many coal to methanol plants continue to operate. China's goal to limit coal based methanol is driven by the desire to reduce both local criteria pollutants and greenhouse gas emissions. However, coal based methanol will shift from smaller more inefficient facilities to new facilities if other sources of methanol are not found.

Table 4.2 shows the number of methanol production facilities in China grouped by region and feedstock by end of 2018, excluding the CTO integrated facilities. Most facilities use coal as a feedstock with only 16 facilities operating on natural gas. Coal based facilities fall into several categories. Coal is either the primary feedstock or it is co-fed with natural gas. Coke oven gas also provides a feedstock that is a co-product from steel production. Some methanol plants are also configured to produce either ammonia or methanol depending up on the market conditions for either product.

Table 4.2. Methanol Production Facilities in China

China Region	Coal	Natural Gas	Natural Gas/ Coal	NG/ Coke Oven	Coke Oven Gas	Coal/ Coke Oven Gas	Coal/ Ammonia	Total[a]
East	10	2	0	0	16	1	15	44
North	4	0	0	0	22	0	9	35
Northwest	16	6	0	0	13	0	11	46
Southwest	5	5	1	1	1	1	4	18
Northeast	3	2	0	0	9	0	1	15
South	0	1	0	0	0	0	2	3
Central	6	0	0	0	1	0	15	22
Total Plants	**44**	**16**	**1**	**1**	**62**	**2**	**57**	**183**
Capacity (MTPA)	**18.77**	**6.84**	**0.45**	**0.5**	**10.59**	**1.71**	**20.55**	**59.4**

Source: ASIACHEM, 2018

[a] excludes dedicated coal to olefin facilities. 42 plants over 500 k tonnes/year

The production capacity grouped by region is shown in Figure 4.2. A significant portion of China's methanol production capacity is located in northwest China including Inner Mongolia, which has abundant coal resources. This source of methanol is a leading supplier to East China MTO plants. Methanol is delivered by truck or truck and barge to East China because infrastructure for other routes such as rail is either not available or well developed (ASIACHEM, 2018).

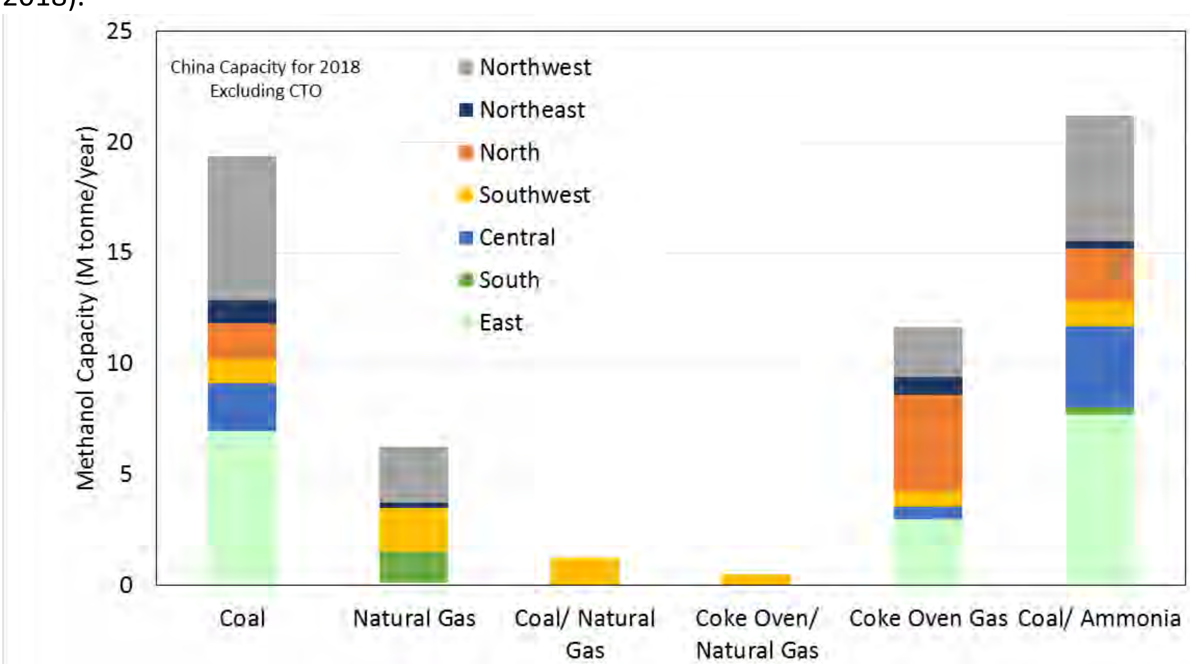

Figure 4.2. Chinese Methanol Production Capacity by Region and Feedstock.

Figure 4.3 shows the methanol production capacity in different regions in China and the transport distance to Bohai Tianjin. The capacity combined with feedstock and transport costs based on location of facilities provides the basis for estimating delivered costs to Bohai Tianjin, China which are examined in Section 4.4. The current flow of methanol from Inner Mongolia in the Northwest Region to Tianjin in North China occurs today by truck. Significant methanol also moves from Shaanxi in Northwest China to Nanjing in East China by truck and barge along the Yangtze River (ASIACHEM, 2018).

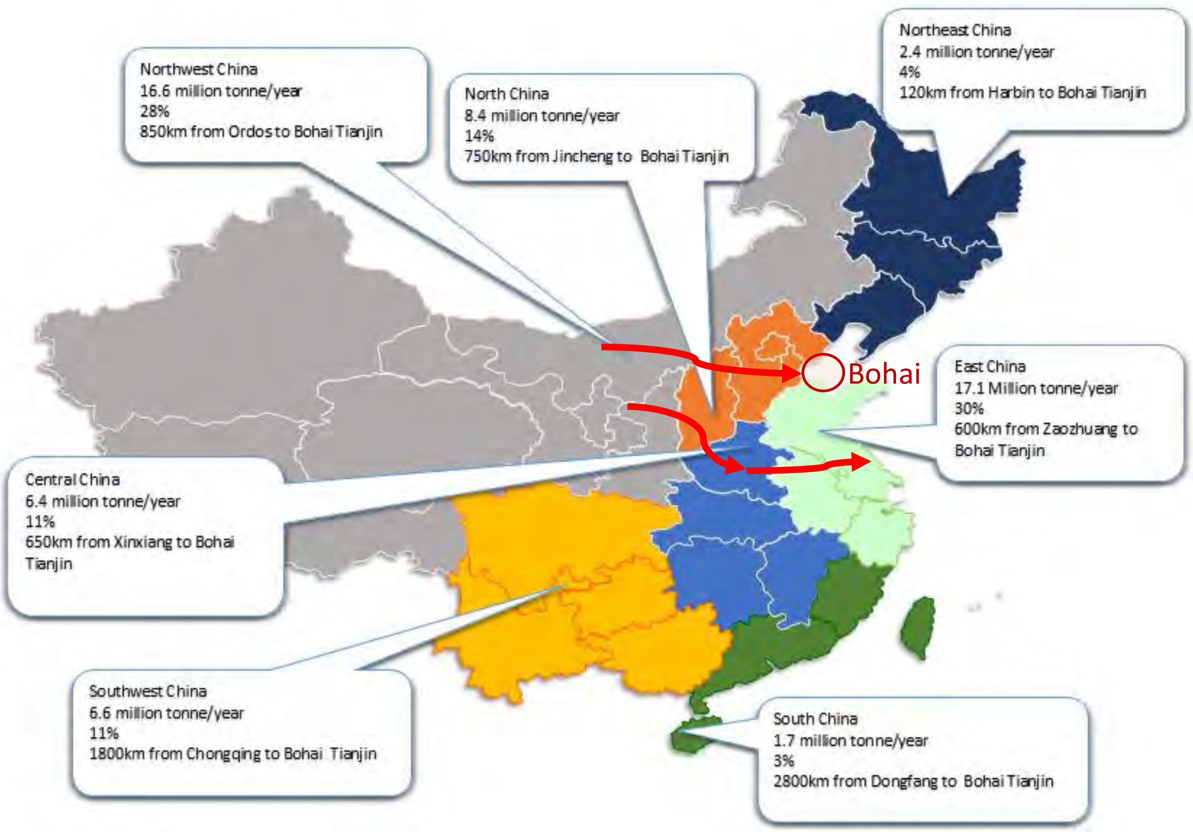

Figure 4.3. Chinese Methanol Production Capacity and Distance to, Bohai Tianjin, China and delivery flow shown in red.

4.2.3 Methanol Imports to China

China has been a net importer of methanol for over a decade. Figure 4.4 shows the sources of imported methanol to China. The primary sources are producers with access to low cost feedstock and relatively short transport distance to China including Iran, Saudi Arabia and other Middle East producers, Malaysia and New Zealand (Simoes, 2011). The mix of producers has not changed significantly over the past 10 years with imports ranging from 3 to 8 MTPA (ICIS Analytics & Consulting, 2017). More imports to China have not occurred due to limitations on global methanol capacity as well as the transition time it takes for more cost-efficient producers to enter the market.

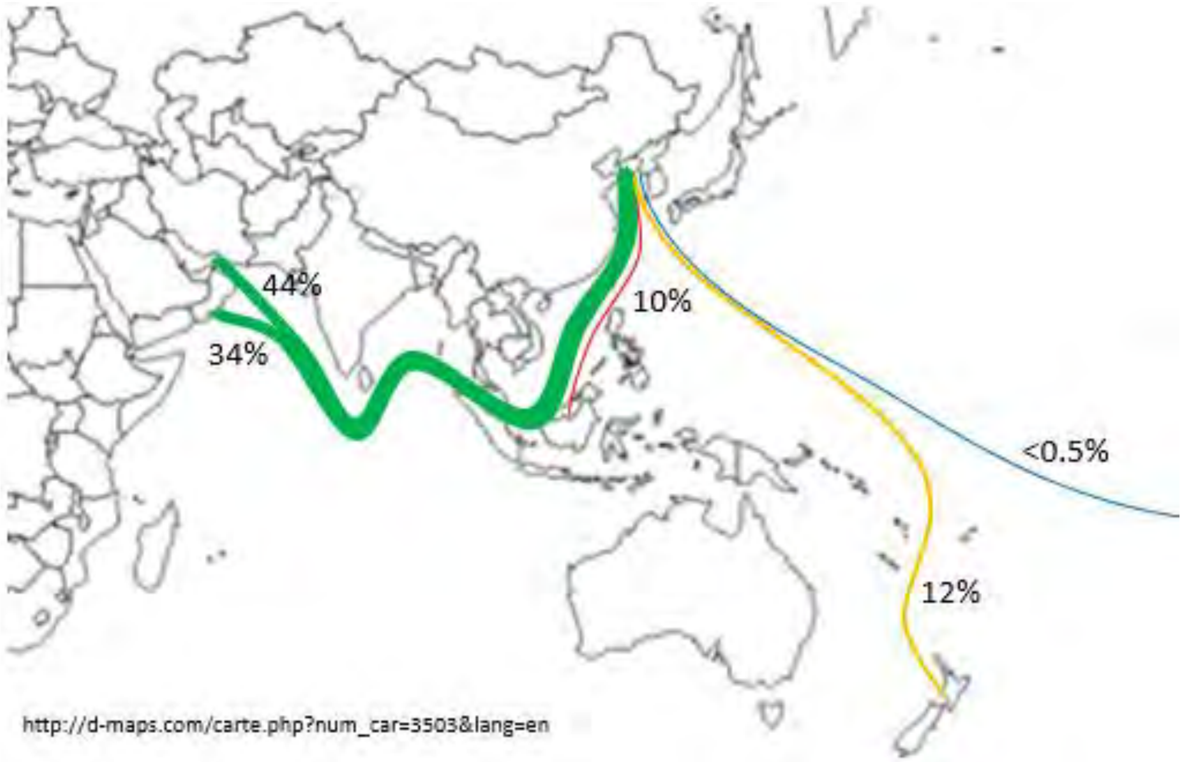

Figure 4.4. Source of methanol imports to China in 2015.
Source: (Simoes & Hidalgo, 2011) https://atlas.media.mit.edu/en/profile/hs07/290511/

4.3 Methanol and End Product Demand

Methanol is used in many chemical and fuel applications globally. It is used as a solvent, industrial chemical, and input for fuels. The uses of methanol in all of these applications is growing globally. The effect of KMMEF methanol on these markets is discussed below.

4.3.1 Uses of Methanol

Methanol is an input for many industrial processes as shown in Figure 4.5. Historically, methanol was an input for formaldehyde and acetic acid production as well as the primary component in many solvents. Formaldehyde is a precursor to many chemical compounds and materials including resins used in manufacturing of plywood and other materials. Demand for methanol grew with the introduction of methyl tertiary butyl ether (MTBE) in the 1990s. More recently methanol to olefins (MTO) has grown as a use for methanol. Global methanol demand has grown from 9 to 10% per year over the past 10 years. The Department of Energy's Energy Information Agency (EIA) and others project a continued growth in demand for the foreseeable future in China (Gross, 2017) as well as globally (Alvarado, 2016).

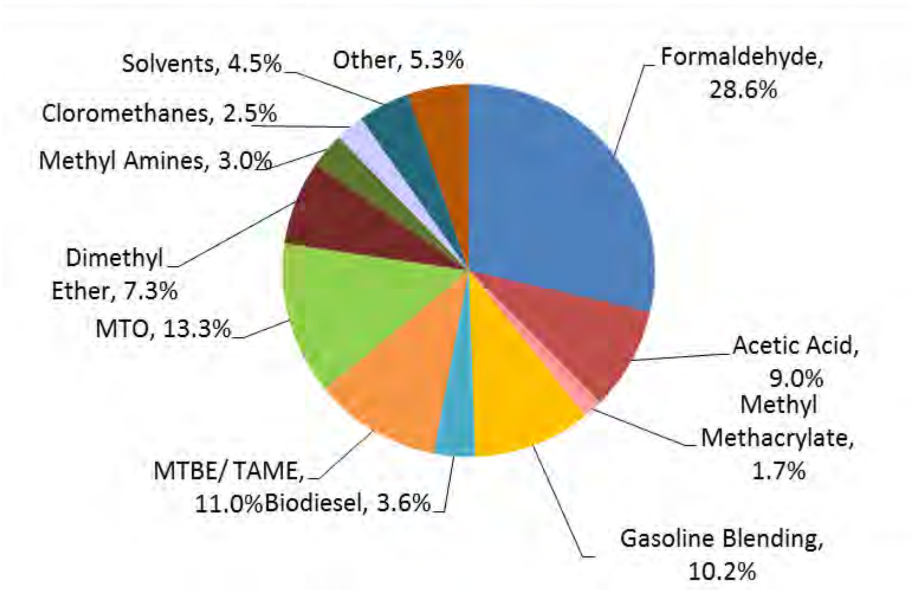

Figure 4.5. Global Uses for Methanol in 2016
Source: (Alvarado, 2016; Bann, 2015)

4.3.2 Methanol Demand

Methanol is transported as a global commodity. Shipments flow from regions with low cost feedstock and low-cost methanol to regions of methanol demand. Demand for methanol has more than doubled in the past ten years. Figure 4.6 shows the rapid growth in Chinese methanol consumption by end use from 2005 to 2017. The following sections examine the effect of fuel markets on the supply of methanol in China.

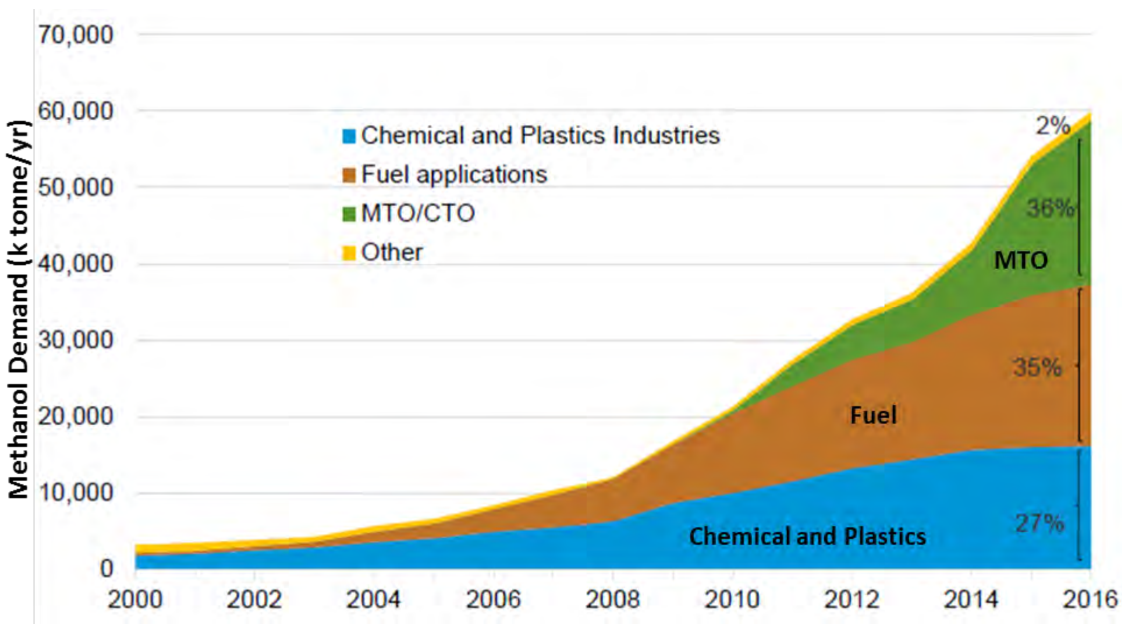

Figure 4.6. Methanol Demand in China.
Source: (Gross, 2017)

4.3.3 Methanol to Olefins (MTO)

MTO is the enabling market for the KMMEF. NWIW intends to ship all of the KMMEF methanol produced to China for MTO production. MTO involves the dehydration of methanol to form olefins. Olefins are a key component in materials production. Since China is a leader in manufacturing consumer goods, a reliable source of olefins is essential. There are 7 operational or under construction MTO plants with another 10 planned and under construction MTO projects in eastern China and along the Yangtzee River (ASIACHEM, 2018).

The MTO production capacity in China has grown from zero in 2010 to 10 million tonne/year of MTO today (Alvarado, 2017). CTO plants produce methanol as an intermediate product though they have the capacity to import methanol also. The next category is MTO plants that are set up to use China coal-based methanol resources due to their geographic proximity to coal producing regions. The final category of MTO plants are located in East China where they are situated to receive both imported methanol and domestic coal-based Chinese supply. The total capacity of existing MTO plants in East China with access to imported methanol is 8.2 million tonnes/year with a planned expansion of 7.5 million tonnes/year (ASIACHEM, 2018).

The 4 operating MTO plants in East China consumed about 4.4 million tonnes of imported methanol in 2017 representing approximately 53.3% of the feedstock required to achieve full production. Domestically produced coal-based methanol to realize a higher production rate. East China MTO plants are operational and will continue to meet a portion of the demand for olefins in China.

Methanol sources for East China MTO facilities are driven by two forces:

A. East China methanol plants will import methanol when transport costs from Inner Mongolia are too high.
B. East China methanol plants must pay the market price for methanol landed in China. If methanol flows from Western to Eastern China exceed the expected market price, imported methanol will provide the low-cost option.

Since methanol in China is a fungible commodity and MTO facilities face paying the market price for methanol, imported methanol will continue to displace domestic methanol as long as MTO facilities continue to operate and supply the growing China olefin industry as illustrated in Figure 4.6. Projections from Mitsubishi, IHS, and others show the demand for olefins in China will continue to grow into the foreseeable future. This projection indicates that MTO will continue its robust growth and increasing olefins market share.

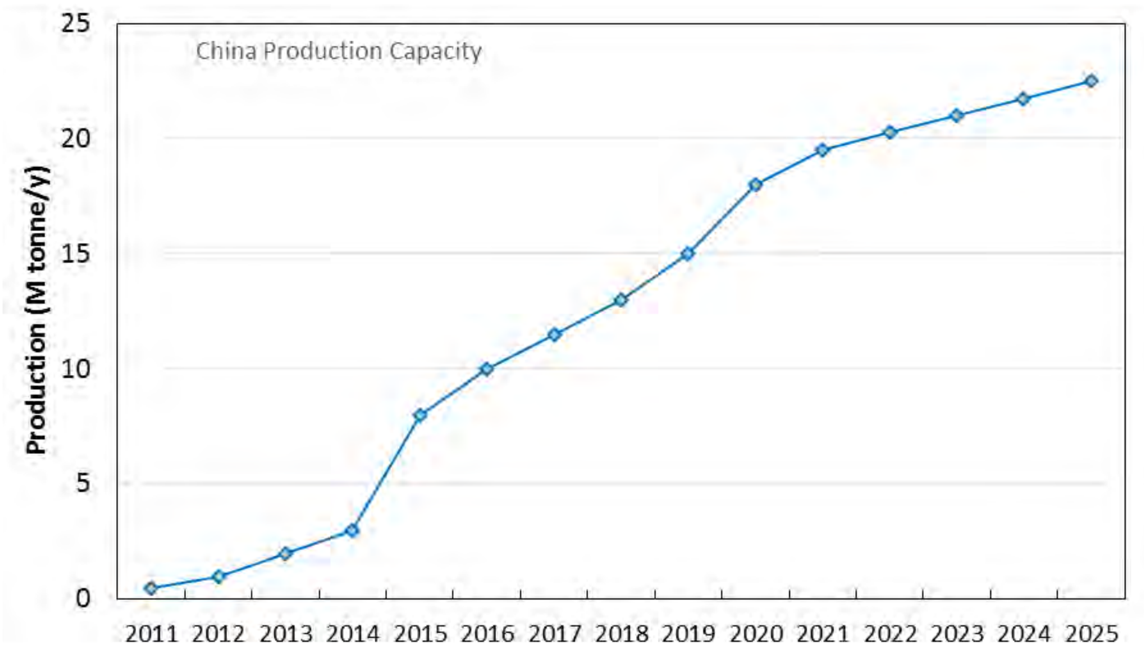

Figure 4.7. MTO Capacity in China.
*Source: (*Alvarado, 2017, Mitsubishi, 2017)

4.3.4 Other Sources of Olefins

Other sources for olefin production are also options in China. Leading olefin production routes are shown in Figure 4.8. Oil refineries have historically been the primary source of olefin feedstock in China. Propylene is a by-product of fluid catalytic crackers (FCC). Olefins are also produced through steam cracking of light hydrocarbons such as ethane, propane and butane or heavier components such as refinery naphtha, which consists of a range of C4 to C7 hydrocarbons. These sources of olefins are limited to global oil refining capacity and the ability to recover olefins and ship them to market. Naphtha remains the predominant feedstock for Chinese olefin production, but its relative market share continues to decline due to rapid MTO growth.

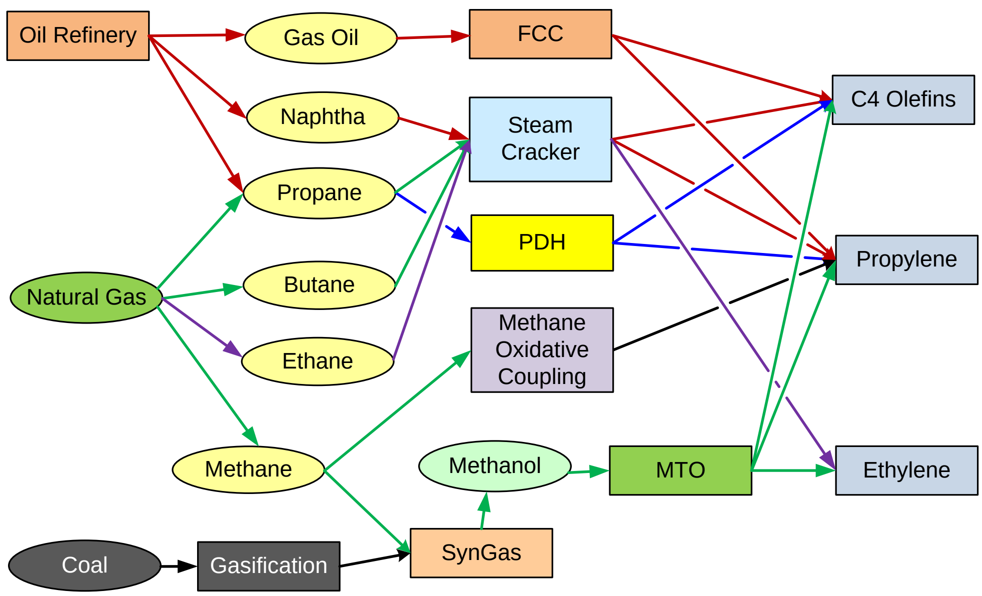

Figure 4.8. Olefin production routes are based on various petroleum feedstocks.

Steam crackers in China are largely run on imported product from oil refineries. The economics of steam cracking depend on petroleum prices and naphtha crackers will be more economical at lower petroleum prices. Another source of olefins feedstock is natural gas derived ethane which is then cracked into ethylene. This resource is plentiful in the U.S. but very constrained in China. Neither ethylene nor ethane is readily transported long distances.

The fact that China remains a leader in manufacturing indicates that demand for olefins will continue to grow. Based on historical trends and existing capacity, MTO will provide at least 10% of China's olefin market. At higher oil prices, MTO will become more economically attractive and facilities should operate at greater capacity (Zinger, 2016). The capacity of the KMMEF is about 18% of the MTO market and about 2% of the total China olefins demand by 2022.

MTO producers in Eastern China require a steady supply of methanol to meet the current and future demand from the materials industry for their product. Methanol price, availability, and reliability are key determinants for where olefin producers contract their feedstocks. As previously discussed, the Eastern China MTO plants primarily rely on domestically produced methanol from Western China and imports. This Chinese produced methanol is primarily coal based and carries high costs for delivery to the Eastern China MTO facilities.

For methanol to be a desired input for Eastern China olefin production, it must have expected costs lower than alternative input sources (i.e., coal, naphtha, oil gas, etc.) and it must be continuously available at the olefin plant gate. Natural gas-based methanol can meet these criteria and is thus desirable for olefin production. The ability to meet Eastern China methanol input needs with imported natural gas-based methanol allows olefin producers to avoid the higher cost methanol produced from coal in Western China.

Natural gas-based methanol from the U.S. competes directly on delivered price with other imported methanol produced with other feedstocks or in other regions. U.S. natural gas-based methanol also competes, in the long run, with other sources of olefin production. These other sources are impacted by the level of petroleum refining and, as an outcome from that level, the availability of refining byproducts such as naphtha. Crude oil prices directly impact this market and may indirectly impact the availability and price of petroleum-based olefin inputs.

4.3.5 Methanol Fuel Applications

This Study was directed to include an examination of emissions associated with changes in the methanol industry and related markets that may be induced by the KMMEF's methanol production and, specifically, to consider the potential for the project to contribute to market changes that could affect the use of methanol generally as fuel. Methanol is currently used as feedstock in the manufacture of products used as fuels such as DME, biodiesel and MTBE. It also can be converted into gasoline via the methanol to gasoline (MTG) process. Methanol is also blended into gasoline or used as an alternative to coal in domestic boilers or for cooking stoves. DME produced from methanol is used for cooking fuel where it replaces coal for home cooking (Larson & Yang, 2004). About 50% of fuel methanol is used in DME applications where it is used for cooking and displaces fuels such as coal. About 1/3 of the fuel applications are for vehicle fuel applications with the balance uses as directly as cooking or boiler fuel (Argus 2018).

China's Thirteenth five-year plan (2016 to 2020) states that low-carbon development will be viewed as an important driving force for economic improvement. One consequence of this initiative has been the drive to shut down small coal fired boilers and to reduce the dependency on coal for cooking. Methanol and imported natural gas either by pipeline or as LNG are playing an important role in the process of delivering clean burning fuels to reduce CO, PM, NO_x and SO_x locally.

Methanol's properties allow for its use as a transportation fuel. Methanol has an octane number (R+M)/2 of 100, which makes it attractive for spark ignition engines. Methanol is also a precursor for the production of other fuels. Methanol is used as a fuel in the following applications:

- Low level blends (M5, M10, M15)
- High level blends (M85, M100)
- Feedstock for methyl-tertiary butyl ether (MTBE), methanol to gasoline (MTG) and DME
- Direct methanol fuel cell

China is a global leader in methanol fuel, with numerous provinces developing methanol fuel standards ranging from M5 (5% methanol, 95% gasoline) to M100. Similar initiatives are underway on the national level, where China has adopted M85 and M100 standards and is currently evaluating a potential M15 national fuel standard.

Figure 4.9 shows the history of methanol fuel use in China. In addition to transportation applications, about 18% of methanol fuel is used for stationary applications where it displaces coal with the aim of reducing air pollution.

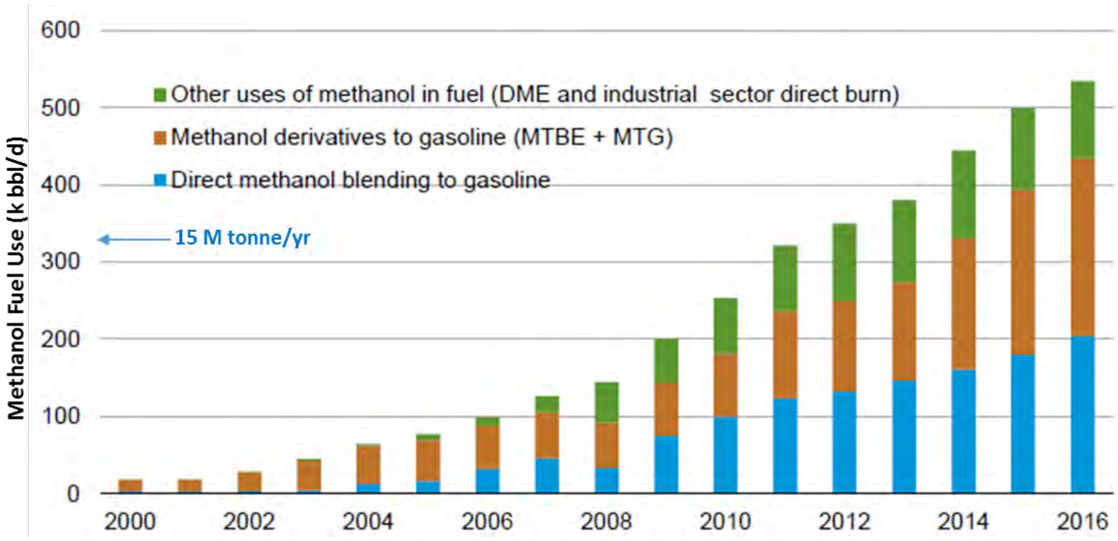

Figure 4.9. Uses of Fuel Methanol in China
Source: (Gross, 2017)

The potential for the KMMEF to contribute to market changes that could affect the use of methanol generally as fuel are minimal as the KMMEF will expand global methanol capacity by only 3%. End use demand for methanol as fuel is dictated by substantial primary market effects including the price of crude oil and gasoline, and consumer behavior. Similar effects drive fuel choices for home heating and industrial applications. The response of fuel use to economic factors has been extensively examined in the literature including China - specific analyses (Arzaghi & Squalli, 2015; Lin & Zeng, 2013).

Given the response of consumer demand to price, a new source of methanol will not impact end user demand or induce methanol-as-fuel market changes other than through secondary market effects which are not of quantifiable significance. The GHG emissions of methanol uses as a fuel are examined in Section 5.5 for the various fuel applications described here even though the overall displacement is small.

4.3.6 Methanol Market Demand Summary

Methanol use in China has grown from 2 to 3 MTPA in 2000 to over 60 MTPA today, driven by solid growth in its traditional chemicals markets, increasing fuel applications and, a very substantial growth in the MTO market. The first MTO facility was built in 2010 as new technology. Since then MTO facilities have grown to comprise 36% of China's entire methanol demand. Most of this demand has been met through the development of coal to methanol facilities although more recently low-cost gas-based imports have begun capturing market share.

Nevertheless, 16 new coal to methanol facilities, representing 12 MTPA of capacity, are expected to come into operation between 2018 and 2023 in the absence of a reliable source of imported natural gas-based supply (ASIACHEM, 2018). Currently and into the foreseeable future, the demand for methanol will grow at such a pace that China coal-based facilities will continue to operate unless additional new supplies are made available.

4.4 Methanol Production Cost

The marginal methanol producer supplying product to East China is based on the cash cost of delivery to this region. The cost inputs include feedstock, operation and maintenance and transport to East China.

4.4.1 Feedstock Cost

Feedstock cost depends on regional supply and demand. Global energy prices affect both coal and natural gas since coal is traded as a commodity. Natural gas prices are determined more regionally but are affected by the ability to convert natural gas to LNG as well as the substitute value of natural gas versus liquefied petroleum gas at oil refineries.

Natural Gas Feedstock

Regional natural gas prices are discussed in Section 2.4.8. In North America gas costs have dropped substantially as the shale gas "revolution" has unfolded, abundant supplies suggest the trend in natural gas prices will remain flat for the foreseeable future. This is reflected by the natural gas prices in Figure 4.10. The greatest contribution to the increase in natural gas production has been through the development of shale and tight sand formations.

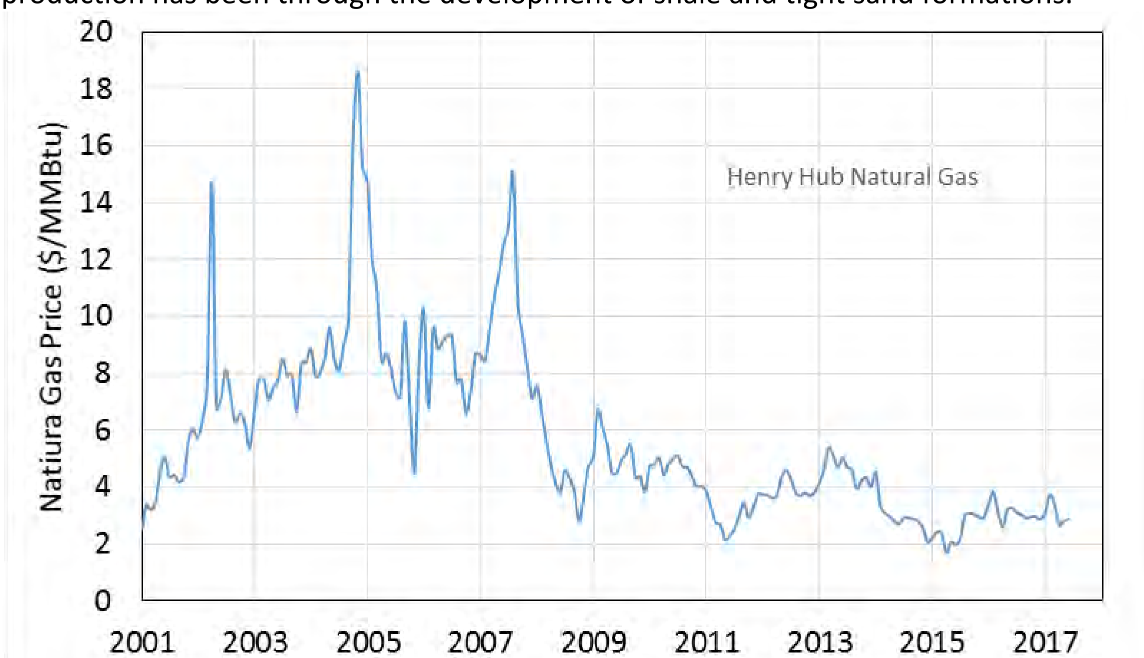

Figure 4.10. Natural gas prices have declined over the past decades due to the introduction of new production technologies. The Henry Hub price is the U.S. Benchmark.
Source: (EIA, 2018c)

These increases have been seen not only in traditional gas production areas such as Texas, Louisiana, British Columbia and Alberta, but also non-traditional places such as Pennsylvania and Arkansas.

Coal Feedstock

The cost of coal in China varies by region and coal quality. The range in coal prices is shown in Figure 4.11. The lowest cost coal occurs in the western regions of Inner Mongolia and around Shaanxi. The price is substantially higher in East China, which is further from coal production regions. Coal prices have shown significant volatility in the two years shown. The variation appears to be in part in response to volatility in global energy prices.

The average of the coal prices in Figure 4.11 provides the basis for estimating the feedstock cost for coal by region in China. This result is consistent with a case study analysis of coal to methanol for Guanzhong, Shaanxi in a study by the Asian market research firm ASIACHEM (2018).

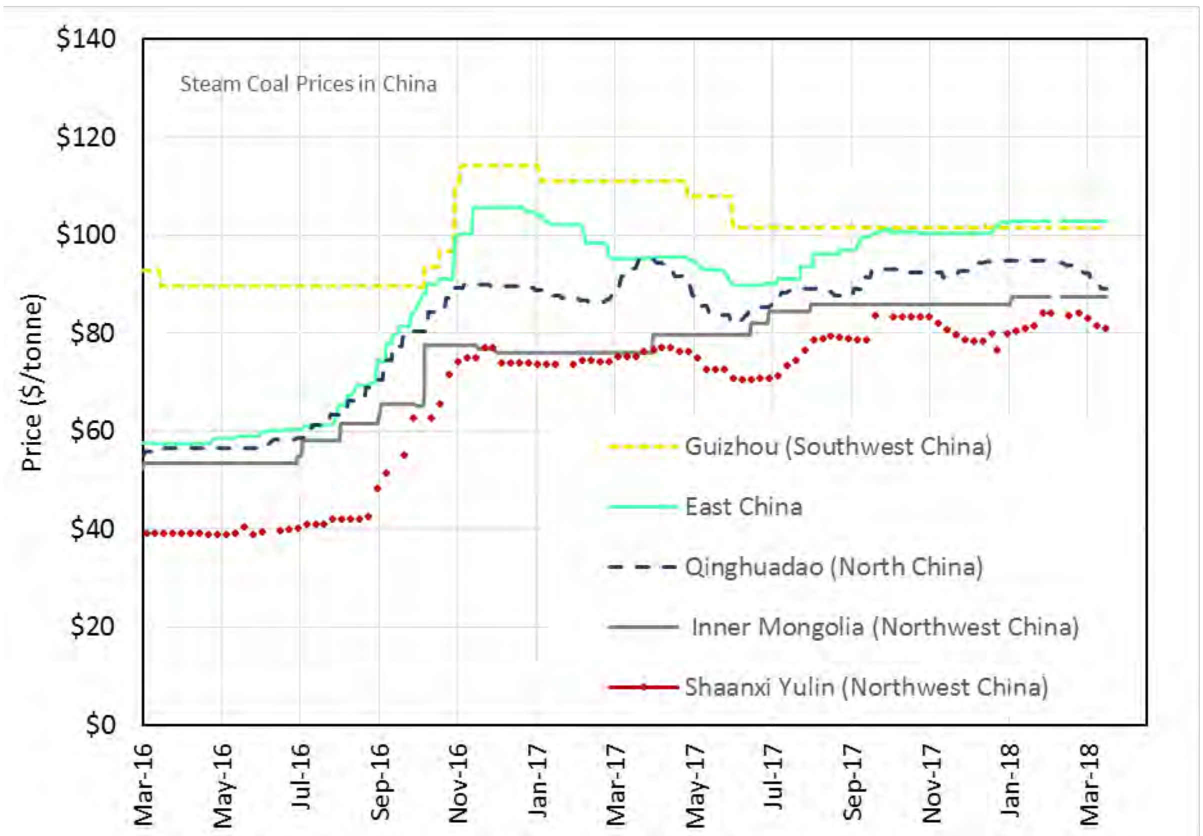

Figure 4.11. Coal Price in China by Region.
Source: (Windfield Database)

Feedstock and Electricity Cost

Feedstock costs were estimated based on the methanol plant technologies described in Section 2.4.1 and feedstock costs in Section 2.4.8. For natural gas-based plants, the feedstock cost is based on the natural gas to methanol yield combined with the feedstock price. For coal-based plants, the feedstock costs include the feedstock coal to methanol yield as well as the steam coal input. The coal feedstock costs correspond to the average regional prices in Figure 4.11. The cost of steam coal that is used to generate steam and power is assumed to be 92.3% of that for gasification coal (ASIACHEM, 2018). For facilities that operate on coke oven gas, the feedstock is the by-product of steel production. However, the gas still has value based on its energy. The feedstock costs for these facilities is estimated to be 83.6% of the cost of coal feedstock based on the life cycle energy inputs in a study on methanol from coke oven gas (Li et al., 2018). For technologies that use imported power, the power use rate combined with the local price of power is included as a cost.

4.4.2 Operation and Maintenance Cost

Operating costs include labor, chemicals, maintenance supplies, and overhead. Operating costs $C_{O\&M}$ were estimated based on the methanol production technology and plant capacity based the following relationship:

$$C_{O\&M}(M) = C_{OB} \, (M/M_B)^n \qquad (5)$$

Where:

C_{OB} = Operating cost for baseline capacity
M = Annual production capacity
M_B = Baseline plant annual production capacity
n = Scaling exponent = -0.2

The operating cost for each methanol plant with access to East China is based on the power function in the above equation to take into account the economies of scale for each facility[21]. Smaller facilities have higher operating costs per tonne and facilities larger than the baseline have lower operating costs per tonne.

4.4.3 Transport Cost

Transport costs depend on the transportation model, fuel cost, distance, operating cost, and tolls. Methanol transport to East China occurs via marine transport from international sources such as the KMMEF and by truck and barge within China.

Marine transport costs are provided in Section 2.4.6. These costs take into account tanker capacity, distance to East China, and Panama Canal tolls if applicable.

[21] A scaling exponent of -0.2 is comparable to an annual cost scaling factor of 0.8 when cost is divided by throughput to represent cost per tonne. A discussion of scaling factors are found in several economic references (Moore, 1959, Tribe 1986) (Couper, 2003).

Transport costs within China are based on a bottom up analysis of fuel, labor, and tolls discussed in Section 2.4.6, which is consistent with an analysis performed by (ASIACHEM, 2018). The transport costs for each region in China are calculated as a function of distance to East China.

4.4.4 Cash Cost of Production

The methanol plants from Tables 4.1 and 4.2 were screened to identify facilities with potential market access to Bohai Tianjin. Facilities with known off-take arrangements as well as those with transportation distances that would make delivery to Bohai Tianjin uneconomical were removed from the inventory. The methanol production capacity from these plants was also removed from the overall China demand.

Table 4.3 shows the calculation of cash cost for a coal to methanol plant. The feedstock costs per tonne of methanol are based on the coal use rate combined with coal costs from Section 2.10. For other coal production facilities, operating costs are scaled in proportion to capacity, transport costs are determined as a function of distance to Bohai Tianjin. Coal prices are based on regional prices. Operating costs include labor, chemicals and consumables, and a small amount of sulfur sales. Additional examples of the cost analysis are shown in Appendix C. The most significant factors affecting production costs are feedstock cost and scale.

Table 4.3. Cash Cost of Production for Coal to Methanol Plant

Facility Type:	Coal Gasification		300	k tonne/year
Location:	Shaanxi			
Cost Inputs	**Feed[a]**	**Use Rate**		**Cost**
Feedstock Coal	$76.2	1.68	t/t	$128.0
Steam Coal	$70.3	0.3335	t/t	$45.0
Power	0.066	288	kWh/t	$19.0
O&M				$68.9
Transport				$60.7
Total Cash Cost				$321.7

[a] Compare with ASIACHEM, 2018 Table 2.4, $77.69/tonne for gasification coal
600 ktpa = cash cost from ASIACHEM is $309.4/tonne. For 600 ktpa, Total for Table 4.3 would be $312/tonne

4.5 Marginal Impact of KMMEF Methanol

KMMEF methanol provides an opportunity to meet a growing demand for MTO, primarily in China.

4.5.1 Methanol Supply Curve

The research team developed an inventory of the global methanol production capacity. Figure 4.12 depicts individual plant capacity and cumulative capacity based on the inventory of global methanol plants assembled by the Study team. The columns are color coded by region, allowing readers to recognize patterns in methanol capacity by geographic region of the world. The graph contains two axes. The left axis is scaled to individual plant capacity, up to 6 million tonnes. The right axis represents the cumulative capacities with maximum value 120 million tonnes. Smaller plants dominate the population, 50% of methanol plants represent less than 20% of total capacity.

In order to establish a supply curve of facilities that do not compete in the open market were eliminated from the supply. Examples include facilities that serve a local market such as small natural gas to methanol facilities in western China.

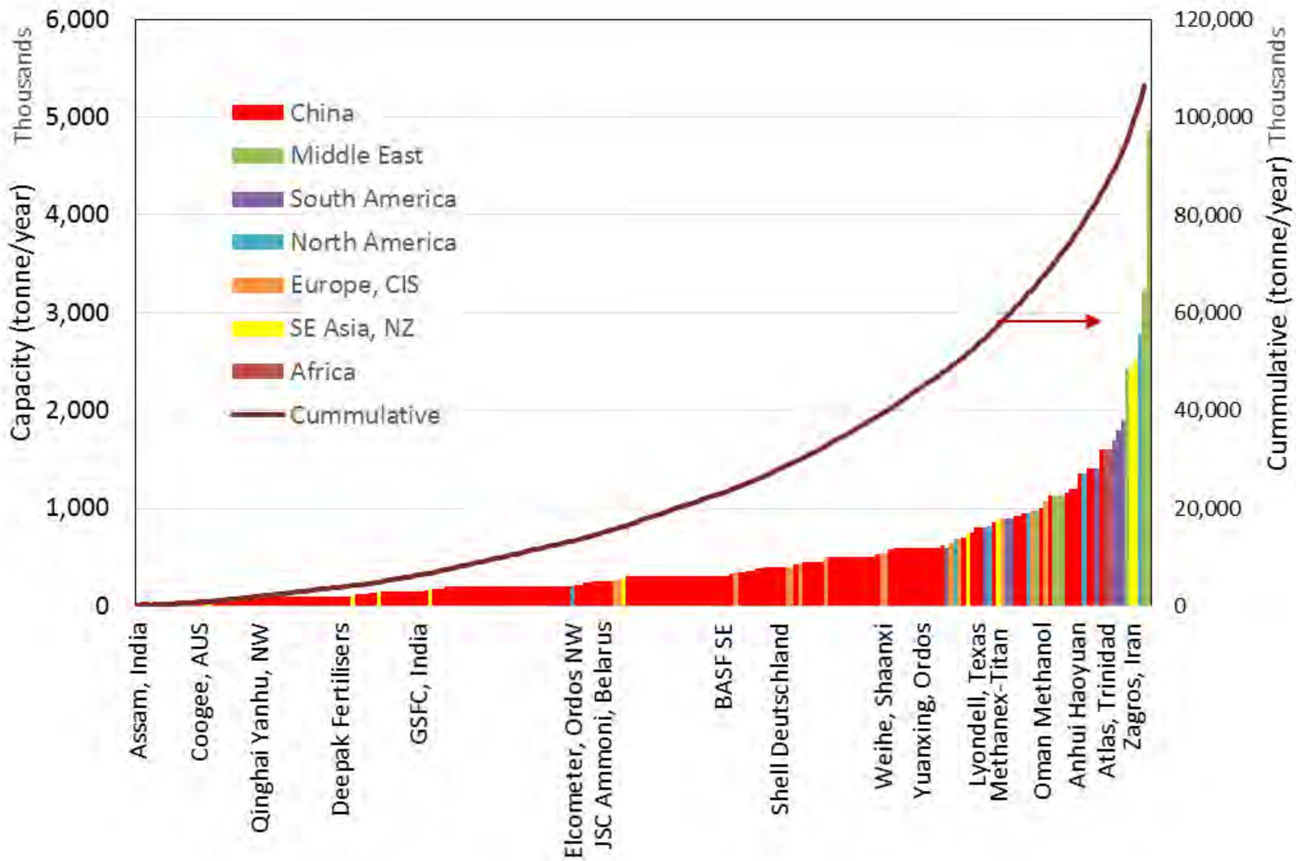

Figure 4.12. Global Methanol Producers by Region with Select Plants Identified.
Source: Methanex, ASIACHEM, web sites for methanol producers, Methanol Institute

The global methanol producers with access to China were arranged in order of cost and were based on the list of global methanol capacity in Figure 4.12. Feedstock, operating, and transport costs discussed in Section 4.4 provide the basis for determining the cash cost including transport to Bohai Tianjin, China.

Figure 4.13 shows the inventory of methanol plants grouped by production capacity. As indicated capacity associated with smaller methanol plants exists largely in China. A significant portion of the world’s methanol production capacity is from larger natural gas-based plants in the Middle East, South East Asia, New Zealand, and Trinidad. These sources are the leading importers to China (Simoes & Hidalgo, 2011).

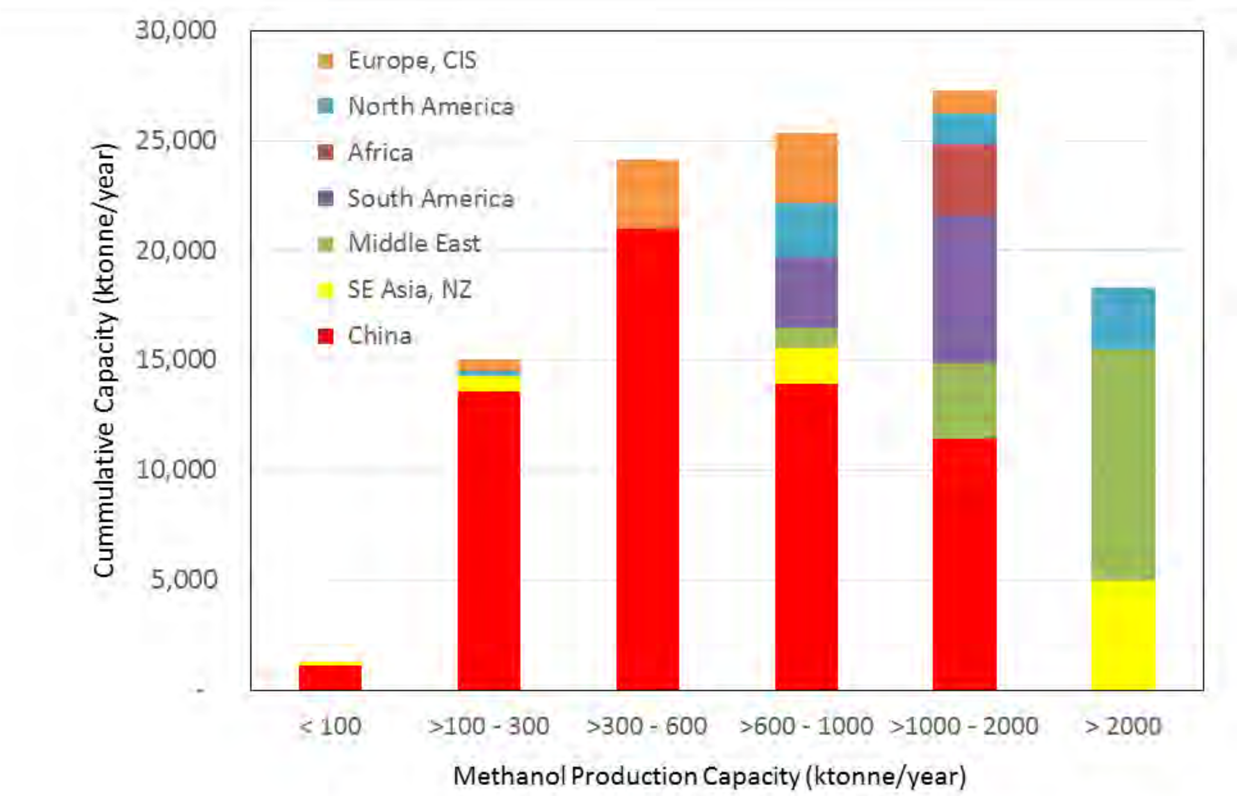

Figure 4.13. Inventory of Current Methanol Production Capacity by Region.
Source: Methanex, ASIACHEM, web sites for methanol producers, Methanol Institute

The lowest cost producers are merchant natural gas-based facilities with low cost feedstock. Facilities with no potential market access to Bohai Tianjin such as those in Europe or Central Asia were excluded from the inventory of plants. Even if such plants could provide methanol to Bohai Tianjin, the transportation costs would cause them to sell methanol elsewhere. These facilities include about 40 small facilities in China that serve local markets.

China's methanol producers affect world prices, shown in Figure 4.14, since production costs are generally higher than those of international natural gas-based plants. The operation of methanol facilities depends on the market price of methanol as well as the local economics of the end use. For example, local prices have varied from 1900 to 2350 yuan ($325 to $392) per tonne in a 2016 market report. (Shanxi Fenwei Energy Information Services Co., 2018). The analysis from ASIACHEM shows that methanol delivered to East China costs $309/tonne which is consistent with the analysis in this Study.

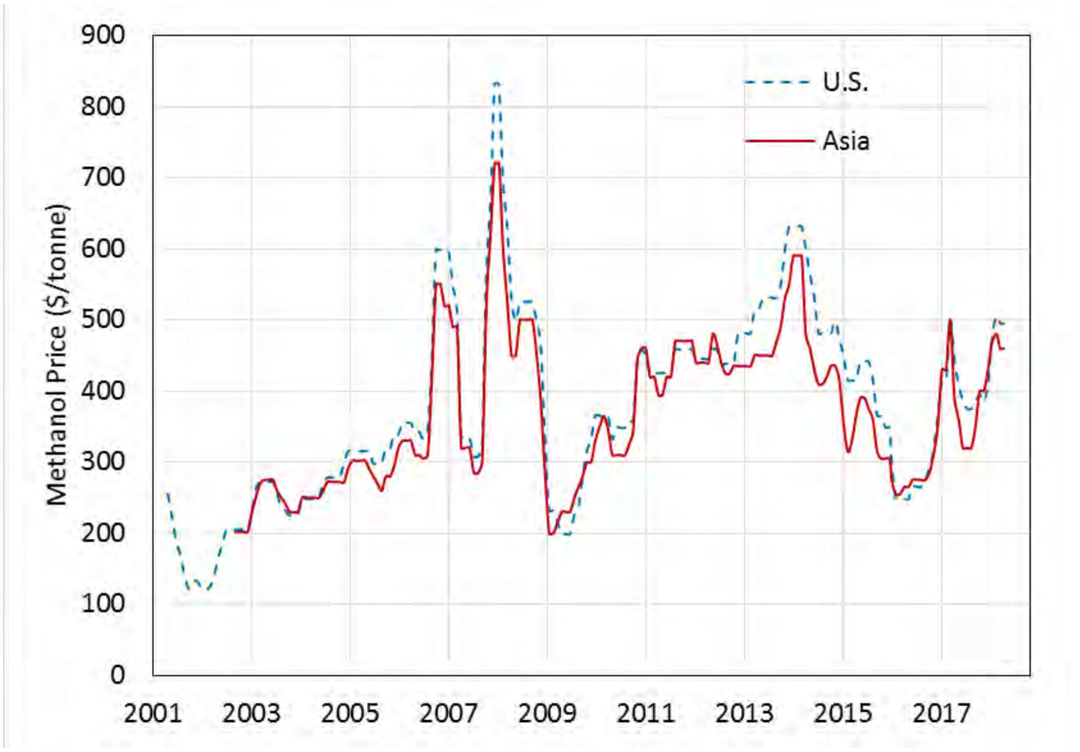

Figure 4.14. Methanol Price History.
Source: Methanex

Figure 4.15 shows the global supply curve of methanol plants on a cash cost basis. This curve was developed from the feedstock costs in Section 4.4.1, feedstock to methanol yields and imported power in Section 2.4.1. O&M costs are a function of plant capacity and transport distance reflects the distance to basis for delivery to Bohai Tianjin China. Some natural gas-based facilities in China serve dedicated local customers. With the high cost of natural gas (over $12/mmBtu), these facilities do not effectively compete. This cost curve, while independently generated, is consistent with curves develop in other studies (Alvarado, 2017; Wirawan, 2011).

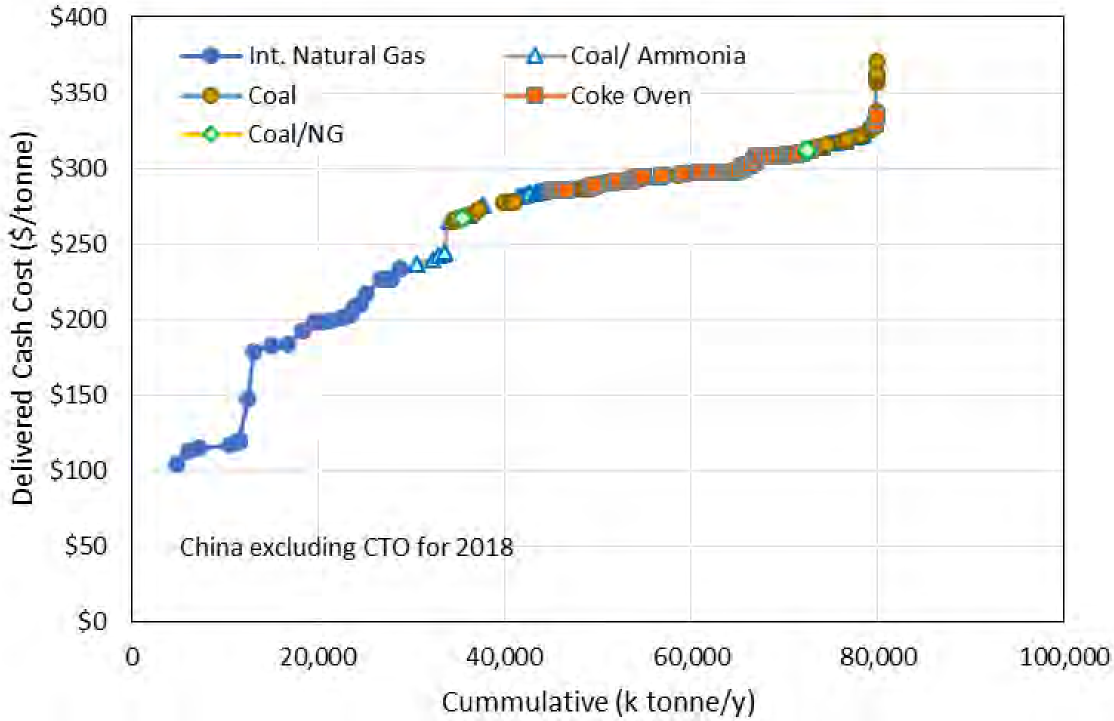

Figure 4.15. Global methanol supply with access to China excluding facilities with captive markets.

The inventory of methanol plants was then adjusted to eliminate facilities that would not deliver to Eastern China or be affected by a new source of methanol from the KMMEF. Figure 4.16 shows the supply curve of methanol plants meeting the demand for methanol in China. This curve reflects the 30% excess capacity of methanol plants in China and includes an estimate of the excess capacity of international natural gas-based facilities. China methanol plants that are based on coke oven gas are excluded from both the supply and demand part of the analysis as the operation of these facilities depends on the economics of steel production. The supply of international natural gas based methanol is consistent with the methanol that has historically been imported to China such that the supply curve is consistent with the demand.

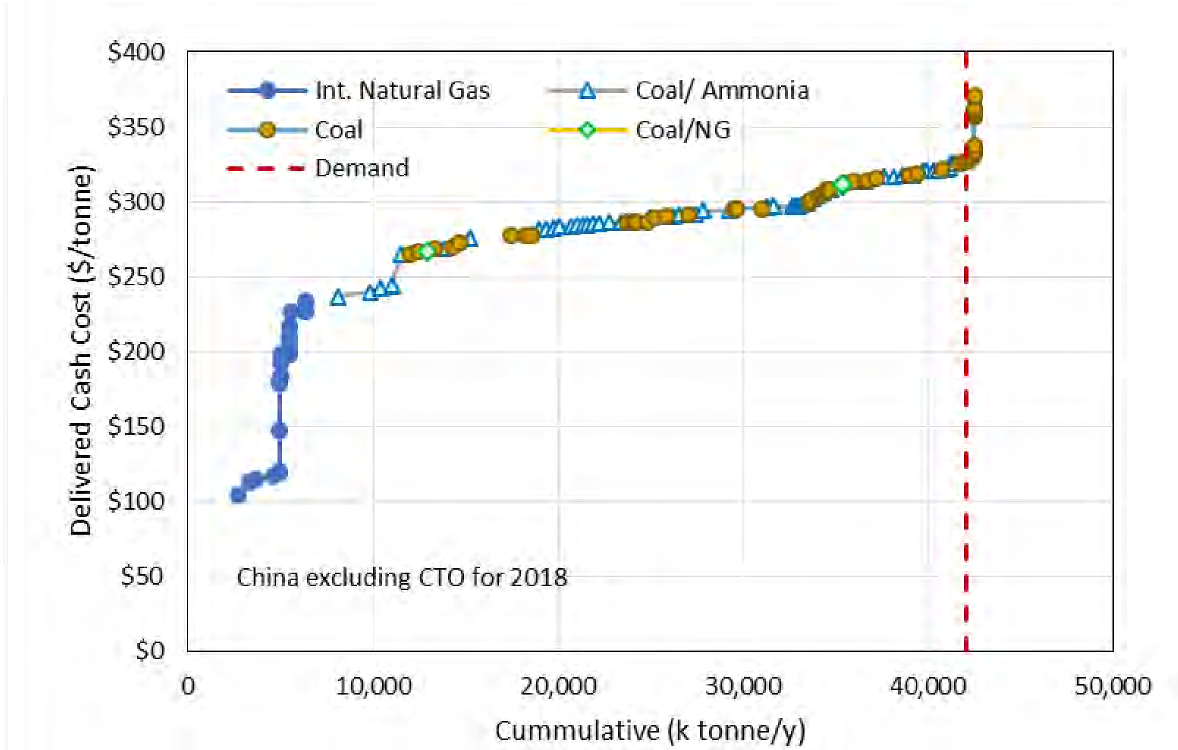

Figure 4.16. Supply curve of methanol producers that can access China MTO markets

Figure 4.17 shows the prior supply curve with the additional capacity from the KMMEF. At a delivered cash cost of $150/tonne, the 3.6 million tonnes per year of capacity shift the competing methanol plants to the right. The marginal plants are located at the intersection of the demand line and the supply curve assuming static demand. The mix of methanol plants on the margin indicates that methanol from the KMMEF will displace the methanol capacity shown immediately to the right of the demand line (see Table 4.5).

The demand for methanol is growing. Developing world scale methanol projects takes time. In the near term, some of the plants KMMEF will displace may continue to operate or enter operation to meet this growing demand until market forces take full effect and KMMEF displaces a combination of existing marginal producers and new CTM plants that fail to be developed.

Assumptions for higher energy prices were applied to the supply curve that determines the marginal resource for displaced methanol. As is the case in the prior scenarios, the usage of natural gas and displacement of other methanol feedstocks are assumed to be insignificant in the long run due to the large availability of natural gas and coal resources.

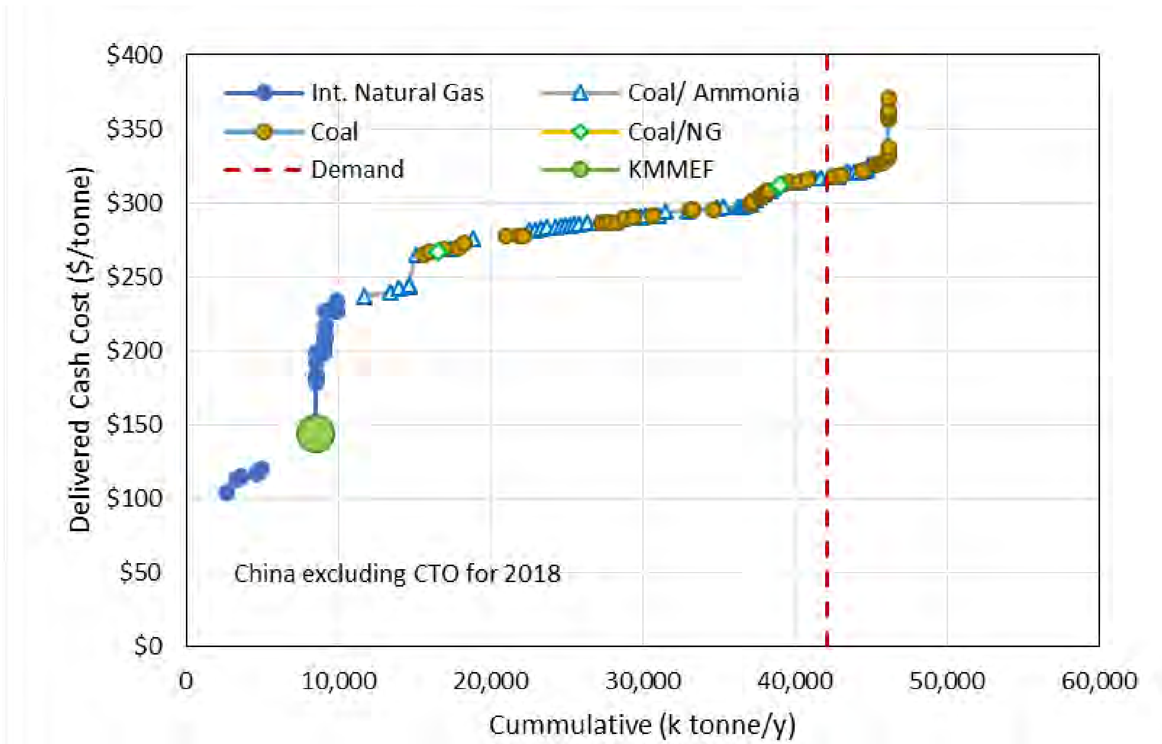

Figure 4.17. Supply curve of methanol producers that can access China MTO markets with KMMEF methanol.

4.5.2 Marginal Methanol Resources

KMMEF will be one of the lower cost producers and the new capacity would shift the supply curve to the right. The output for China methanol facilities and imports to China are shown in Table 4.4 China methanol plants have been reported to run below capacity with the least economical plants operating at the lowest capacity factor. The balance of methanol demand is made up by imports from merchant methanol plants but in the absence of these imports growing to meet anticipated demands, coal-based production will inevitably increase. The China Coal Institute estimates that 4 million tonnes of methanol were imported for MTO in 2016. The projected growth in MTO imports will double by 2021 following the trends identified by IHS (Alvarado, 2017) Therefore, within half a decade import demand for MTO plants will grow to 10 million tonnes per year and total China imports will grow to 15 million tonnes per year as long as these alternative to coal-based facilities come online.

Table 4.4. China Methanol Supply and Demand

Year	Capacity	2016	2021
2016 Capacity	**Factor**	**Capacity**	**Projection**
Coal	78.8%	16..8	28.4
Coal < 200 ktpa	25%	4.5	5.0
Natural Gas	65%	6	6.2
Coke Oven Gas	75%	12.	12.1
Methanol/Ammonia	75%	20.1	21.2
Total		**59.4**	**72.9**

Year	2016	2021
China Production	**42.8**	**52.7**
Total Imports	**8.15**	**15.11**
China Demand	51.0	67.8
Global MTO Demand	10	19.5

Sources: (Alvarado, 2017; Bann, 2015; JLC Network Technologies, 2018; SCI China, 2018)

Producing methanol from coal in China is more expensive than producing it from natural gas in North America. Natural gas prices in North America are lower than in China and most of the world. As shown above, the cost advantages of producing methanol at the KMMEF from natural gas and shipping it efficiently to Asian markets, including China's coastal chemical complexes, will displace methanol production from existing coal-based plants in China and should also discourage development of new coal-based methanol plants. A very large portion of China's increased methanol production is expected to occur in Inner Mongolia near coal mines, which is well inland and requires shipping the methanol to the coast where China's petrochemical facilities are located. Transporting the methanol such long distances overland in China creates additional cost disadvantages for methanol produced from coal. In 2014, almost two-thirds of China's domestically produced methanol for the merchant market came from coal. In 2014, the expanded methanol capacity was mainly from coal-based plants with one natural gas-based exception located in Qinghai. In 2015, the majority of new methanol plants were coal-based plants located in Inner Mongolia. Also, much of China's capacity to produce methanol from coal is in older inefficient facilities with high costs (Alvarado, 2017). Market forces would be expected to drive the methanol market to prefer less expensive methanol manufactured from natural gas over higher cost methanol from coal.

Effect of KMMEF Methanol

When KMMEF methanol enters the world methanol market, the low delivered cost of this supply will displace higher delivered cost product in a stable demand environment. As the methanol market continues to grow, some of this displacement of higher cost existing supply may be mitigated but the continued development of high cost CTM or CTO plants will be reduced. In this market review, the KMMEF methanol supplied to the world market is compared to all other methanol sources within and beyond China's borders. This comparison shows which methanol sources are able and likely to supply methanol to MTO facilities in China. The delivered cost position of KMMEF methanol relative to other suppliers will affect the future structure of the world methanol market.

Table 4.5 shows the marginal methanol plants that would be displaced by 3.6 million tonnes per year of methanol with an overall demand shown in Figure 4.17. The supply curve includes a mix of coal, and coal/ammonia plants. Their ranking on the supply curve depends on the projected operating cost as a function of scale, transport distance to Bohai Tianjin and coal use rate.

Table 4.5. Upstream Emissions from China Coal Production

Type	Number of Plants	Capacity (k tonne/y) Average	Total
Coal > 300 ktpa	1	300	300
Coal < 300 ktpa	2	220	440
Coal Am > 300 ktpa	6	385	2310
Coal Am< 300 ktpa	4	131	525
Total	13	275	3575

The feedstock inputs and transport distances for these facilities provide the basis for the calculation of GHG emissions from displaced methanol in Section 5.

Effect of Feedstock Supply and Demand

As discussed above, the KMMEF will displace the production of 3.6 million tonnes per year of methanol, which would result in the displacement of over 7 million tonnes per year of coal and the increased use of 2.2 million tonnes per year of natural gas. These feedstock displacements have potential effects on energy markets and are examined in the Market Mediated scenario. The macro-economic effect of these displacements would include an effect on coal use with additional supply freed up by the displacement of China coal. Natural gas in Canada would also be affected. Such macro-economic effects are typically examined by a supply price elasticity where the change in consumption is estimated from the elasticity factor combined with the change in price.

The market effect of the KMMEF would include the following:

- Displace methanol plants on the margin
- Market effect of newly available coal in China from displaced methanol plants
- Market effect of new methanol on other methanol markets such as fuel
- Market effect on olefins

The displacement of marginal methanol plants is examined in all of the scenarios. The effect of a new methanol supply and the displacement of existing coal to methanol could affect coal markets absent policies to reduce the use of coal in China and limits on power generation capacity.

An extensive global supply/demand study was conducted as part of the environmental analysis for a coal export terminal (ICF International, 2016). The study examined global supplies of coal and the effect of providing additional coal supply to China. The study examined the effect of providing a new source of coal to China which included the effect of coal supply on global coal prices and price induced demand for coal. The study shows that for 44 million tonnes of coal imported to China, the supply/demand effect was 0 to 2 million tonnes of CO_2e or 45 kg CO_2e/tonne of coal. A similar result is achieved by assuming a 10% price elasticity factor for coal based on the analysis of a supply curve for coal in China (Appendix F.2) which shows a price induced effect of 57 kg CO_2e/tonne of methanol.

A new source of methanol could also affect other methanol markets. Even though KMMEF methanol would be dedicated to MTO, an increase in supply could result in an effect on global prices with an induced effect on the global demand for methanol. One of the significant uses of methanol in China is fuel and this effect is examined in Section 5.5.

Methanol for MTO demand has a potentially significant effect on the displaced methanol. MTO is less competitive with naphtha steam cracking at very low petroleum prices (Zinger, 2016). The situation where methanol to MTO displaces other sources of olefin is examined in Section 5.4.

5. Displaced Emissions

The supply curve of methanol production facilities with access to East China combined with projections for methanol demand examined in Section 4.5.2 identifies the mix of methanol production facilities that would be displaced by the KMMEF. The aggregate feedstock input and transportation distance provide the basis for calculating displaced emissions.

Operational emissions from displaced methanol include the emissions from feedstock production as well as the upstream emissions associated with these inputs. Direct emissions include the on-site emissions from fuel combustion and process emissions. Downstream emissions correspond to methanol transport to the end user. Beyond these downstream emissions, KMMEF methanol and alternative feedstocks and their relative olefin production emissions are compared below. This Study does not specifically analyze the construction emissions from displaced methanol. If global demand continues to grow, additional capacity will be required, and the construction emissions would be comparable or larger than those of the KMMEF[22].

The primary feedstock for displaced methanol identified in Section 4 is coal. The plants that are estimated to be on the margin include a range of production capacities, technology types, and transport distances to Bohai Tianjin[23]. The grouping of emissions is shown in Figure 5.1.

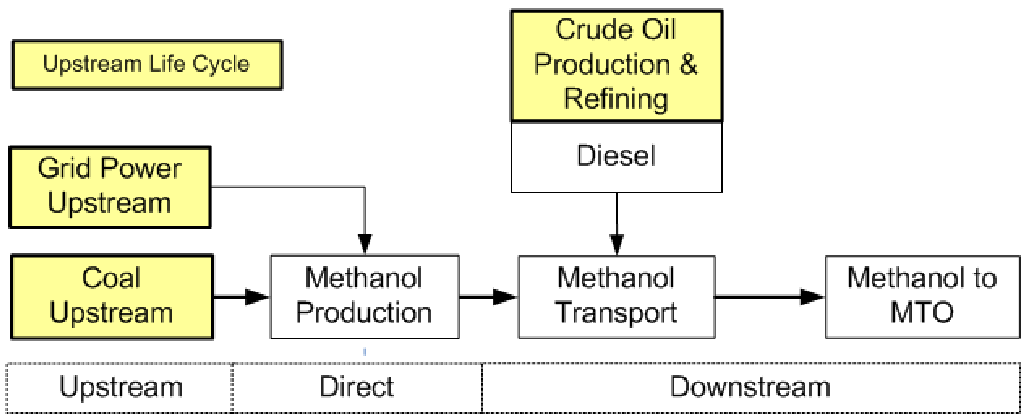

Figure 5.1. Grouping of Life Cycle Coal to Methanol Emissions.

5.1 Upstream Emissions

Upstream emissions from displaced methanol primarily include the emissions for coal production and transport and electric power production. China coal methanol plants generate power for compression and other plant operation requirements on-site. Supplemental electric power is also part of the energy mix for methanol production.

[22] Coal to methanol plants will require a gasifier and solid coal feeding system. The size and complexity is considerably greater than that of a natural gas-based plant; so, material inputs would be greater than those described in Section 3.1.

[23] Transport costs and emissions were modeled on the basis of delivery to Bohai Tianjin, which is representative of East China.

5.1.1 Coal Production

Coal from domestic China resources is the primary feedstock for China-based methanol production facilities. Data on coal production are based on parameters reported for China with diesel fuel and electric power as the primary energy inputs. The assumptions for the emissions from coal production vary with energy intensity, type of energy and coal mine methane (CMM) leakage rates.

The upstream GHG emissions for coal are based on the coal life cycle calculation in GREET. The mix of energy inputs for coal production and for other key components in the life cycle are also identified in Appendix B. The analysis was conducted in a GREET1_2017 model with electric power generation and crude oil production resources configured for a China mix. Table 5.1 shows the upstream emissions for coal produced in China. A range of GHG emissions are available in the literature from values that are comparable to the U.S. coal inputs in GREET to much higher amounts of coal associated with coal mining. These higher levels of coal appear to correspond to coal mine fires (ASIACHEM, 2018; Jiang, Ou, Ma, Li, & Ni, 2013). The upstream life cycle emission rates for China coal are shown in Table 5.1.

Table 5.1. Upstream Life Cycle Emission Rates from Baseline China Coal

	Emissions (g/mmBtu), HHV [a]			
Processing Step	**CO_2**	**CH_4**	**N_2O**	**CO_2e**
China Coal				
Coal Mining and Processing	3,472	8.00	0.04	3,683
Extraction Fugitive	0	229	0	5,723
Transport	920	1.85	0.02	973
Total China Coal [b]	4,392	239	0.06	10,380
Total China Coal (kg/tonne coal)[c]	97.0	5.3	0.0	229.3

Source: GREET1_2017, China electricity and crude oil mix

[a] The functional unit in the GREET model is mmBtu of coal for an average coal with HHV of 20.6 mmBtu/tonne, the average HHV of gasification and steam coal is 21.9 mmBtu/tonne (Appendix C)

[b] Energy consumption is based on data from Jiang, 2013 which is in the same range as ASIACHEM, 2018. Compare to 217.8 kg CO_2e/tonne from ASIACHEM, 2018

[c] Emission rate based on average coal heating value

Table 5.2. Upstream Life Cycle Emission Rates from Low Emission Coal

Processing Step	Emissions (g/mmBtu), HHV CO_2	CH_4	N_2O	CO_2e
China Coal				
Coal Mining and Processing	807	1.39	0.01	845
Extraction Fugitive	0	146	0	3,639
Transport	919	1.83	0.02	972
Total China Coal	1,726	149	0.03	5,456
Total China Coal (kg/tonne coal)	38.1	3.3	0.001	120.5

Source: GREET1_2017, China electricity and crude oil mix, Appendix B.
[a] The functional unit in the GREET model is mmBtu of coal for an average coal with HHV of 20.6 mmBtu/tonne, the average HHV of gasification and steam coal is 21.9 mmBtu/tonne (Appendix C)
[b] Compare to 140.8 kg CO_2e/tonne from ASIACHEM, 2018 for clean coal production.

Table 5.3 shows the upstream life cycle emissions for China coal to methanol for each scenario. The coal consumption rate and the source of upstream data vary with each scenario. The coal consumption rate varies by process scenario. Note that the Upper emission scenario is based on the low range of coal consumption since China methanol is the displaced product.

The Market Mediated case examines the market effect of coal that is available from displaced methanol. The effect of additional coal in China and the supply curve for coal is discussed in Appendix F. The net effect of removing coal feedstock from coal-based methanol is an increase of 57 kg CO_2e/tonne of methanol assuming that coal demand responds to the change in supply.

Table 5.3. Upstream Life Cycle Emissions for China Coal to Methanol

Baseline	Baseline	Lower	Upper	Market Mediated
Coal (tonne/tonne methanol),[a]	2.20	2.31	2.09	2.20
Coal Upstream Source	Jiang	Jiang	GREET	Jiang
GHG Emissions (kg/tonne methanol)[b]				
CO_2	213.0	223.7	79.7	156.0
CH_4	11.6	12.2	6.9	11.6
N_2O	0.003	0.003	0.002	0.003
CO_2e	503.4	528.6	252.0	446.4

[a] Coal consumption rate based on data in Section 2.4.1. Lower and Higher cases assume a +/-5% change in coal consumption rate.
[b] GHG emissions correspond to coal use rate combined with upstream life cycle emission rates in Tables 5.1 and 5.2

5.1.2 Electric Power Production

Coal to methanol plants require electric power to operate the oxygen plant, compressors, and other equipment. Some of the power is generated on site from waste heat with the balance imported from the local grid. Table 5.4 shows the upstream life cycle emissions for electric power based on the China electricity mix. The Lower scenario includes a coal intensive mix for Inner Mongolia with 90% coal-fired power plants (ASIACHEM, 2018).

Table 5.4. Upstream Life Cycle Emission Rates for China Power

		Emissions (g/kWh)			
Resource Mix	**Life Cycle Step**	**CO_2**	**CH_4**	**N_2O**	**CO_2e**
China Low Emission (GREET)	Upstream	13	0.89	0.000	35.5
	Power Plants	573	0.01	0.010	576
China Baseline (Jiang et al., 2013)[a]	Upstream	28	1.38	0.001	62.5
	Power Plants	573	0.01	0.010	576
China (Inner Mongolia Coal) [b]	Upstream	39	1.98	0.001	88.8
	Power Plants	826	0.01	0.014	831

Source: GREET1_2017 inputs described in Appendix B. Power generation mix from China Automotive Energy Research Center, 2013. Upstream emission rate for power varies with coal upstream data in Section 5.1.1.

[a] Emission from coal production affect power generation upstream.

[b] 90% coal power mix, 7000 kcal/kg coal, 309 g coal/kWh (ASIACHEM, 2018)

The imported power required for imported coal to methanol depends on how the facility is configured. Coal to methanol plants raise steam in a boiler and power is extracted from high pressure steam. One option is to import additional power from the grid. Most of the literature on coal to methanol facilities described in Appendix D involves design studies for plants with cogeneration (Jacobs, 2013; Supp, 1990). The power consumption from ASIACHEM (2018) provides the basis for the analysis here.

Table 5.5. Upstream Life Cycle Emissions for Electric Power used in Coal to Methanol

Baseline	Baseline	Lower	Higher	Market Mediated
Power Use (kWh/tonne)	288	288	288	288
Power Source	China Average	Inner Mongolia Coal	GREET	China Average
(kg/tonne methanol)[a]				
CO_2	173.0	236.4	173.0	173.0
CH_4	0.4	0.3	0.4	0.4
N_2O	0.003	0.06	0.003	0.003
CO_2e	183.9	260.8	183.9	183.9

Source: GREET analysis in Appendix B for China electricity mix

[a] GHG emissions correspond to import power From Table 2.4 combined with upstream life cycle emission rates in Table 5.4

5.2 Coal to Methanol Emissions

Direct emissions from the coal to methanol correspond primarily to the combustion of coal for on-site power and the unconverted CO_2 from the methanol production process. The coal to methanol yield affects the upstream coal gas emissions previously discussed.

Emissions from coal to methanol are calculated during continuous operation to provide a conservative estimate of the emissions from displaced methanol. Energy inputs and emissions from continuous operation are based on various studies on coal to methanol discussed in Appendix D. A carbon balance provides the basis for the net emissions followed by a summary of coal to methanol emissions.

5.2.1 Carbon Balance

GHG emissions from coal-based methanol production process consist of coal fired boiler emissions and vent gas from the Rectisol process. The carbon balance is shown in Figure 3.2 with the inputs for a typical coal to methanol plant. The carbon balance shows the mass, energy content and carbon in the facility. The distribution of the coal inputs is also shown. The net CO_2 emissions are consistent with the carbon balance in the following equation:

$$C_{CM} = C_{CoalG} + C_{coalS} - C_{MeOH} + C_{Ash} \quad (6)$$

Where

C_{CM} = Carbon emission

C_{CoalG} = Carbon in gasification coal

C_{coalS} = Carbon in steam coal

C_{MeOH} = Carbon in methanol

C_{Ash} = Carbon in Ash

Thus, the carbon in the fuel gas is determined by difference, which is also the method used in the GREET model.

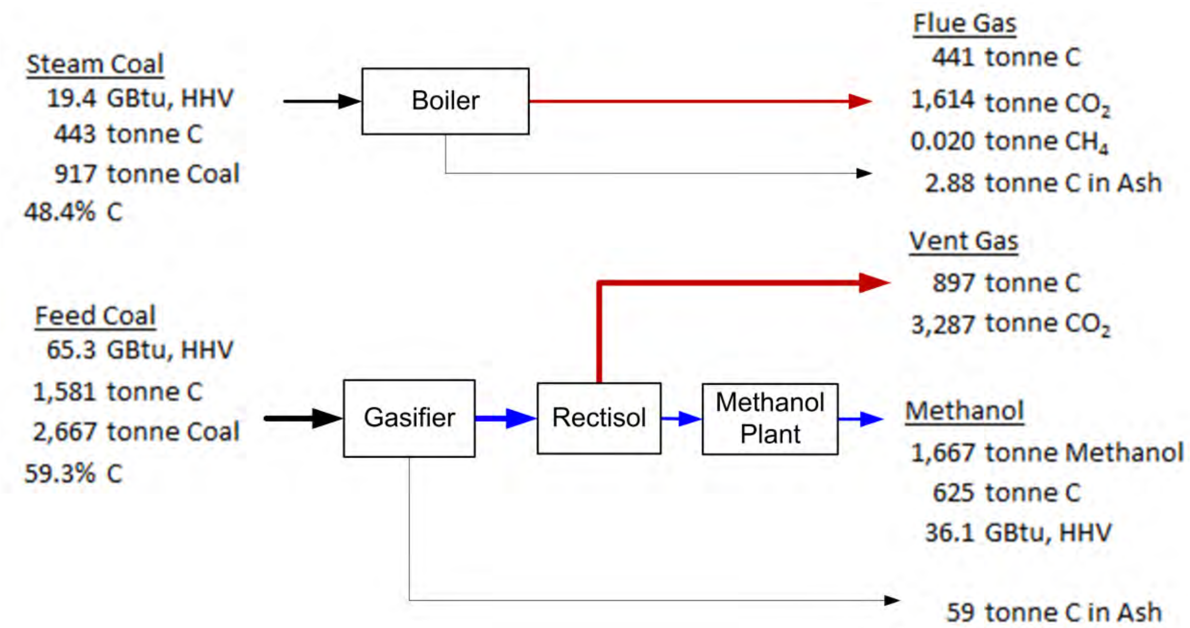

Figure 5.2. Mass and Energy Balance for 600 ktpa Coal to Methanol.
Source: Carbon balance for 600 ktpa plant from Table 2.4

The carbon content of gasification coal (similar to subbituminous coal) and steam coal (lignite) vary significantly, however, the CO_2 embedded in the coal per mmBtu is relatively constant as discussed in Appendix C.

The carbon balance in Figure 5.2 provides the basis for determining CO_2 emissions and the energy inputs to the boiler provide the basis for determining CH_4 and N_2O emissions. Table 5.6 shows the direct emissions based on the weighted average inputs for coal production from the technology mixes in Section 4. CO_2 emissions are based on the properties of gasification coal and steam coal (Appendix C). The use of diesel equipment was assumed to be one third of that for the KMMEF for the smaller size coal-based facility. CH_4 and N_2O emissions are proportional to the energy throughput

Steam coal is fired directly in a boiler to raise steam and generate power. The combustion emissions correspond to steam coal properties in Appendix C. Emissions from the Rectisol unit correspond to the difference in the carbon entering the gasifier and the methanol product minus ash.

Table 5.6 shows the annual emissions from the 600 k tonnes/year system described in Figure 5.2. CH_4 and N_2O emissions for steam coal combustion are based on emission factors in Appendix C. The capacity of 600,000 MTPA is selected for the Study as this is the typical size of a standalone coal to methanol plant which sells methanol on the merchant market (ASIACHEM 2018).

Table 5.6. Direct Emissions from 600 ktpa Coal to Methanol Facility.

Emission Unit	CO_2	CH_4	N_2O	CO_2e
GHG Emissions (tonne/yr)				
Steam Coal[a]	581,039	6.1	9.2	583,938
Rectisol[b]	1,183,480	0	0	1,183,480
Diesel Equipment[c]	100	0.01	0.00	101
Fugitive methanol as CO_2[d]	0.4			0.4
Total Direct Emissions	1,764,620	6	9	1,767,519
kg/tonne methanol	2941	0.0	0.02	2946

[a] Based on steam coal use rate in Table 2.4 and emission factors in Appendix C.
[b] Based on carbon balance in Figure 5.2
[c] Assume 1/3 of KMMEF fuel use for smaller facility
[d] From Appendix A.3

Table 5.7 shows the marginal mix of methanol plants from the supply curve in Section 4.5.1. The coal use rates are grouped by facility size with smaller facilities estimated to be less efficient than larger facilities as discussed in Appendix D. The emissions from the aggregate marginal coal to methanol facility are shown in Table 5.8.

Table 5.7. Coal Input Rates for Marginal Methanol Plants

Type	Number of Plants	Capacity (k tonne/y)		Coal/tonne methanol	
		Average	Total	mmBtu, HHV	tonne
Coal > 300 kt	1	300	300	46.4	2.10
Coal < 300 kt	2	220	440	50.8	2.32
Coal Am > 300 kt	6	385	2310	46.4	2.10
Coal Am < 300 kt	4	131	525	50.8	2.32
Aggregate	13	275	3575	47.6	2.16

Table 5.8. Direct Emissions from Marginal Coal to Methanol Facility.

Emission Unit	CO_2	CH_4	N_2O	CO_2e
GHG Emissions (tonne/yr)				
Steam Coal[a]	606,705	6.4	9.6	609,732
Rectisol[b]	1,210,577	0	0	1,210,577
Diesel Equipment[c]	100	0.01	0.00	101
Fugitive methanol as CO_2[d]	0.4			0.4
Total Direct Emissions	1,817,382	6	10	1,820,410
kg/tonne methanol	3029	0.0	0.02	3034

[a] Based on steam coal use rate in Table 5.7 and emission factors in Appendix C.
[b] Based on carbon balance in Figure 5.2
[c] Assume 1/3 of KMMEF fuel use for smaller facility
[d] From Appendix A.3

The direct GHG emission results for each scenario are shown in Table 5.9. The emission levels are calculated with the mass balance model for the different coal to methanol conversion rates in the table. A variability of +/- 5% in the coal to methanol yield is assumed based on the variability in data in Appendix D.

Table 5.9. Direct Emissions for Coal to Methanol.

Scenario	Baseline	Lower[a]	Upper	Market Mediated
Coal t/t	2.20	2.31	2.09	2.20
kg CO_2e/t	3034	3186	2890	3034

[a] Emission rate for lower scenario since greater coal emissions result in lower net emissions from the KMMEF

5.3 Alternative Methanol Distribution

Downstream emissions from alternative methanol production include shipping to an MTO facility in Bohai Tianjin, China. Based on the mix of methanol plants that were marginal producers in Section 4.5.2, methanol would be transported by truck from China based facilities. Emissions from methanol transport is examined in this section.

5.3.1 Methanol Transport Emissions

Most methanol in China is transported by tanker truck such as the one shown in Figure 2.13. While it may be more efficient to transport methanol by rail, China does not have an extensive rail network and most methanol is transported by truck. Some methanol is also transported by truck and barge combination (ASIACHEM, 2018).

Table 5.10. Energy Intensity for Truck Transport to Bohai Tianjin, China

Truck Hauling	km	Btu/ tonne-km
Ordos to Tianjin, Bohai	850	519.3
Empty Backhaul	850	467.4

Source: (China Chemical Fiber Group, 2017)
Energy intensity calculated from fuel consumption of 45 L/100 km (ICCN & Dieselnet, 2018) and truck capacity in Figure 2.13.

Table 5.11 shows the GHG emissions associated with methanol transport in China. The emissions are based on trucking the methanol the average distance of 850 km which is based on methanol plants on the margin. Energy inputs from Table 5.10 are combined with direct and upstream emission factors for China diesel fuel to determine the emissions per tonne of methanol.

Table 5.11. Emissions from Alternative Methanol Transportation

Pollutant	CO_2	CH_4	N_2O	CO_2e
Emissions (g/mmBtu), HHV				
Direct Emission Factor	78,186	4.7	0.2	78,357
Upstream Life Cycle Rate	12,170	163	0.2	16,317
Emissions (kg CO_2e/tonne methanol)[a]				
Direct	65.6	0.01	0.0003	65.8
Upstream	10.2	0.24	0.0003	16.4

Source: Emission factors from Appendix B

[a] GHG emissions correspond to fuel use rate in Table 5.10 with emission factors in this table.

5.3.2 Upstream Life Cycle Emissions from China Petroleum Fuels

The upstream emissions associated with diesel fuel production were calculated based on the mix of crude oil resources for China oil refineries as well as the electricity mix and coal production energy inputs described in Section 5.1. The upstream life cycle emissions for diesel and gasoline use in China were calculated using the GREET1_2017 model with inputs described in Appendix B.

5.4 Comparison of Naphtha and Methanol to Olefins

The use of methanol from the KMMEF as a feedstock for olefin production compared to coal based methanol supply does not affect the direct emissions from the MTO plant itself, but, as discussed in the prior section, has a strong influence on the amount of upstream emissions in addition to the coal to methanol comparison. The relative comparison of emissions from MTO and other olefin routes is of interest. Naphtha's historically predominant role as an olefin feedstock makes a direct comparison with naphtha to olefin of particular interest.

The methanol-to-olefins (MTO) reaction is highly exothermic. The process typically does not need any external fuel. Two studies which focus on the analysis of MTO process (Dimian & Bildea, 2018; Tian, Wei, Ye, & Liu, 2015) provide estimates of the energy inputs and yields and data to support a mass balance in Appendix E. The studies reveal similar values for the different olefin routes as well as the yield of olefins from methanol.

Light olefins (C2 to C4) represent about 90% of the hydrocarbon products by mass. A feed of 100 kg of methanol produces about 38 kg of ethylene + propylene + butylene. Additionally, is the process generates about 1.7 kg of heavier olefins and 4.7 kg of coke + CO + CO_2. The coke + CO_2 + CO fraction is consumed in the process to derive heat. A significant amount of water is co-produced in the process which does not affect our GHG emission calculations.

As the MTO process does not consume any imported fuel, the process emissions from MTO are lower than those from the naphtha to olefin route. The naphtha route produces about 53 kg of olefin from 80 kg of naphtha feed. On the whole, this analysis shows that the GHG emissions from MTO are approximately 10% lower than steam cracking of naphtha to olefins though the results are dependent upon the source of crude oil, refinery efficiency and yields. Note that naphtha is a byproduct of petroleum refining and its price is tied to the price of petroleum. An increase in olefin production from naphtha requires an increase in overall global petroleum refining. A source of additional naphtha would be by tanker ship delivery, from sources such as the West coast of the U.S.

In sum, as shown in Figure 5.3, KMMEF methanol presents a life cycle GHG emission level below that of naphtha, with coal-based methanol production emissions at a significantly higher level. As relative growth in MTO production continues as compared to naphtha, displacement of coal to methanol by gas to methanol results in reduced overall GHG emissions.

Table 5.12. Net Inputs and Emissions for Olefin Production

	Steam Cracking	MTO	
Inputs/ Emissions per kg olefin	**Petroleum Naphtha**	**KMMEF Methanol**	**Coal Methanol**
Feed Yield (kg/kg olefin)	1.7[a]	2.6 to 3	2.6 to 3
Life cycle emissions (kg CO_2e/kg olefin)[a]			
Feed upstream	1.18 to 1.42[b]	1.55 to 1.8	10 to 11.4
Process Emissions	1.08	0.3 to 0.45	0.3 to 0.45
Imported Refinery Fuel Gas	0.06	0	0
Total	**2.32**	**1.85 to 2.26**	**10.3 to 11.9**

Source: Appendix D

[a] Net yield after return of unconverted naphtha is taken into account. Detailed analysis in (Forman et al., 2014)

[b] Upstream life cycle emissions based on GREET (15.3 g CO_2/MJ)., which assigns a higher refinery efficiency to naphtha than to fuel products for China refineries. High range corresponds to naphtha from California refineries shipped to China.

The total life cycle naphtha CI is about 15.3 g CO_2e/MJ. Crude oil extraction contributes 8.4 g while the naphtha refining contributes 7.3 g CO_2e/MJ. More details are specified in the Appendix E

Considering the end use of methanol for MTO results in the same net emission reductions for KMMEF methanol that displaced coal methanol. 3.6 million tonnes per year of methanol would result in a total of 2.59 million tonnes of GHG emissions if the MTO facility is counted which would displace 14.1 million tonnes of emissions from coal based MTO. Even if KMMEF methanol displaced naphtha from steam cracking, this route to olefin production would result in 2.65 to 3.2 million tonnes of GHG emissions per year[24]. Even though the emissions from naphtha steam cracking are far below those of coal based MTO, producing additional naphtha requires the refining of crude oil and naphtha supplies will not increase unless more crude oil is refined.

[24] Annual emissions from methanol and MTO = 2.17 million tonne/year + 0.3/2.6 × 3.6 million tonnes methanol = 2.59 million tonnes CO_2e. Emissions from naphtha based olefins = 2.32/1.85 x 2.58 = 3.23 million tonnes.

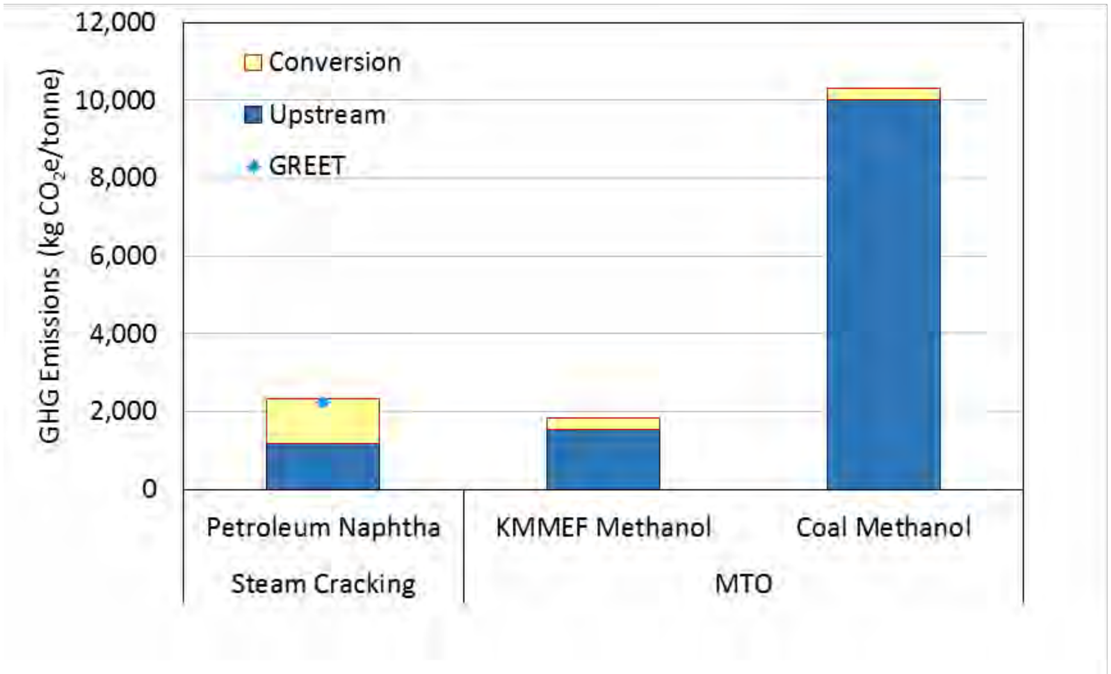

Figure 5.3. Life Cycle GHG Emissions from Olefin Production Routes.
Source: Appendix E

5.5 Effect of Methanol as Fuel

Methanol displaces other fuels in various applications in China. These include some of the following:

- DME for home cooking displacing coal
- Blending component for gasoline displacing petroleum gasoline
- Feedstock for MTBE and MTG displacing petroleum gasoline
- Methanol for industrial fuel displacing coal

This Study does not quantify the GHG emissions from all of the potential methanol fuel options. Nonetheless, the comparison of methanol to other fuels is of interest and a directed topic of analysis as more fully discussed in Section 4.3.5., above.

When methanol is used as a fuel, the direct emissions are the same regardless of the source of methanol; so, only the upstream emissions related to the production and delivery of the methanol impacts the life cycle emissions. Thus, KMMEF methanol would result in lower emissions than the use of coal as a fuel. The use of methanol as a gasoline replacement is also of interest due to the large volume of gasoline used globally. The use of methanol affects the octane properties of fuel and fuel consumption. Figure 5.4 shows the GHG emissions from substituting KMMEF methanol for gasoline as roughly equivalent with the more likely displacement of coal-based methanol presenting significant GHG emission improvement.

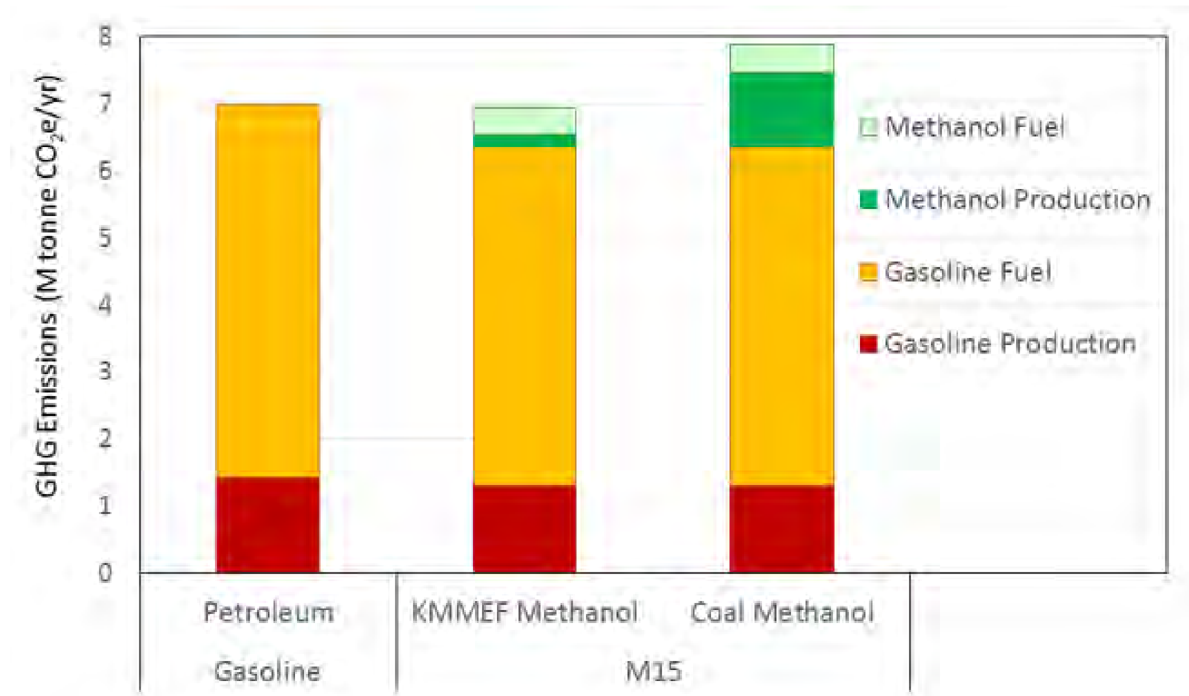

Figure 5.4. Life Cycle GHG Emissions from gasoline and methanol M15 Fuels.
Source: Appendix D

A new source of methanol will not affect the end use demand other than through secondary market effects. China methanol plants operate at relatively low capacity factor with expensive methanol. Since the existing excess capacity is not fully deployed to serve the fuel market, a new source of methanol should not shift expensive coal methanol into the fuel market. Again, substitution and displacement by KMMEF methanol does not result in an increase in GHG emissions.

6. LIFE CYCLE ASSESSMENT

Net GHG emissions were evaluated for the range of scenarios considered in this Study. Emissions are grouped according to construction, operational, and displaced emissions. The operational and displaced emissions are further broken out by upstream, direct and downstream emissions. Table 6.1 shows the annual GHG emissions from KMMEF methanol. The scope of emissions includes KMMEF construction, upstream operation, and downstream activities as indicated below. The displaced emissions are also shown in the table. Construction emissions are spread over a 40-year project life which is consistent with the lifetime of industrial facilities including methanol plants that are in operation today.

Scenarios for emissions represent the effect of variation in the following:

- electricity mix for the KMMEF
- upstream natural gas emissions
- methanol production feedstock inputs
- electricity mix for China
- coal production emissions
- tanker ship capacity
- market effects

The life cycle GHG emissions from KMMEF methanol correspond to a net reduction of 9.7 to 11.5 tonnes per year when compared to a coal to methanol alternative displaced supply. The operational plus construction emissions from the KMMEF including upstream and downstream emissions range from 1.96 to 2.62 million tonnes of GHG emissions per year compared with 12.3 to 14.6 million tonnes of GHG emissions from displaced methanol. The displaced emissions are the result of a market analysis that examined the supply and demand for methanol as well as the projected demand for methanol.

Table 6.1 also shows the portion of the annual KMMEF GHG emissions that occur within in the State of Washington. These emissions include all of the KMMEF direct emissions, pipeline compressor operation and leaks in Washington[25], fossil fuel power generation, Washington portion of natural gas and coal transport for power generation[26], 3 miles of tanker ship operation plus pilot vessel operations and Washington oil refinery operation to make fuel for methanol transport[27].

[25] Data on Washington pipeline emissions from EPA's FLIGHT Tool (http://ghgdata.epa.gov/ghgp).

[26] Washington fraction of rail transport from Powder River Basin.

[27] Excludes crude oil production and refining of petroleum products in China for return trip to KMMEF.

Table 6.1. Average Annual Net Life Cycle GHG Emissions

Scenario	Baseline	Lower	Higher	Market Mediated	Baseline in WA
	Average Annual GHG Emissions (million tonne/annum)				
Construction Emissions					
Direct	0.0004	0.0004	0.004	0.004	0.0002
Upstream	0.015	0.015	0.015	0.015	0.001
Operational Emissions					
Upstream Natural Gas	1.04	1.03	1.23	1.04	0.052
Upstream Power	0.19	0.00	0.28	0.22	0.017
Direct Emissions	0.73	0.73	0.73	0.73	0.73
Downstream Emissions	0.17	0.17	0.30	0.17	0.00009
Petroleum Fuel Production	0.03	0.03	0.06	0.03	0.0048
KMMEF Total	**2.17**	**1.96**	**2.62**	**2.20**	**0.96**
Displaced Emissions					
Upstream Feedstock	1.81	1.90	0.91	1.61	
Upstream Power	0.66	0.94	0.66	0.66	
Direct Emissions	10.92	11.47	10.40	10.92	
Downstream Emissions	0.24	0.24	0.24	0.24	
Petroleum Fuel Production	0.06	0.06	0.06	0.06	
Displaced Total	**13.69**	**14.61**	**12.27**	**13.49**	
Net Emissions[b]	**-11.5**	**-12.6**	**-9.6**	**-11.3**	

[a] Construction emissions occur over a 36 month period and are represented over a 40-year facility life.
[b] Totals may not sum due to rounding.

Table 6.2 shows the GHG emissions on a per-tonne of methanol basis. The emissions from Table 6.1 are divided by the annual production capacity of 3.6 million tonnes per year. These results provide the basis for comparing this Study with other assessments of GHG emissions.

Table 6.2. GHG Emissions from KMMEF per tonne of Methanol

	GHG Emissions (kg CO_2e/tonne methanol)			
Scenario	**Baseline**	**Lower**	**Upper**	**Market Mediated**
<u>Construction Emissions</u>				
Direct	0.1	0.1	0.1	0.1
Upstream	4.0	4.0	4.0	4.0
<u>Operational Emissions</u>				
Upstream Natural Gas	289	285	340	289
Upstream Power	51.5	0	77.9	61.7
Direct Emissions	202.2	201.7	202.2	202.2
Downstream Emissions	46.0	46.0	84.7	46.0
Petroleum Fuel Production	8.7	8.7	17.2	8.7
KMMEF Total	**602**	**545**	**727**	**612**
<u>Displaced Emissions</u>				
Upstream Feedstock	503	529	252	446
Upstream Power	184	261	184	184
Direct Emissions	3034	3186	2890	3034
Downstream Emissions	65.8	65.8	65.8	65.8
Petroleum Fuel Production	16.4	16.4	16.4	16.4
Displaced Total	**3804**	**4057**	**3408**	**3747**
Net Emissions	**-3202**	**-3512**	**-2681**	**-3135**

Figure 6.1 shows the contributions of GHG emissions for the Baseline scenario comparing each of the categories. Factors that affect the feedstock emissions include methane leaks from pipelines, coal mine methane, as well as coal that is burned in coal mine fires. Emissions for power vary with the electric generation mix. The largest difference between the KMMEF and displaced methanol occurs at the methanol production plant. CO_2 released from a coal methanol plant is over 5 times as high as that of the KMMEF with its ULE technology. Finally, transportation emissions are comparable due to the efficiency of marine tanker transport.

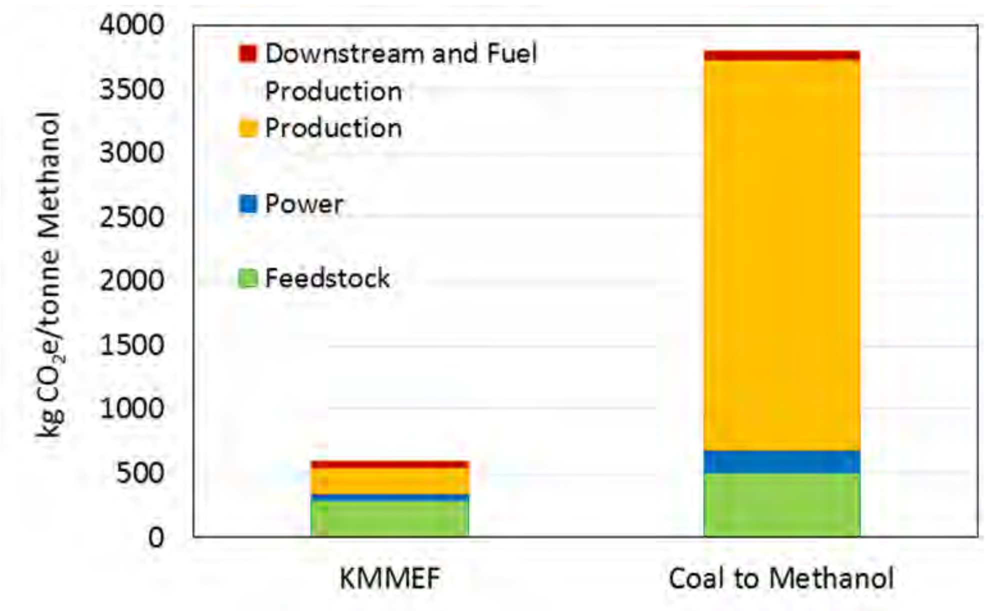

Figure 6.1. Life Cycle GHG comparison.

6.1 Sensitivity Analysis

Figure 6.2 shows the sensitivity of key inputs to the life cycle GHG emissions which are summarized in Appendix A.4. The Baseline case represents the inputs that appeared to be the most likely to correspond to the KMMEF operation and displaced methanol. The Upper and Lower scenarios encompass the range of emission assumptions. The contribution of key factors is illustrated in the figure. The most significant factors are associated with coal production including power generation mix and coal use rate. Other factors that result in the variability of the emission estimate include the upstream emission components for the KMMEF. Any variability associated with the displacement of methanol is represented by the range in market effects. Methanol produced from the KMMEF will displace other sources of methanol and second order market effects such as the availability of coal are on the order of the smaller variations in this Study. Variability in the upstream CH_4 for natural gas production has a modest effect on overall GHG emissions. For example, even applying a hypothetical natural gas extraction emissions rate that is 4 times higher than the GREET model extraction emissions or 3.05% times total CH_4 emissions results in a variability that is no higher than others shown in the figure. The GWP of methane, based on the ARB values results in lower net emissions from the KMMEF since overall CH_4 emissions are higher from alternative methanol production, primarily due to coal mine methane.

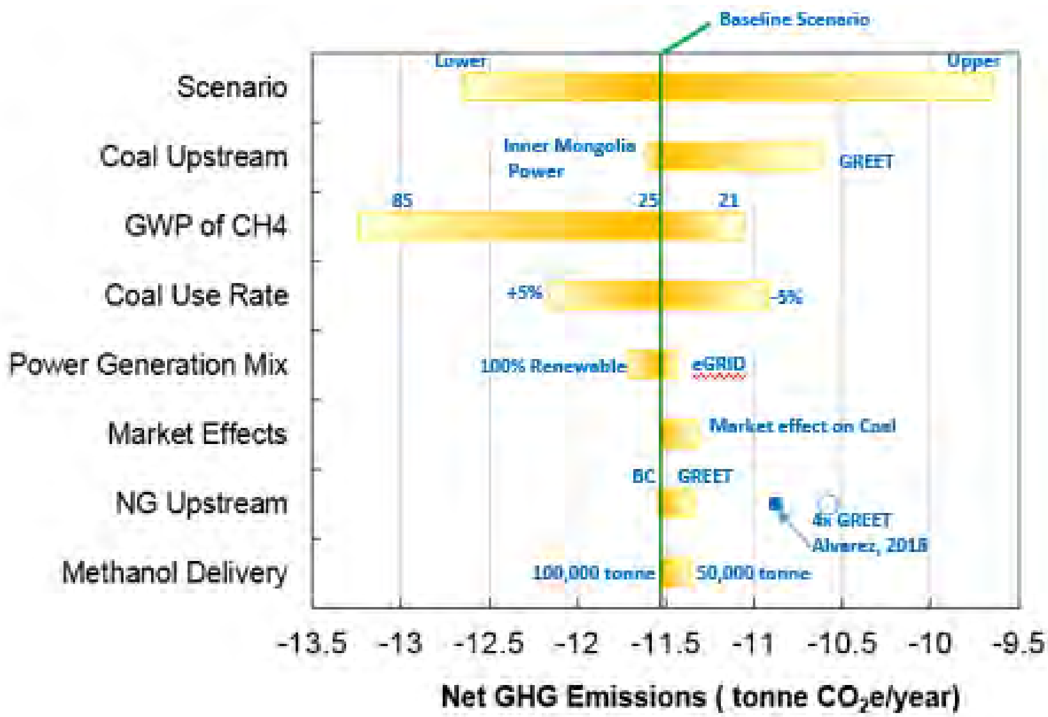

Figure 6.2. Sensitivity analysis to key inputs.

Emission Results using 20 Year AR4

All results shown in this LCA are based on the AR4 100-year GWP as previously discussed in Section 2. The figure also provides sensitivities for natural gas upstream assumptions. For example, a higher GWP of methane results in lower net GHG emissions from the KMMEF since net emissions from coal mine methane combined with the use rate of coal to methanol are higher than those from the KMMEF. If a 20-year GWP were to be considered, the net result would show even greater GHG global reductions against coal to methanol production as indicated in Table 6.3.

Table 6.3. 20-year GWP Comparison of Life Cycle GHG Emissions

Scenario	**Baseline**	**Lower**	**Upper**	**Market Mediated**
KMMEF Total	3.08	2.85	3.92	3.14
Coal to Methanol	16.33	17.34	13.89	16.13
Net Emission Reductions – 20 year GWP	13.2	14.5	10.0	13.0
Net Emission Reductions – 100 year GWP	11.5	12.6	9.7	11.3

7. CONCLUSIONS

Life cycle GHG emission from the KMMEF were analyzed over a range of scenarios covering upstream emissions, facility operation, displaced alternative sources of methanol, and end uses of methanol conforming to international standards and utilizing the GREET framework to calculate emission rates. Over the range of scenarios analyzed, the production and market entry of KMMEF methanol results in net GHG reductions ranging from 9.7 to 12.6 million tonnes CO_2e/year.

These reductions in GHG emissions are largely due to the displacement of coal-based methanol in China. Life cycle GHG emissions for coal to methanol range from 3400 to 4060 kg CO_2e/tonne of methanol compared with 550 to 730 kg CO_2e/tonne methanol from the KMMEF. Several key factors affect the calculation of KMMEF emissions, including emissions associated with construction, on-site facility operations, upstream purchased power, shipping and, significantly, natural gas supply. Likewise, parallel calculation factors for coal to methanol provide the estimate of displaced emissions including emissions associated with coal as feedstock and power generation. In addition to the KMMEF technology upstream factors, this feedstock distinction represents the significant distinguishing factor between the emission profiles.

Production of methanol from the KMMEF will displace methanol from other sources. An analysis of the long-term supply curve for methanol indicates that Chinese coal based methanol will remain the marginal (highest cost for delivered product) producer for many decades. Methanol from the KMMEF is one of the lower cost products with access to the China market. Therefore, additional methanol provided to China stands to displace methanol from these marginal, coal-based resources. While short-run variations will occur in the methanol markets, in the long run low cost producers will displace higher cost coal to methanol facilities.

Methanol from the KMMEF will be used as a feedstock for MTO facilities in East China. The use of MTO as a source of olefins is consistent with the resource mix that is available in China. Other sources of olefins such as catalytic cracker co-product from oil refineries and ethane from natural gas are in limited supply in the region. Naphtha has historically been the predominant feedstock for Chinese olefin production and the relative market share continues to decline due to rapid MTO growth. It is notable that while KMMEF methanol has a lower life cycle GHG emissions in comparison to coal to methanol its emissions are also slightly lower than those from naphtha on a life cycle basis. Thus, the KMMEF represents the lowest GHG methanol to olefin production at a scale sufficient to impact markets and displace higher emitting alternatives.

While methanol from the KMMEF will be dedicated to MTO facilities~~,~~ a quantitative view of methanol as fuel emissions against relevant comparative fuel emissions was of interest. Methanol's fuel carbon content, upstream emissions and the effect of its high-octane level on vehicle efficiency and oil refining result in overall GHG emissions that are comparable to crude oil derived gasoline in China. When compared to emissions from alternative coal-based methanol or coal as fuel, natural gas-based methanol results in even greater emission reductions.

The Chinese methanol market has demonstrated strong growth over the last decade and is anticipated to continue to grow for the foreseeable future. Both market forces and governmental policy in China have combined to drive this growth. In the absence of reliable imported sources of methanol Chinese companies are planning to build up to 16 new coal to methanol facilities with total capacity of 12 MTPA from 2018 to 2023 to meet this demand (ASIACHEM, 2018). This coal to methanol growth and corresponding GHG impacts is the most likely market driven outcome of inaction or failure to build new natural gas-based methanol facilities. While future innovation may eventually present alternatives toward this end, this Study limited its quantitative review of commercially proven technologies at scale for displacing these rapidly expanding, higher GHG emitting coal to methanol facilities.

This Study takes into account the factors identified in the scoping document and shows the analysis of a full life cycle basis including natural gas and power production, KMMEF emissions, transport and the effect of displaced methanol as a feedstock for MTO or for other applications. Total net GHG emissions associated with KMMEF operation range from a reduction of 9.7 to 11.5 million tonne CO_2e/year. Whether it is through displacement of existing coal to methanol facilities or by causing companies to cancel planned coal to methanol facilities, the introduction of KMMEF methanol into the MTO market will allow the GHG reductions discussed in this Study to be realized.

Appendices

This report serves as the appendix to the Kalama Manufacturing and Marine Export Facility (KMMEF) Supplemental GHG Analysis report. Appendix A describes the life cycle emission quantification approach for construction and operational GHG emissions associated with the KMMEF and its alternatives. Appendix B provides details on life cycle upstream emission quantification for natural gas, electricity , coal and petroleum fuels. Appendix C provides emission factors for each type of combustion equipment and fuel combination used to calculate direct emissions. Appendix D provides data on the energy inputs for methanol production and its use in fuel applications. Appendix E describes olefin production while Appendix F provides details on the market study of Chinese natural gas and coal prices.

A. Appendix A Calculation Approach

The Study calculates GHG emissions from KMMEF methanol production and displaced methanol on a life cycle basis. [28].

Emissions for the KMMEF and the alternative methanol production methods are divided into emissions from the construction of the plant and the operation of the plant. Each of these emission categories is further divided into direct emissions, upstream life cycle emissions and downstream life cycle emissions. Direct emissions are those emissions that result from direct combustion of a process fuel or venting/fugitive emissions. Downstream emissions are those emissions that result from the combustion of fuel used for methanol transport. For operations that utilizes natural gas or coal in an on-site boiler, the direct emissions correspond to the combustion of the natural gas or coal in the boiler. The emissions from the extraction, processing and transport of the natural gas or coal would be considered as upstream emissions.

The above calculations are embedded into life cycle models including GREET and GHGenius. These models combine aggregate statistics for oil and natural gas production as well as power generation with the parameters for fuel production to develop a life cycle analysis for multiple fuel and other material pathways. This Study follows the calculation framework in GREET. The calculations for methanol production and transport are repeated in an external spreadsheet and upstream life cycle emission rates are extracted from the GREET and GHGenius models.

The following sections summarize the generalized approach to quantify construction emissions, emissions associated with operation of the plant and emissions from displaced methanol operations. A description of fugitive emission estimation methods is also provided.

A.1. Construction Emissions

Construction results in emissions from fuel use, imported power and the production of construction materials. The fuel use also includes emissions from transportation of workers and goods to the construction site. Life cycle construction emissions were calculated based on the following:

$$\mathbf{G}_{KC} = \Sigma(U_{FC} \times (\mathbf{EF}_F + \mathbf{E}_F)) + C_D + U_{eC} \times \mathbf{E}_e + \Sigma(U_m \times \mathbf{E}_m) \qquad (7)$$

Where:

$\mathbf{G}_{KC}$ = KMMEF Construction GHG emissions in total tonnes

Σ refers to summation over equipment types or construction materials

[28] The use of fuel to produce the fuel is handled within the GREET and GHGenius models. For example, refining crude oil for diesel fuel to operate equipment used to extract crude oil is handled within these models by iterative calculations.

U_{FC} = Fuel use for each application during construction including construction equipment, transport of materials by marine vessel or truck, dredging, and employee commuting
$\mathbf{EF_F}$ = Direct emission factor for diesel and LPG, and gasoline (g/mmBtu)
$\mathbf{E_F}$ = Upstream life cycle emission rate from fuels (g/mmBtu)
C_D = Carbon released from dredging as CO_2
U_{eC} = Electric power used during construction
$\mathbf{E_e}$ = Upstream emissions from imported electric power (g/kWh)
U_m = Materials used in construction for each type of material
$\mathbf{E_m}$ = Upstream emission rate for each material of construction (kg/tonne)

Emissions from fuel use are summed over each type of construction equipment and fuel. Similarly, emissions from construction materials are summed over all of the materials used for the KMMEF.

Catalyst inputs, maintenance, and decommissioning were identified as being below the cut off criteria for this Study. All of these activities would also occur for displaced methanol and total emission would be less than 1% for the life of the project as discussed in Appendix A.4.

A.2. Operational Emissions

Operational emissions consist of direct emissions from on-site combustion and fugitive emissions, upstream emissions from power imports and natural gas extraction, processing and transmission and downstream emissions from methanol transport to China. Each of these emission events has an upstream life cycle component. Operational emissions $\mathbf{E_{KO}}$ are expressed by the following equation:

$$\mathbf{E}_{KO} = S_{NG} \times \mathbf{E}_{NG} + S_e \times \mathbf{E}_e + S_{PGU} \times \mathbf{EF}_{NG} + \mathbf{E}_K + V_f + \Sigma(D \times (S_T + S_{Tb}) \times (\mathbf{EF}_R + \mathbf{E}_R)) + T_f \qquad (8)$$

Where:

$\mathbf{E_{KO}}$ = Total operational emission rate (kg/tonne)
S_{NG} = Specific energy of total natural gas input (Btu/tonne methanol)
$\mathbf{E_{NG}}$ = Upstream life cycle emission rate for natural gas (g/mmBtu)
S_e = Specific Energy of electric power
$\mathbf{E_e}$ = Upstream life cycle emission rate for electric power (g/kWh)
S_{PGU} = Specific energy of natural gas to power generation unit
$\mathbf{EF_{NG}}$ = Emission factor for natural gas combustion in combustion turbine (g/mmBtu)
$\mathbf{E_K}$ = KMMEF Combustion emissions and process CO_2 by carbon balance (kg/tonne)
V_f = Fugitive methanol and other hydrocarbons as CO_2
D = Transport distance to Bohai Tianjin China
S_T = Marine vessel and other transport energy intensity (Btu/tonne-mi)
S_{Tb} = Marine vessel energy intensity for backhaul

$\mathbf{EF}_R$ = Emission factor for bunker fuel combustion in engine[29] (g/mmBtu)
$\mathbf{E}_R$ = Upstream life cycle emission rate for residual oil (g/mmBtu)
T_f = Fugitive Emissions that occur in transport as CO_2

S_{NG} represents all of the natural gas to the KMMEF during normal operation. The term $\mathbf{E}_K$ represents the combustion of natural gas in a boiler as well as internally generated fuel gas plus process CO_2. Each of these terms has an emission factor based on the equipment type of design of the methanol production system. Also transport emissions include additional inputs from tugboats and helicopters and are represented as a summation of these terms.

The end use of methanol for MTO results in the same emissions regardless of the source of methanol. The end use comparisons are further discussed in Appendix E.

Alternative Methanol Production

The life cycle of alternative methanol production from coal based methanol in China includes emissions from coal mining, power generation, methanol production and distribution by truck or barge to an MTO facility. GHG emissions are calculated in the same manner as those for KMMEF. Coal to methanol plants include a gasifier that produces synthesis gas, which is further processed as feed to the methanol reactor. A separate stream of coal is fed to a boiler to generate heat. This steam coal may be a lower rank that the gasification coal with a different carbon content (see Appendix C).

For coal-based plants, the life cycle emission rate, $\mathbf{E}_{MCoal}$, can be expressed as:

$$\mathbf{E}_{MCoal} = S_{coal} \times \mathbf{E}_{Coal} + S_{Boiler} \times \mathbf{EF}_{Coal} + S_e \times \mathbf{E}_e + \mathbf{E}_{PCoal} + V_f + D \times (S_T + S_{Tb}) \times (\mathbf{EF}_D + \mathbf{E}_D) + T_f \quad (9)$$

Where:

$\mathbf{E}_{MCoal}$ = Total operational emission rate (kg/tonne methanol)
S_{coal} = Specific energy of coal (kg/tonne methanol)
$\mathbf{E}_{Coal}$ = Upstream life cycle feed + steam coal emission rate (tonne/tonne coal)
S_{Boiler}= Specific energy of coal boiler (Btu/tonne methanol)
$\mathbf{EF}_{Coal}$ = Emission factor for steam coal in a boiler (g/mmBtu coal)
S_e = Specific Energy of electric power (kWh/tonne)
$\mathbf{E}_e$ = Upstream life cycle emission rate for China electric power (g/kWh)
$\mathbf{E}_{PCoal}$ = Coal to methanol vent and process CO_2 emission rate (kg/tonne)
V_f = Fugitive methanol emission rate as CO_2
D = Transport distance to Bohai Tianjin China
S_T = Truck transport energy intensity (Btu/tonne-mi)
S_{Tb} = Truck transport energy intensity for backhaul

[29] A very small fraction of the fuel use for transport includes helicopter fuel and diesel for tugboats in addition to bunker fuel.

$\mathbf{EF_D}$ = Emission factor for diesel in truck engines (g/mmBtu)
$\mathbf{E_D}$ = Upstream life cycle emission rate for diesel fuel (g/mmBtu)
T_f = Fugitive emissions that occur in transport as CO_2

A.3. Fugitive Emissions and Loss Factor

Fugitive emissions and losses contribute to overall GHG emissions due to their secondary formation of CO_2 in the atmosphere. In addition, product losses require additional energy inputs and emissions in the life cycle.

Fugitive emissions from methanol production facilities include methanol vapors and other light hydrocarbons that escape from storage tank vents as well as methanol vapors that are lost during the transfer of methanol from storage tanks to transport vessels or trucks and back to storage tanks. The KMMEF will implement controls of fugitive vapors that return these components to storage tanks. Unloading methanol also results in fugitive emissions. The functional unit for this Study is methanol delivered to Bohai Tianjin, which includes the fugitive losses from methanol transfers. These emissions represent a small contribution towards overall life cycle emissions but are examined because they are part of the GREET modeling framework and are included in the life cycle of other inputs for methanol production. The analysis here also shows the magnitude of fugitive emissions.

Table A.1 shows fugitive emissions from methanol transported from KMMEF to China as well as from other locations to China. As discussed in the next section, VOC emissions are calculated as fully oxidized CO_2 and included in the total GHG emission quantification. Controlled fugitive emissions, V_f, correspond to:

$$V_f = V_o \times (1 - CF) \times VD \qquad (10)$$

Where:

V_f = Fugitive emissions from methanol transfer
V_o = Volume of methanol transferred
CF = Control factor
VD = Vapor density

Vapors in the marine vessel or truck tank are in equilibrium after hauling the methanol to Bohai Tianjin China as well as the return trip because some methanol remains in the tank. Vapors are readily captured and recovered with a water scrubbing system. Since the unloading facility in China has not been specifically identified, the unloading is calculated with no vapor recovery. Vapor emissions from the tanker filling and loading at the KMMEF are consistent with the FEIS.

Finally, the total fugitive emissions are combined to determine a loss factor (1 + loss/total product) that allows for the calculation of life cycle emissions per tonne of methanol delivered to an MTO facility.

In addition to methanol vapor, fugitive emission can include other hydrocarbons such as DME as well as small amounts of CO_2 and CH_4. These emissions were estimated in the FEIS and are included with the total fugitive emissions.

Table A.1. Fugitive Emissions from Methanol Storage and Transport

Source	Emission Controls	Emissions (kg/tonne)			
		VOC as CO_2	**CO_2**	**CH_4**	**CO_2e**
KMMEF [a]	-	-	-		
Methanol Storage [b]	Vapor Balance	0.00007	0.0017	0.00013	0.005
Tanker Ship Fill	Vapor Balance		Included above		
Tanker Ship Unload	None	0.03	0		0.035
China					
Methanol Storage	None	0.001	0.010	0.001	0.036
Truck Fill	None	0.03	0		0.035
Truck Unload	None	0.03	0		0.035
Methanol Pathway		Loss Factor [c]			
KMMEF Marine		1.00003			0.040
Other Marine		1.00006			0.106
China Truck		1.00006			0.106

[a] VOC emissions in the FEIS correspond to 0.18 tonne of VOC per year from tank scrubber. Since methanol would be the largest component, fully oxidized VOC is calculated from the molecular weight ratio such that fugitive emissions = $0.18 / 3,600 \times 44/32 = 0.00007$ kg/tonne

[b] Methanol storage emissions for KMMEF EIS with 99% control efficiency. Uncontrolled fugitives calculated from vapor density of 1.7 lb/1000 gal of vapor space or 0.26 kg/tonne or methanol that is displaced.

[c] Loss factor based on 1 + fugitive methanol/methanol product add VOC column

A.4. Sensitivity Analysis

Inputs for sensitivity analysis are shown in Table A.2. The effect of each parameter and the cumulative effect is presented in Section 6.2

Table A.2. Inputs for Sensitivity Analysis and Scenarios

Parameter	Baseline	Lower	Upper	Market Mediated
Methanol Delivery	100,000 tonne	50,000 tonne	100,000 tonne	100,000 tonne
NG Upstream	94.6 % BC	100% BC	North America	94.6% BC
Market Effects	none	none	none	Appendix F.2
Power Generation Mix	WA	Renewable	eGRID	Marginal
Coal Use Rate	2.2 t/t	2.31 t/t	2.09 t/t	2.2 t/t
GWP of CH_4	AR4	AR5	AR4	AR4
Coal Upstream	China Average	China, w.Coal Power	GREET	China Average
Scenario	Combination of scenario inputs except for GWP values			

A.5. Cut Off Criteria

Minor inputs and emissions that have a small effect on life cycle GHG emissions were excluded from the Study. The Study team selected a cut off level of relevance of 1% of the KMMEF emissions, which is less than the variability in most LCA studies on similar products. Table A.3 describes the assumptions underlying those choices regarding the activities that were identified but excluded from the Study. In many cases the alternative use of methanol would include similar activities. The exclusion of these activities is consistent with the ISO 14040 standards (Section 5.2.3).

Table A.3. Assumptions for Exclusion of Activities from the Analysis

Parameter	Activity Estimate	Cut-off Basis
KMMEF Decomissioning	Remove facility and recycle materials.	Decomissioning emissions would be lower than construction since no materials would be required. Recycled materials would generate co-product credit. Construction emissions excluding materials are less than 0.3% of annual emissions.
Employee Commute	Less than 100 employees	< 0.1% of annual emissions
Employee Air Travel	Less than 20 trip/ year	< 0.1% of annual emissions
Catalyst	Replace 500 tonnes every 4 years	< 0.1% of annual emissions
Sulfur co-product	0.002 tonne/tonne coal methanol.	Co-product credit would be less than 0.1% of KMMEF GHG emissions.
Limestone for coal facility emission control.	0.005 tonne/tonne coal methanol.	Production and transport emissions would be less than 0.1% of KMMEF annual emissions.
Water movement	KMMEF uses locally available water. Coal methanol requires various water sources.	Water pumping for KMMEF is less than 0.1% of total GHG emissions and less than that for coal based methanol.

A.6. Greenhouse Gases and Global Warming Potential

The greenhouse effect is due to concentrations of gases in the atmosphere that trap heat as infrared radiation is reradiated back to outer space. The phenomena of natural and human-caused effects on the atmosphere that cause changes in long-term meteorological patterns due to global warming and other factors is generally referred to as climate change. Natural sources of GHGs include biological and geological sources such as forest fires, volcanoes, decomposition of animal and plant matter, and respiration of living organisms. However, industrial sources of GHGs are the primary concern. GHGs are usually quantified in terms of CO_2 equivalent (CO_2e)

because CO_2 is the most abundant of these gases with the highest cumulative warming effect. The relative longevity in the atmosphere combined with the heat trapping effect determine the global warming potential (GWP). The IPCC has examined a range of global warming potential GWP values since the first assessment report was published in 1990.

The atmospheric lifetime of a species measures the time required to restore equilibrium following a sudden increase or decrease in its concentration in the atmosphere. Individual atoms or molecules may be lost or deposited to sinks such as the soil, the oceans and other waters, or vegetation and other biological systems, reducing the excess to background concentrations. The average time taken to achieve this is the mean lifetime.

Carbon dioxide has a variable atmospheric lifetime of about 30 to over 100 years. This figure accounts for CO_2 molecules being removed from the atmosphere by mixing into the ocean, photosynthesis, and other processes. However, this excludes the balancing fluxes of CO_2 into the atmosphere from the geological reservoirs, which have slower characteristic rates. Although more than half of the CO_2 emitted is removed from the atmosphere within a century, some fraction (about 20%) of emitted CO_2 remains in the atmosphere for many thousands of years. Similar issues apply to other greenhouse gases, many of which have longer mean lifetimes than CO_2. e.g., N_2O has a mean atmospheric lifetime of 121 years (Myhre et al., 2013).

Figure A.1 shows the components of radiative forcing in the atmosphere. The largest contributor to warming is CO_2, which depends on its radiation absorbing characteristics as well as the concentration in the atmosphere. The next most prominent heat trapping gas is methane. Its heat trapping effect is about half that of CO_2 and the lifetime of methane in the atmosphere is much shorter. Each of the greenhouse gases also result in secondary effects. For example, methane dissociates to form CO_2. It also has a role in ozone formation in the atmosphere.

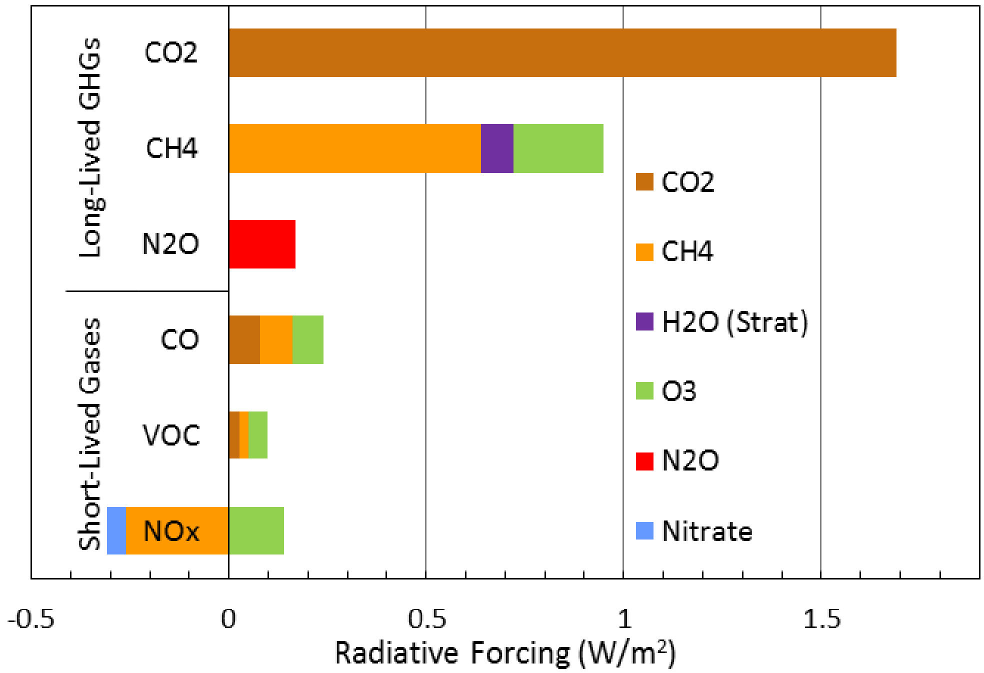

Figure A.1. Components of Radiative Forcing for Principal Emissions.
Source: (Myhre et al., 2013)

The absolute global warming potential (AGWP) of greenhouse gases is shown in Figure A.2. This figure shows the cumulative heat trapping effect of different gases over a time horizon. The yellow and blue curves show how the AGWPs increase with time horizon. Because of the integrative nature the AGWP for CH_4 (yellow curve) reaches its primary effect after two decades as CH_4 is removed from the atmosphere. The AGWP for CO_2 continues to increase for centuries. The ratio of the CH_4 to CO_2 AGWP is the GWP for CH_4 (black curve), which drops with increasing time horizon as the relative importance of CO_2 is reflected with its longer atmospheric lifetime. The AGWP values are from the IPCC AR5; so, the GWP values of 86 at 20 years and 30 at 100 years correspond to the values on the black curve. Note that after20 years about 80% of the effect of CH_4 has occurred while CO_2 continues to contribute to heat absorption for 100s of years.

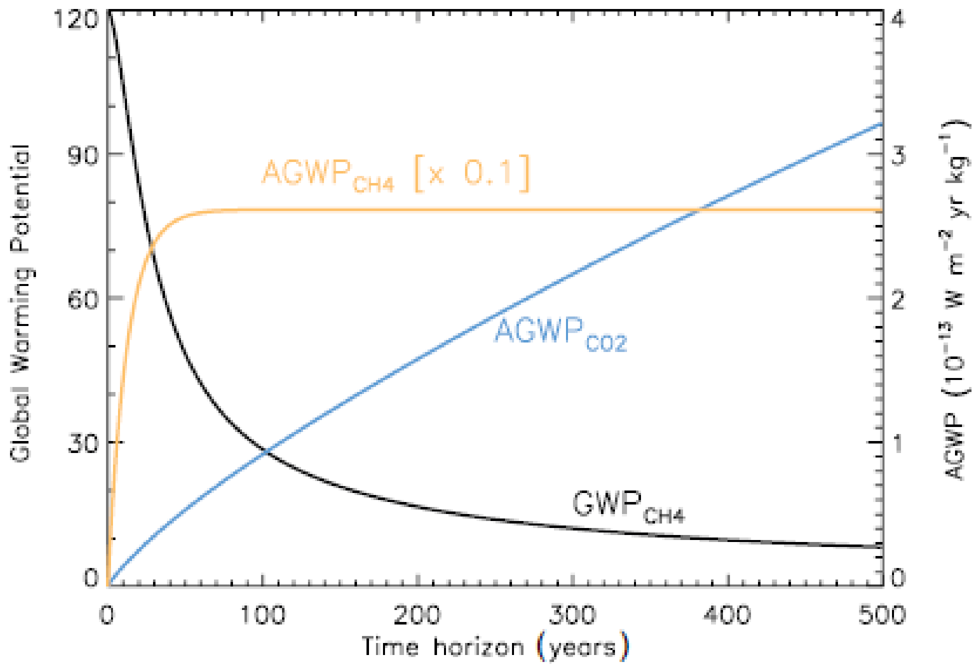

Figure A.2. Development of AGWP-CO_2, AGWP-CH_4 and GWP-CH_4 with time horizon.
Source: (Myhre et al., 2013)

Time Horizon

Estimating the GHG impact of a change in new technology requires understanding of three characteristic time periods (O'Hare et al., 2009). The first of these is the analytic horizon, the period over which consequences are 'counted' in analysis. This may be one hundred years or more. The second is the production period, the time during which the production facility is expected to displace an alternative product. The third important period runs from the present to a policy target date. Methanol from the KMMEF would fall into the longer category of time horizons of interest since the facility has an expected life over 40 years and climate stabilization goals aim to achieve equilibrium over multiple decades. As such use of a twenty-year GWP overstates the impact of short-lived GHGs and understates the impact of long-lived GHGs. This Study uses 100-year GWP values; which is consistent with GHG reporting protocols for the EPA and State of Washington.

B. Appendix B. Upstream Life Cycle Emissions

Energy and material inputs for methanol production also result in indirect or upstream life cycle emissions. The upstream life cycle contribution are the emissions associated with producing and transporting the feedstock and fuel to the point of use. This Appendix describes the inputs and upstream life cycle GHG emissions associated with feedstocks to produce and distribute methanol including natural gas, electric power, coal, and petroleum fuels.

B.1. Natural Gas

The upstream life cycle emissions for natural gas include extraction, processing, transport and distribution. The energy inputs and GHG emissions are modeled via these steps in the GREET and GHGenius models.

B.1.1. Natural Gas Extraction, Processing, and Transmission

Natural gas extraction involves the operation of compressors and separation equipment at the wellhead and gas processing facilities. GHG emissions are calculated based on the energy inputs from aggregate data which are inputs to the GHGenius and GREET models. The models calculate the life cycle emissions including the upstream emissions to produce fuels for gas extraction and processing.

Table B.1 shows the energy inputs for natural gas production and processing as well as the mix of shale gas and conventional gas as GREET inputs. The recovery efficiency and processing efficiency[30] are converted to Btu/mmBtu of natural gas in the GREET model as indicated in the table. As can be seen, the process fuels used for recovery and processing are mainly natural gas with small amounts of diesel, gasoline, residual oil, and electricity. The upstream life cycle emissions resulting from process fuel use is also accounted for recursively in the model. This includes the upstream emissions associated with electricity production, petroleum recovery and refining, as well as natural gas recovery and processing emissions (the upstream emissions of the upstream emissions). The GREET analysis includes flared natural gas as well as fugitive methane and CO_2 which are discussed in more detail below.

[30] The GREET model efficiency inputs which are represented as efficiencies and fuel shares are derived from statistics on energy use.

Table B.1. GREET 1_2017 Default Inputs for Conventional Gas Production.

	NG Recovery		NG Processing	
Energy Inputs	**Fuel Shares**	**Btu/mmBtu**	**Fuel Shares**	**Btu/mmBtu**
Total		25,641		26,694
Residual oil	1%	256		
Diesel fuel	11%	2,821	1%	267
Gasoline	1%	256		
Natural gas fuel	86%	22,051	96%	25,626
Natural gas flared	--	9,940		
Electricity	1%	256	3%	801
Fugitive Emissions (g/mmBtu), LHV				
CH_4		135.4		6.8
CO_2				776

[a] Efficiency combined with fuel shares determines energy input per mmBtu of natural gas such that 1,000,000 × (1/efficiency-1) × fuel shares = energy input for each fuel. Fuel Shares represent the amount of energy resource consumed during the production, transportation, processing, and distribution of a transportation fuel.

Note that the GREET default values in Table B.1 reflect the allocation of emissions between natural gas and natural gas liquids[31].

Although Table B.1 provides the GREET default assumptions for conventional NG recovery, the calculation to convert process efficiency to fuel consumption is the same for shale gas recovery. Table B.2 provides the GREET assumptions regarding the relative shares of conventional and shale gas production as well as their corresponding recovery and processing efficiencies. Note that the energy inputs (and therefore emissions) for conventional gas and shale gas production are very similar. The GREET projection for growth in shale gas is less than that shown in Figure 2.8 of the Study. However, since the energy inputs for conventional and shale gas are essentially the same as the GREET defaults utilized in this Study, this would not materially impact the results.

[31] The original GREET documentation shows the relationship between energy inputs for the natural gas industry and the allocation of the inputs to natural gas and natural gas liquids on an energy basis. Subsequent updates to GREET presumably followed this approach. Studies on leaks from natural gas systems generally do not allocate emissions to natural gas liquids. From EIA in 2015 Dry Natural Gas production 27,065 bcf (EIA, 2018b). 289.5 bcf vented and flared Natural Gas liquids as NG 1817 bcf with allocation factor of 93.7% to natural gas. Note that flared natural gas is consistent with GREET energy input in Table B.1 ($289.5/27065 \times 10^6 \times 93.7\%$) = 10,025 Btu/mmBtu.

Table B.2. GREET1_2017 Inputs for North American NG Recovery and Processing

Year	NG Supply from Shale	Recovery Efficiency[a]		Processing Efficiency	
		Conventional	Shale	Conventional	Shale
2016	51.5%	97.5%	97.6%	97.4%	97.4%
2020	53.6%	97.5%	97.6%	97.4%	97.4%
2040	55.2%	97.5%	97.6%	97.4%	97.4%

[a] The extraction and recovery efficiency is the GREET input to represent fuel used per mmBtu of gas extracted or processed. The GREET model converts the efficiency input to Btu/mmBtu. A fraction of the energy corresponds to natural gas, electric power and diesel fuel (Fuel Shares). In the case of natural gas recovery and processing most of the fuel is either raw gas from the well or pipeline gas.

The GREET model also calculates energy inputs and emissions from compressors used for natural gas transport. The GREET values provide the basis for natural gas transmission.

B.1.2. Fugitive Methane Emissions

Fugitive emissions from natural gas production correspond to a significant share of the upstream GHG emissions from natural gas. In response to increased natural gas production and recognizing the significant uncertainty associated with fugitive methane emissions measurement, this subject has received intense investigation in recent years. The Environmental Defense Fund (EDF) recently commissioned a suite of studies to try to better quantify natural gas industry methane emissions. The EDF sponsored reports include one for gas field emissions (Allen et al., 2013), and another for gathering and processing emissions (Marchese et al., 2015), a report by (Zimmerle et al., 2015) on methane emissions in transmission, and another (Lamb et al., 2015) on distribution emissions. To compare the emission estimates, ANL divided the emission estimates in these reports by EIA estimated total withdrawals to arrive at an emission rate normalized to gas throughput. The EPA cites these studies as references for methane fugitive emissions in the most recent (2016) national emission inventory.

A recent study by Stanford University, University of Calgary, and the Carnegie Endowment (Brandt et al., 2017)examined natural gas production from the Seven Generations (7G) Energy operations and proposed plans to ship LNG to China[32]. The project team had direct access to leak data. The study evaluated various methods for measuring methane leaks and related the results to natural gas production rate. The Stanford team also evaluated the effect of improved maintenance.

Figure B.1 shows leak rate versus throughput for gas production pads that were examined in this project. In general, pads have lower leak rates than conventional single wells. The largest pads result in the lowest leak rate. Even though small pads have higher leak rates, their

[32] The route is functionally similar to that of the KMMEF with natural gas produced in Canada, processed on the west coast, and shipped to China.

contribution to a weighted average leak rate is not significant. Brandt cites a 0.18% loss compared with the average EPA inventory of 0.86% for natural gas extraction activities.

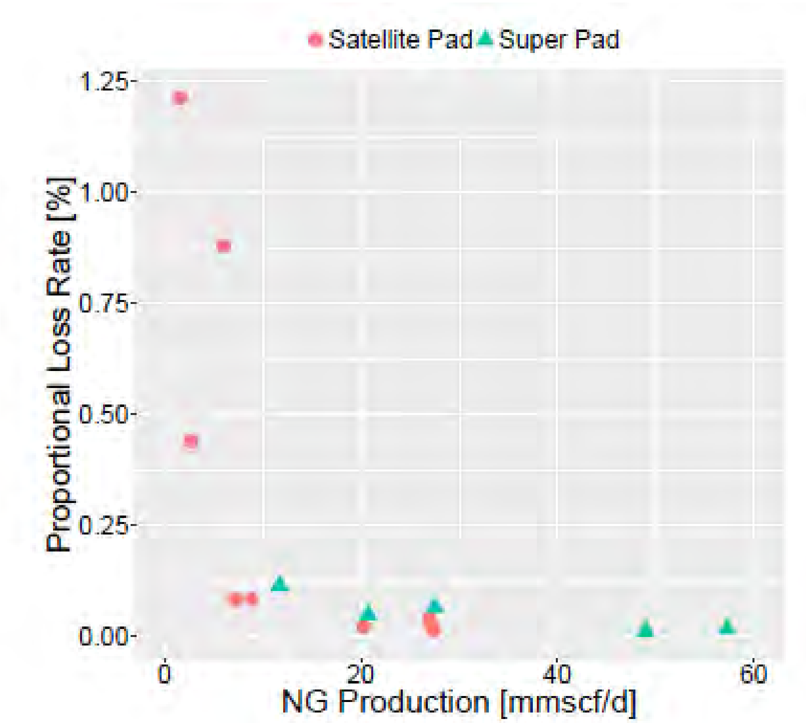

Figure B.1. Leak rate as a function of natural gas production from G7 study.

The analysis of leak maintenance from the 7G project is shown in Figure B.2. Emission reduction occurs with better management practices and potentially Canadian requirements on emission controls.

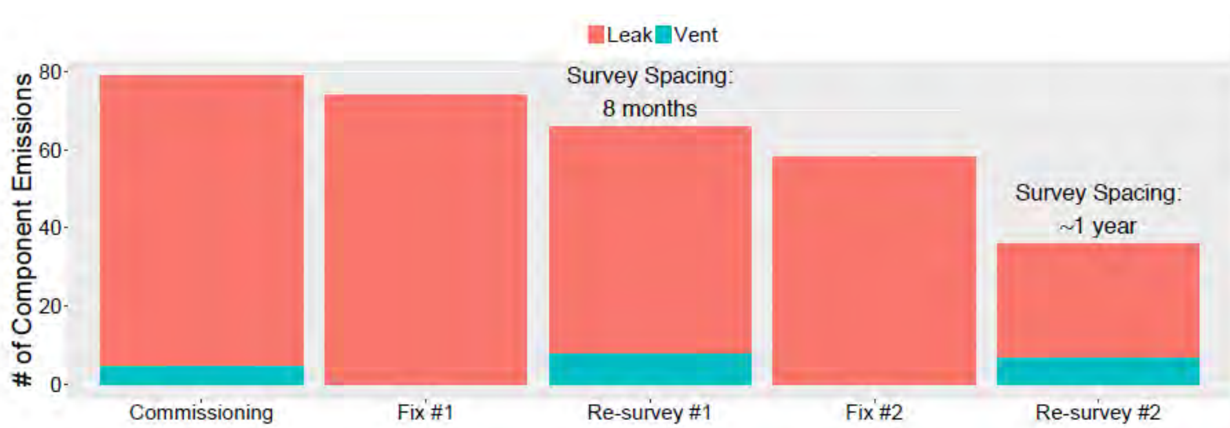

Figure B.2. The G7 study shows the effect of maintenance on methane leaks.

The previously mentioned ANL papers on quantifying fugitive methane emissions provide comparisons between the EPA GHGI values divided by throughput, the GREET model values and the aggregated values from the EDF studies. Table B.3 summarizes these estimates. The EPA estimate for gas field emissions more than doubled between 2015 and 2016; the GREET value followed suit and is slightly lower for the 2017 version of the model (based on 2015 year data), but slightly higher than the EDF study composite[33] .

Table B.3. Summary of Recent Upstream Natural Gas Leakage Estimates (% of gas delivered)

Activity	Type	Gas Field	Processing	Transmission	Distribution	Total
GREET1_2015	Shale	0.34%	0.13%	0.41%	0.43%	1.30%
	Conv	0.30%				1.26%
GREET1_2016	Shale	0.77%	0.13%	0.36%	0.14%	1.38%
	Conv	0.70%				1.32%
GREET1_2017*	Shale	0.67%	0.03%	0.22%	0.08%	1.00%
	Conv	0.66%				0.99%
EPA GHGI 2013 data[a]	U.S.	0.31%	0.15%	0.36%	0.22%	1.04%
EPA GHGI 2014 data [a]	U.S.	0.68%	0.15%	0.20%	0.07%	1.11%
Allen, 2013 [b]		0.38%	n/a	n/a	n/a	
EDF Studies 2015 [c]		0.58%	0.09%	0.25%	0.07%	0.99%
(Tong, Jaramillo, & Azevedo, 2015) [d]		0.49%	0.04%	0.46%	0.31%	1.30%
GHGenius 2016, BC	BC	0.18%	0.003%	0.014%	0.13%	0.32%
BC 2017	BC	0.26%	0.1%	0.03%	0.01%	0.4%
G7 study (Brandt et al., 2017)	BC	0.18%	n/a	n/a	n/a	n/a
(Alvarez et al., 2018)	U.S.	1.8%	0.13%	0.32%	0.08%	2.3%

[*] The extraction and transmission fugitives are 143.6 and 44.7 g CH_4/mmBtu respectively. GREET model identifies the distribution but does not utilize it since industrial and commercial NG users are upstream of the local distribution.

[a] Reported in EPA 2015, @ Reported in EPA 2016

[b] Taken from ANL "Updates to CH_4 Emissions with Natural Gas Pathways in GREET1_2015" Table 5 – ANL divided reported methane emission values by EIA gross withdrawals.

[c] The Gas Field value utilizes EPA's value for gas field emissions (0.31%) and Marchese's value for gathering (0.27%). The processing value is a combination of EPA's value for routine maintenance and (Marchese et al., 2015)'s processing value. Transmission is from (Zimmerle et al., 2015).; Distribution is from (Lamb et al., 2015)

[d] Gas field estimate also includes road construction, well drilling, and fracking emissions

The current GREET estimate for processing emissions has decreased sharply based on EPA's 2017 estimates of reduced emissions from reciprocating engines and centrifugal compressors. Transmission and distribution emissions in GREET1_2017 are similar to those from the EDF studies. For this Study, the GHGenius inputs and GREET inputs span the range of GHG emissions. Distribution emissions are excluded from the estimate, since KMMEF is not connected to a distribution system and will be served with a new transmission lateral.

[33] Which is the EPA gas field value plus Marchese's gathering emissions.

Fugitive methane emissions from the natural gas delivery chain are material to the project's Life Cycle GHG emissions. The methane leak (i.e. fugitive emissions) assumptions in the GREET model reflect the most recent emissions published by the EPA in the national emission inventory as quantified by ANL (Burnham, 2016, 2017; Burnham, Han, Elgowainy, & Wang, 2015).

Recent studies e.g., (Heath, Warner, Steinberg, & Brandt, 2015; Lamb et al., 2015; Peischl et al., 2016; Zimmerle et al., 2015) have reported a range in methane emissions from natural gas that compare to the U.S.GHG inventory (GHGI).

It is worth noting that fugitive gas emissions are significantly different from jurisdiction to jurisdiction due to both geophysical considerations and regulatory regimes. As Ravinder and Brandt note, "Measurements in the Bakken Shale in North Dakota have demonstrated emission rates over 10% while recent data from the Marcellus shale show emission rates lower than 1%."(Ravikumar & Brandt, 2018).

Emission inventories and the corresponding representation in LCA models show that the upstream life cycle GHG emissions from natural gas in British Columbia and Canada as a whole are lower than the reported United States averages. The GHGenius model estimates BC GHG emissions of 0.32% of production vs estimates of U.S. emissions from 1.0% to 1.5%, or higher (see Table B.3). Similarly average U.S. emissions are about 12 CO_2e/MJ (GREET result in following Section) vs Natural Resources Canada estimates of Canadian emissions of 7 to 8 CO_2e/MJ (ICF Consulting CANADA, 2012). The Suzuki Foundation notes that, "According to the B.C. Ministry of the Environment (2012), total fugitive methane emissions from the oil and natural gas industry were about 78,000 tonnes (2.1 million metric tonnes CO_2e). According to the report, B.C. produced 41 billion cubic meters (or 30,757,689 tonnes) of gas in 2012. That would suggest that only about 0.28 per cent of the gas produced was released into the atmosphere"(Werring, 2018).

Brandt et al. measured emissions from Canadian company Seven Generations Energy, at .18% (Wellhead only) which also corresponds to the GHGenius figure. Finally, newer wells have distinctly lower emissions than older wells, and pads and "super pads" (the drilling of multiple wells from a single site which is now common practice) have distinctly lower emissions (see Figure B.1). This is common practice in BC.

The BC government maintains that, "B.C. [is] home to Best Practices" when it comes to regulations regarding hydraulic fracturing and fugitive emissions (Ministry of Natural Gas Development, 2017).These regulations include;

- Through regulation BC has effectively eliminated the use of routine flaring, "Methane emissions are currently lower in BC than many jurisdictions as the province requires natural gas to be conserved where possible instead of flared and vented, which limits the amount of methane emitted."

- Operators in BC are required to have fugitive gas management plans. Monitoring and controlling leakage is part of the plan.
- The Federal government has released draft legislation, which with the support of the provinces would introduce control measures that reduce emissions to by 40 to 45% by 2025 relative to the 2012 level.

Figure B.3 demonstrates BC's low and falling GHG intensity. The results in kg/m3 of natural gas correspond to 6000 g CO_2e/mmBtu, HHV

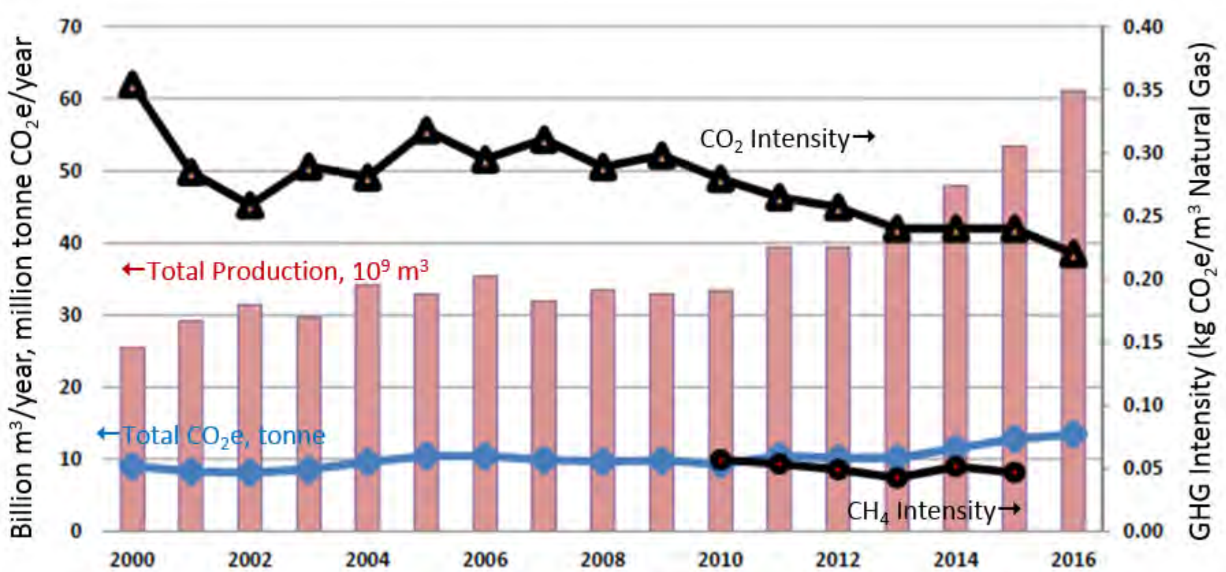

Figure B.3. British Columbia Natural Gas Production and GHG Emissions.
Source: (Province of British Columbia, 2018)

Noting that two recent papers (Atherton et al., 2017; Werring, 2018) by Atherton and Werring have questioned the BC governments estimate of wellhead fugitive emissions and suggested that they could be from 1.5 to 2.5 times higher, that would still result in overall emissions below the US rates (i.e. 1.0% to 1.5%, or 2.3% from Stanford, Table B3). To this point Atherton notes in his 2017 paper that, "our results suggest that natural gas activity in the Montney formation may emit both less frequently and less severely than U.S. comparators."

The KMMEF will use the existing transmission system without any addition of pipeline capacity other than a new 3.1-mile 24-inch lateral. It is important to note that adding gas volume to the existing transmission system should not affect fugitive losses of methane because these fugitive emissions are not generally a function of the volume of gas in the system since leaks are more related to the fittings and connections than the pipeline throughput. As a result, when system volumes go up and the leak rate stays static, the ratio of leaks per volume decreases. However, to be conservative, such a reduction has not been incorporated into this Study.

B.1.3. GHG Emissions from Natural Gas Production

Life cycle GHG emissions from the GHGenius model were obtained for the British Columbia scenario for the year 2020. The model presents GHG emissions as CO2e and the sub detail for CH_4 and N_2O were obtained by entering a GWP of zero for CH4 and N2O sequentially in order to determine CH_4 and N_2O separately as shown in Table B.4.

Table B.4. GHGenius life cycle emissions for British Columbia natural gas (g/mmBtu, HHV)

Model Result	GHGenius Results for CNG			Emissions for NG Feed		
Pollutant	CO2e	CO2+CH4	CO2+N2O	**CO2**	**CH4**	**N2O**
Fuel ------>	**CNG**	**CNG**	**CNG**	**CNG**	**CNG**	**CNG**
Feedstock ------>	**NG**	**NG**	**NG**	**NG**	**NG**	**NG**
Fuel dispensing	0					
Fuel distribution and storage	1,131	1,129	1,080	1,077	2	0
Fuel production	2,344	2,333	2,111	2,100	9	0
Feedstock transmission	0	0	0	0		
Feedstock recovery	2,675	2,645	2,109	2,080	23	0
Feedstock upgrading	0	0	0	0		
Land-use changes, cultivation*	0	0	0	0		
Fertilizer manufacture	0	0	0	0		
Gas leaks and flares**	2,610	2,610	2	2	104	0
CO2, H2S removed from NG^	994	994	994	994		
Emissions displaced	0	0	0	0		
Total	9,755	9,711	6,296	6,253	34	0.14

Source: GHGenius 4.3a, CNG result pasted in from model, British Columbia natural gas, year 2020.
Pipeline gas upstream emissions correspond to CNG without fuel dispensing.
Results for each individual pollutant, CO_2, CH_4 and N_2O, are calculated by setting GWP values to zero for example $CH_4 = CO_2+CH_4 - CO_2$, etc.

The GREET assumptions for conventional natural gas for recovery and processing energy use and methane leakage data are consistent with the emissions associated with delivering feedstock to the KMMEF. Table B.5 provides the resulting GHG estimate for natural gas produced conventionally and from tight gas formations.

Table B.5. GREET1_2017 Natural Gas Upstream Emissions

g/MMBtu	Conventional				Shale					Trans &	Total		
	NA NG Recovery	Recovery Leakage	NG NG Processing	Processing Leakage	NA NG Recovery	Recovery Leakage	NG NG Processing	Processing Leakage	Trans & Stor	stor leakage	Conv	Shale	Blend
VOC	1.9		4.6		1.8		4.6		3.9		10.4	10.3	10.3
CO	10.0		2.5		9.5		2.5		19.9		32.4	31.9	32.1
NOx	13.9		3.2		13.2		3.2		23.6		40.7	40.0	40.3
PM10	0.3		0.1		0.3		0.1		0.1		0.5	0.5	0.5
PM2.5	0.3		0.1		0.3		0.1		0.05		0.5	0.4	0.4
SOx	0.6		10.6		0.5		10.6		0.5		11.7	11.6	11.7
BC	0.1		0.02		0.1		0.02		0.01		0.2	0.1	0.2
OC	0.1		0.1		0.1		0.1		0.02		0.2	0.2	0.2
CH4	8.9	135.7	4.4	6.8	8.5	137.7	4.4	6.8	19.6	44.7	220.2	221.8	221.0
N2O	0.02		0.01		0.02		0.01		1.4		1.4	1.4	1.4
CO2	2,342.4		1,830.9	777.5	2,247.6		2,605.9		1,787.4		6,738.2	6,640.9	6,688.1
CO2 (w/VOC & CO)	2,363.9		1,849.3	777.5	2,268.1		2,624.2		1,830.8		6,821.5	6,723.1	6,770.8
GHGs	2,592.8	3,393.6	1,963.1	948.3	2,487.4	3,443.4	2,739.1	170.8	2,734.8	1,117.5	12,750.1	12,692.9	12,720.6
GHGs,g/MJ	2.5	3.2	1.9	0.9	2.4	3.3	2.6	0.2	2.6	1.1	12.1	12.0	12.1

Assuming AR4 100-year GWP values (25 & 298)

The department of Energy's Energy Information Agency (EIA) tracks the interstate gas flows within the Unites States. These data shown the annual receipts and deliveries from adjacent states and from Canada as indicated in Table B.6. Gas moving to Washington comes predominantly from BC and Idaho, and occasionally from Oregon, through Idaho from the U.S. Rocky Mountain region. Natural gas may be scheduled from U.S. Rocky Mountain sources, but such natural gas does not typically get physically delivered into Washington (as detailed in Table B.6.)

Table B.6. Natural Gas Receipts and Deliveries to Washington

	million cubic feet/year		
	Washington	**Idaho[a]**	**Oregon**
Receipts			
BC	440,984	728,183	
Washington	0	9,927	768,479
Oregon		93,141	
Idaho	711,640	--	0
Nevada[b]			220,307
Utah		6,989	
Wyoming		109	
California			
Deliveries			
BC	6,908	0	
Washington	0	9,927	0
Oregon	768,479	737986	
Idaho	9,927		93,141
California	0		680,979
Nevada			
Net			
BC	434,076	728,183	
Washington		-701,713	768,479
Oregon	-768,479	93,141	
Idaho	701,713		-93,141
Nevada		-26,331	220,307
California			-680,979
Utah			

Source: (EIA, 2018a).

[a] Gas delivered from Idaho to Washington comes from a pipeline interconnect in BC from pipelines coming out of both BC and Alberta. Idaho has produced a minor amount of natural gas in recent years, but such natural gas is delivered and used locally in Idaho.

[b] Gas delivered from Nevada to Oregon originates in the U.S. Rocky Mountains and connects to a natural gas market hub (Malin) on the California/Oregon border; the Nevada natural gas moves directly in to California.

Table B.7. Natural Gas Receipts

	To Washington	
	MM CF/y	**Fraction**
Net Receipts to WA	-	
From BC/WA Border	434,076	38.0%
From Idaho via BC Border	701,713	61.4%
From U.S. Rocky Mtn	6,870	0.6%
Total	1,142,659	
Net Deliveries to OR	768,479	
WA Net Gas Balance	374,180	

B.2. Power Generation

One key input for life cycle GHG quantification is the resource mix used to generate electricity that is purchased by the plant. While the KMMEF will generate a portion of its electricity demand on-site, 864 GWh of electricity will be purchased each year[34]. There are a several different resource mixes that could be used for the electricity purchased by the KMMEF and they are discussed below. A key question is whether to use an average mix or the resources that come online to service the new demand (marginal mix).

Average Mix

The KMMEF is located in Cowlitz County and will procure electricity from the regional power market for subsequent delivery to the KMMEF by the Bonneville Power Administration (BPA) and Cowlitz County Public Utility District (Cowlitz PUD). Regional power consists of dozens of federal hydroelectric plants, the Columbia Nuclear Generating Station (publicly owned), various wind facilities as well as natural gas and coal-fired plants.

Washington State publishes the Electric Utility Fuel Mix Disclosure Report (State Energy Office at the Washington Department Of Commerce, 2017) each year, summarizing the statewide and utility level (e.g. Cowlitz PUD) retail power sales by fuel type. In addition to state and local resource mixes, the U.S. EPA manages the eGRID database which catalogs electricity generation data for a number of electricity generating regions. The KMMEF is located within the Northwest Power Pool (NWPP) region shown in Figure B.4.

[34] 240 kWh/tonne methanol * 3.6 million tonnes methanol * 10^6 tonnes/million tonnes/10^6 GWh/kWh

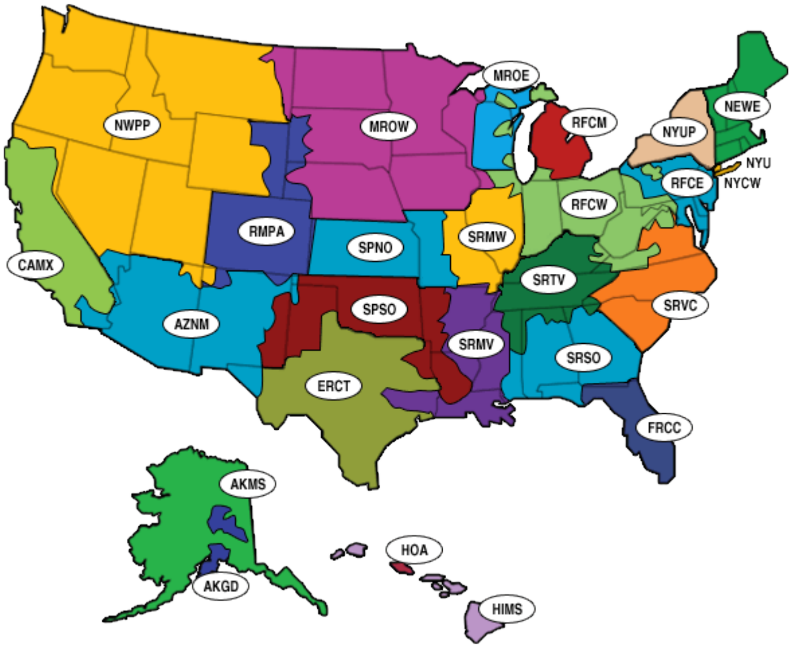

Figure B.4. Map of eGRID Subregions

Resource mix data for Cowlitz PUD and Washington State in 2016 are summarized in Table B.8. Also shown are the 2014 and 2016 eGRID data for the NWPP region. The Cowlitz PUD mix results in very low GHG emissions per kWh since it predominately consists of hydro and nuclear power. The Washington state average mix for 2016 has more fossil generation and less hydro than the Cowlitz mix. The NWPP mix is higher carbon due to its larger share of coal generation. Note that between 2014 and 2016 coal generation in the NWPP decreased significantly while hydro, renewables and natural gas generation all increased.

Table B.8. Applicable Electric Power Generation Resource Mixes

Resource	2016 Washington Average	2014 NWPP eGRID[35]	2016 NWPP eGRID[36]	2016 Cowlitz PUD
Residual oil	0.1%	0.2%	0.2%	0.0%
Natural gas	11.5%	11.9%	15.3%	2.2%
Coal	14.1%	36.2%	22.5%	3.0%
Nuclear	4.9%	2.8%	3.4%	9.7%
Biomass, LFG	1.1%	1.1%	1.3%	4.6%
Hydroelectric	64.0%	40.0%	47.2%	77.2%
Geothermal, Wind, Solar	4.2%	8.0%	9.7%	3.2%
Others	0.1%	0.0%	0.4%	0.1%

[35] eGRID2014v2 Generation Resource Mix

[36] (US EPA, 2016)

In general, the most representative grid mix to utilize to quantify life cycle GHG impact is the local grid mix. However, because of its size, Cowlitz PUD is unable to procure sufficient power for the KMMEF. Therefore, the next most representative average mix is the Washington state average mix. The NWPP mix is for a much larger geographic region (~ seven states) so is less representative of the electricity delivered to the KMMEF. It is LCA's opinion that the most accurate average grid mix to use in this analysis is the 2016 Washington state average grid mix from the Fuel Mix Disclosure report.

Marginal Mix

One question that might be raised regarding electricity emission estimates is whether an average grid mix or a marginal grid mix should be utilized. Specifically, which new resources will come online to meet the new load? As mentioned above, the new load from the KMMEF is 864 GWh annually. There are three trends that must be considered when determining the makeup of the marginal mix for the KMMEF. First, electric power consumption in Washington state decreased by 4,400 GWh in 2016 from its peak in 2014 (Figure B.5). Moreover, the Northwest Power and Conservation Council's 7th plan (Northwest Power and Conservation Council, 2016) asserts that all load growth forecast for the next 20 years can be met by cost effective conservation. Given the load growth anticipated for the KMMEF is 20% of the recent decrease between 2014 and 2016, one approach is to simply assume the growth is met by conservation.

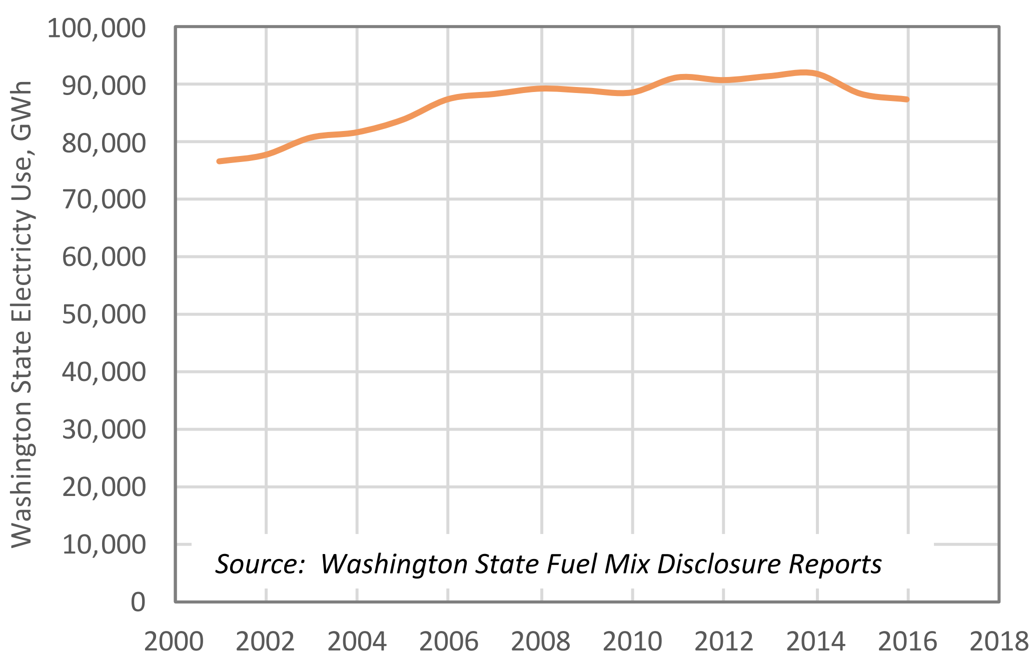

Figure B.5. Washington State electricity consumption.

The second trend that must be considered is the decline in the coal fleet. Table B.9 provides the coal fired units within the NW Power and Conservation Council's territory (Idaho, Montana, Washington, Oregon). As indicated, the two remaining coal plants in Washington State will both retire by 2025 so 61% of the region's coal generating capacity will have retired by 2025. Note that even though Washington's two coal plants will have retired by 2025, utilities will still import coal generated electricity from other states as needed.

Table B.9. Regional Coal Plant Retirement Dates

Coal Fired Boiler	State	MW	Retirement
Colstrip Energy LP	MT	46	
Colstrip Unit 1	MT	360	2022
Colstrip Unit 2	MT	360	2022
Colstrip Unit 3	MT	780	
Colstrip Unit 4	MT	780	
Lewis & Clark	MT	50	
Hardin Gen Project	MT	116	
Boardman	OR	642	2021
Centralia 1	WA	730	2020
Centralia 2	WA	730	2025
	Total Coal	4,594	
	Total Retiring	2,822	

The third trend to consider is the Washington State Energy Independence Act of 2006 which establishes a renewable portfolio standard (RPS) of 15% new renewables (hydro plants existing before 1999 do not count) by 2020 and each year after.

From Figure B.5 we see that Washington State consumed 87,374 GWh of electricity in 2016. If the decrease in consumption continues, by 2020 total in-state consumption will decrease to approximately 80,384 GWh. The RPS requires that 15% of this must be renewable for a total of 12,000 GWh of renewables. This represents an increase of more than 7,400 GWh of renewables. Since the KMMEF demand represents less than 12% of the new renewables that must come online by 2020 to meet the RPS, one could argue that an appropriate marginal mix could be 100% renewables.

Another approach for specifying a marginal mix is provided in Table B.10. A generation mix for 2020 is defined by setting the hydro to an average of the most recent five years and all other resources to the 2016 level except coal and renewables. The renewables are set to 15% of total to comply with the RPS. The total generation is maintained at the 2016 level and the coal generation is reduced to accommodate the increase in renewables. For 2040 the same assumptions are made except coal is reduced to zero with natural gas making up the difference. Next, it is assumed that hydro and nuclear resources will be base loaded units while all other resources will compete on the market and therefore are marginal. For 2020 the marginal mix is 6% coal, 41% natural gas and 53% renewables. For 2040, the marginal mix is 46% natural gas and 53% renewables. Assuming a 40-year project life with 15 years at the 2020 mix and 25 years at the 2040 mix, the marginal mix for the project life is 2% coal, 44% natural gas and 53% renewables.

Table B.10. Washington Department of Commerce Electric Power Forecast and Marginal Mix

	2020			2040			Project Life		
	Mix	**Marginal**	**%**	**Mix**	**Marginal**	**%**	**Mix**	**Marginal**	**%**
Hydro	58,408	0	0	58,408	0		58,408		
Nuclear	4,308	0	0	4,308	0		4,308		
Coal	1,384	1,384	6%	0	0		519	519	2%
Petroleum	114	114	0%	114	114	0%	114	114	0%
Natural Gas	10,055	10,055	41%	11,439	11,439	46%	10,920	10,920	44%
Renewable	13,106	13,106	53%	13,106	13,106	53%	13,106	13,106	53%
Total	**87,374**	**24,659**	**100%**	**87,374**	**24,659**		**87,374**	**24,659**	

Source: WA Department of Commerce

Given the uncertainty and complexity of calculating a marginal grid electricity mix, use of an average grid mix can be more appealing. Moreover, there is considerable precedence for using an average resource grid mix. For example, CalEEMod, the model utilized in California to quantify project emissions for CEQA purposes (California's version of the Washington State Environmental Policy Act) stipulates that to quantify GHG emissions for electricity consumption, the emission factors for the local utility should be used. The Washington State Agency GHG Calculator tool[37] utilizes electricity emission factors from the State Fuel Mix Disclosure Report. Finally, the California Air Resources Board chose an average mix for quantification of electric vehicle carbon intensity values for use in their Low Carbon Fuel Standard.

The assorted resource mixes considered in this Study are summarized in Table B.11. The corresponding GHG emissions from the GREET model with these mixes is provided in Table B.12. The Washington state average is approximately 60 g/MJ, the current NWPP eGRID value is 90 g CO_2e/MJ and the estimated marginal mix is 71 g CO_2e /MJ.

[37] The tool may be downloaded at https://ecology.wa.gov/Regulations-Permits/Reporting-requirements/Climate-change-emissions-reporting/State-agency-reports-tools

Table B.11. Resource Mixes Evaluated

Fuel	2016 WA State Average	2016 NWPP eGRID	Renewable	WA State Marginal
Residual oil	0.1%	0.2%	0%	0%
Natural gas	11.5%	15.3%	0%	44%
Coal	14.1%	22.5%	0%	2%
Nuclear	4.9%	3.4%	0%	0%
Biomass	0.9%	1.3%	0%	1%
Other (Renewable)	68.5%	57.3%	100%	52%

Table B.12 shows the life cycle GHG emissions for various resource mixes. The Cowlitz PUD mix had the lowest GHG intensity but the Washington state average was use for the baseline analysis as a conservative assumption. The eGRID GHG intensity has dropped significantly due to the decommissioning of coal power plants, which is reflected in the marginal analysis also.

Table B.12. GREET Life Cycle GHG emissions for Various Electricity Resource Mixes

	g/MMBtu				gCO₂e/MJ
	CO_2	CH_4	N_2O	CO_2c	GHG[a]
2016 WA State Avg	59,684	112	1	59,751	59.6
2016 Cowlitz PUD	13,413	31	1	13,537	13.9
2014 NWPP eGRID	127,042	213	2	127,141	126.2
2016 NWPP eGRID	90,369	166	2	90,466	90.2
Marginal 100% Renewable	975	2	0	1,004	1.1
Marginal 2020	75,652	197	1	75,784	76.9
Marginal 2040	66,521	196	1	66,660	68.1
Marginal Project Life	69,945	196	1	70,082	71

[a] AR4 100-yr GWP factors

China Electricity Grid

An electricity resource mix is also needed to calculate GHG emissions in China. Table B.13 provides the 2020 electricity grid mix considered for China (China Automotive Energy Research Center of Tsinghua University, 2013)

Although the electricity resource mix is little diversified based on the research, however there is a low chance for current and future new methanol plants to use non coal based power. The reason is that non-coal based power is limited and the generated far away from the methanol plants, so even without an electricity grid in place for coal-based methanol plant the only source for power is coal.

According to national statistics for China, in 2017, thermal power (coal-based) accounted for 73%, hydropower accounted for 18%, others accounted for 9% , which is in between the range of data in Table B.13.

Table B.13. Resource Mixes for China Power.

Fuel	China Average	Inner Mongolia
Residual oil	0.9%	0%
Natural gas	4.0%	0%
Coal	54.0%	90%
Nuclear	6.2%	0%
Biomass	1.3%	0%
Other (Renewable)	33.6%	10%

Source: (ASIACHEM, 2018; China Automotive Energy Research Center of Tsinghua University, 2013; Jiang et al., 2013)

There are considerable variations in the grid mix from province to province and in general the methanol plants are located in areas where the power generation is generally coal fired. However, it is more conservative to use the average China grid mix as a basis for power generation in this Study.

B.3. Coal Production

Coal mining and transport emission were examined from a range of sources to generate a range of estimates for the upstream life cycle emissions of coal delivered to a coal to methanol plant.

Estimates of the energy inputs for coal production are shown in Table B.14. These data are presented per mmBtu of coal, which are the input units for the GREET model. Data from IEA and several other studies provide data for the energy inputs for coal mining emissions in China. The IEA data are generally consistent with the GREET data for the U.S. and provide the lower estimate for coal mining in China. Two other sources indicate higher energy inputs for China coal production (ASIACHEM, 2018; Jiang et al., 2013). These show that 2.5% to 3.5% of the coal is consumed in the mining process, which may correspond to coal mine fires (Rennie, 2002). Estimates of the high range of coal mining emissions are based on the lower estimates from a China LCA study (Jiang et al., 2013).

Coal Mine Methane (CMM)

Coal mine methane (CMM) represents a significant source of GHG emissions in China (International Energy Agency, 2009; US EPA, 2011). CMM refers to methane released from the coal and surrounding rock strata due to mining activities. In underground mines, methane can create an explosive hazard to coal miners, so it is removed through ventilation systems. In some instances, it is necessary to supplement the ventilation with a degasification system consisting of a network of boreholes and gas pipelines. In abandoned mines and surface mines, methane might also escape to the atmosphere through natural fissures or other diffuse sources. Estimates of CMM from China vary from 0.03 to over 0.1 tonne CH_4/tonne coal. Capturing methane for use as an energy source remains challenging; so, CMM represents about 50% of the GWP weighted GHG emissions associated with coal production.

Several sources of coal mine methane were examined. IEA estimated close to 170 million tonnes of CMM emissions from China in 2015 (International Energy Agency, 2009). The annual coal production data for the same year was taken from the EIA statistics (U.S. Energy Information Administration, 2018). The ratio corresponds to about 80 g CH_4/mmBtu of coal. GREET model includes the distinct methane emission rates for underground and surface mining. As referenced in (Zhang & Chen, 2010), about 95% of the coal mines in china are underground mines and only 5% are surface mines. When the GREET emissions rates were weighted by the ratio of underground to surface mining specific to China, GREET results in 344 g CH_4/mmBtu of coal. The GREET default value of 145.5 g/mmBtu of coal is between the high and low range of CMM emissions[38]; so, this value was unchanged in estimating the upstream emissions for coal production.

Table B.14 summarizes data on the energy inputs for coal production. The baseline case is based on the China average energy inputs. Inputs for the Upper scenario correspond the GREET default

Table B.14. GREET Inputs for Coal Production

Source	This Study[a]		ASIACHEM	Jiang	GREET
Coal Production Input	**Baseline**	**Upper**	**China[b]**	**China[b]**	**U.S. Average[c]**
Energy Inputs (Btu/mmBtu), HHV					
Residual oil	0	493	1,716	0	493
Diesel	937	3,948[d]	0	937	3,948
Gasoline	312	211	0	312	211
Natural Gas	312	70	0	312	70
Coal	24,602	634	26,000	24,602	634
Electric Power	4,374	1,692[d]	4,978	4,374	1,692
Fugitive CH_4 (g/mmBtu)	228.9	145.5	228.9		145.5

[a] Low range for China based on IEA diesel and electric power plus GREET defaults for other fuels. High range corresponds to data from (Jiang et al., 2013) with CMM reported by Asia Chem.
[b] Estimates of China coal production appear to include coal lost due to coal mine fires
[c] GREET default value used for upstream life cycle emissions associated with the coal fraction of power generation
[d] Emissions from a study on coal export to China (ICF International, 2017b) Table 8 indicated 1,069 Btu/mmBtu diesel and 2,050 Btu/mmBtu of electric power with 0.3 tonne CH_4/tonne of coal.

[38] The CMM emissions as per GREET is 0.078 tons CO_2e per ton of coal produced. This closely matches the corresponding value of 0.085 from the 2018 ASIACHEM survey (ASIACHEM, 2018). However, the ASIACHEM survey also adds fugitive CO_2 emissions equivalent to 0.012 tons/tons coal which are not included in GREET and this study.

B.4. Petroleum Upstream Life Cycle

Upstream life cycle GHG emissions for petroleum fuels including diesel, LPG, bunker fuel, gasoline, and naphtha were calculated based on the regional resource mix for Washington and China.

B.4.1. Petroleum Fuels Consumed in China

China is a rapidly growing economy with high demand for refined products. Upstream emissions for China petroleum products were based on:

- Location of crude oil imports to China
- China average electricity mix
- Energy inputs for China coal extraction (Jiang et al., 2013)

B.4.2. Petroleum Fuels Consumed in Washington

There are five refineries in Washington State[39] with a combined refining capacity of over 230 million barrels per year. Although the state is a net exporter of refined product, gasoline and diesel are imported from Montana and Utah into eastern Washington. The most recent available pipeline transfer data[40] indicate that 6% of diesel consumed in Washington is refined in Montana and transported to Washington via the Yellowstone pipeline and 10% is refined in Utah and transported via the Tesoro pipeline. The balance (84% of diesel) is assumed to be refined in Washington State. We assume that all residual oil/marine diesel consumed is refined in-state.

[39] British Petroleum Cherry Point, Shell Oil Anacortes, Tesoro Anacortes, Phillips 66 Ferndale, and US Oil Tacoma.

[40] 2013 data provided by Hedia Adelman, Washington State Department of Ecology

C. APPENDIX C DIRECT COMBUSTION EMISSIONS

Direct combustion emissions occur from a variety of sources in the life cycle. These emissions include CO_2, CH_4 and N_2O which depend on the carbon content and heating value of the fuel and the combustion characteristics of the boiler, engine, or other applications. CO_2 emissions for fuel combustion depend upon the carbon content, density, and heating value of fuels such that all of these properties are consistent. In this LCA, emission factors are identified in the units based on the original data source including the higher heating value (HHV) or lower heating value (LHV) basis. Table C.1 shows the calculation of the carbon factor (g CO_2/mmBtu) for the primary fuels in the life cycle of methanol and alternative sources of methanol. The carbon factor is calculated such that the carbon per Btu is multiplied by the molecular weight ratio of CO_2 to carbon such that:

$$\text{Carbon factor} = \text{wt\%C/HHV (Btu/lb)} \times 453.59\ \text{g/lb} \times 44/12.01 \times 10^6 \qquad (11)$$

Table C.1. Calculation of CO_2 Emission Factors from Fuel Properties

Fuel	Natural Gas	Residual Oil	Diesel	Coal[a]	Sub-bituminous Coal	Feed Coal	Lignite
Carbon (wt%)	74.2%	86.8%	86.5%	63.7%	53.7%	59.3%	48.4%
Higher Heating Value							
(Btu/lb)	23,180	18,148	19,676	10,304	8,725	10,576	8,236
(Btu/unit)	1,049	150,110	137,380	22,716,827	19,234,385	23,314,869	18,156,060
Unit	scf	gal	gal	tonne	tonne	tonne	tonne
Carbon Factor							
(g CO_2/mmBtu)	53,223	79,478	73,049	102,722	102,275	93,174	97,615
(kg CO_2/kg)	2.72	3.18	3.17	2.33	1.97	2.17	1.77
Source:	NW-IW	GREET	GREET	GREET	GREET	ASIACHEM	ASIACHEM

[a] GREET value used to calculate emissions from power plants and other processes using coal.

Note that the heating value of coal ranges from 8,000 to 12,000 Btu/lb, HHV depending upon the coal rank and properties. However, the carbon factor of coal expressed per mmBtu falls into a relatively narrow range of 93 to 104 CO_2/mmBtu (EPA, 2014) since heating value and carbon content are interrelated.

Hydrocarbon and carbon monoxide emissions are treated as fully oxidized CO_2 under most GHG accounting systems including IPCC AR4 (IPCC, 2007) and Argonne's GREET model (ANL, 2017b). In the IPCC assessment, for example, the GWP of carbon monoxide is considered to be 1.5 to 2 which is consistent with the fully oxidized treatment of CO (ratio of 44/28 = 1.57) which is the value used in the GREET model.[41] State of Washington SEPA (WAC 197) identifies emission AP-

[41] When fuel use is represented as an emission factor per MMBtu of fuel, this factor typically includes all of the carbon in the fuel. However, emission factors for individual types of equipment such as marine engines might

42 as an appropriate source of emission factors. More specific data are also acceptable for GHG reporting. Emission factors for each energy source in the Study are based either on actual fuel properties, emission factors for CH_4 and N_2O used in the FEIS, or GREET emission factors. Note that fuel combustion occurs through the upstream fuel cycle for all of the energy inputs associated with the project and displaced emissions. Therefore, calculations based on the GREET direct emission factors are more consistent than mixing data from various sources. Table C.2 shows the fully oxidized CO_2 emissions as well as CH_4 and N_2O emissions from various combustion sources in this Study.

Table C.2. Direct Combustion Emissions

Fuel/ Application	Equipment Type	CO_2c	CH_4	N_2O	CO_2e
WTT Emissions (g/mmBtu), HHV		-	-	-	-
Diesel	Diesel Engine	74,890	4.0	0.6	75,146
Diesel	HD Truck	74,889	4.5	0.2	75,035
Gasoline Blending Component	Gasoline Engine	71,629	2.8	0.6	71,854
Gasoline E10	Gasoline Engine	66,503	2.8	0.6	66,878
LPG	LPG Engine	63,252	3.3	1.0	63,627
Bunker Fuel	Marine Engine	79,540	1.4	1.6	80,047
Natural Gas	IC Engine	53,094	354.3	0.1	60,563
Natural Gas	Turbine, CC	53,222	1.0	0.1	53,276
Natural Gas	Boiler	53,222	1.0	0.7	53,444
Coal	Boiler	94,885	1.0	1.5	95,354

[a] Fuel on the FuelSpecs sheet in GREET1_2017

[b] Calculated from Cowlitz natural gas composition with GREET emission factors for CH_4 and N_2O.

GREET model is characterized by its recursive calculations with a large but limited initial inputs. The model uses those inputs to calculate the emission rates for multiple interdependent fuels or commodities. For example, grid electricity is used in processing natural gas, implying the dependence of the natural gas emission rate on the given electricity grid's emission rate. The electricity grid itself may use natural gas, thus leading to the recursive nature of the model. In the following sections we present some of the independent inputs used in the model along with the final emissions from natural gas, electricity and coal under different input scenarios.

include separate values for CO_2 and CO emissions. To be consistent with IPCC and SEPA reporting protocols, CO should be counted as fully oxidized CO_2. The effect of this detail is typically less than 0.5% of CO_2 emissions from any source. This study includes VOC and CO emissions as CO_2c because these emissions are counted in the GREET LCA framework. Also, many emission inventory methods show CO_2 as fully oxidized carbon in fuel.

D. Appendix D. Methanol Data

D.1. Methanol Technology

Table D.1 shows a range of natural gas reforming technology available to be used in the methanol production process and compares them with the specific design used in the KMMEF which utilizes the ULE technology with a mix of import and self-generated power.

Table D.1. Inputs for Natural Gas-Based Methanol Production

	MMBtu/tonne methanol, HHV			Power	MeOH/Feed Efficiency	
Type	**Feed**	**Steam**	**Total**	**kWh/tonne**	**HHV**	**LHV**
NG SMR	32.5 – 34.5	0.5	33.5 to 35.5	--	63.8%	62.0%
NG SMR CO_2 Addition	32	0.5	32.5	--	66.7%	64.9%
Combined Reforming	31.4	0.1	31.5	150	68.9%	67.0%
KMMEF	27.6	2.0	29.6	240	73.2%	71.2%
GREET, 2005/2010	31.2		31.2	--	69.4%	67.5%
GREET, 2020 Technology	29.7		29.7	--	73.0%	71.0%
Kung, SMR	34.9		34.9	--	62.2%	60.5%
Stratton, Autothermal	31.7		31.7	--	68.5%	66.6%
Bechtel, CPO	32.2		32.2	148	68.5%	66.6%
Bechtel, SMR	32.5		32.5	-13	66.7%	64.9%

Sources:

Koempel 28.5 mmBtu/tonne, LHV = 31.5 mmBtu/tonne, LHV which is consistent with California Fuel Methanol Cost Study (Bechtel Inc., 1988) and (National Energy Technology Laboratory, 2014a). GREET default for methanol production is 71% LHV efficiency (31.4 mmBtu/tonne)

NW-IW process design (Confidential)

(Alvarado, 2016). (Zongqin, 2017). Methanol economy, challenges in India (Saraswat, 2016). Methanex (Methanex Corporation, 2012). (Bechtel Inc., 1988) (Lurgi data, generate power from LP steam) (Cheng & Kung, 1994; Mansfield, 1995; McKee, 1988; Sheldon, 2017; Stratton, Hemming, & Teper, 1982)

Table D.2 shows the coal inputs for coal to methanol production from various sources. These include design studies. (Xiuzhang, 2014). An assessment from the China Coal Institute also provides a range of feedstock coal used to make methanol (China Coal Research Institute, 2011).

The coal use rates for facilities greater than 500 ktpa and smaller facilities assumed in this Study are also shown in the table.

Table D.2. Inputs for Coal-Based Methanol Production

Type	MMBtu Coal/tonne methanol, HHV			Methanol/Feed Efficiency		kWh/ tonne
	Feed	Steam	Total	HHV	LHV	Power
Coal Gasification, >500 ktpa	37.3	10.0	47.3	45.9%	42.0%	288
Coal Gasification,<500 ktpa	39.2	11.6	50.8	42.7%	39.1%	288
Koppers-Totzek, 1800 ktpa, Bituminous	37.3	7.0	44.3	48.9%	44.8%	0
GREET			41.2	52.6%	50.0%	0
Entrained Gasifier, 2200 ktpa Lignite	--	--	43.6	49.8%	45.6%	-1030
China Coal Research Institute	--	--	48.2	43% - 48%	41.2%	--
ASIACHEM, 600 ktpa Case 1	39.2	11.6	50.8	42.7%	39.1%	566
Bautou, 600 ktpa Bituminous	36.1	14.0	50.1	43.3%	39.6%	288
ASIACHEM, 1800 ktpa with MTO	40.1	11.7	51.8	41.9%	38.4%	178
China Design Study 1800 ktpa	39.6	10.9	50.5	43.0%	39.4%	150
Lurgi Gasifier, 1800 ktpa, ND lignite	32.8	6.0	38.8	55.9%	51.3%	Export

Table D.3. Inputs for Coal-Based Methanol Production – Mass Basis

Type	Source	Tonne coal/tonne methanol		
		Feedstock	Steam	Total
Coal Gasification, >500 ktpa	Average	1.6	0.55	2.15
Coal Gasification,<500 ktpa	ASIACHEM	1.68	0.64	2.32
Koppers-Totzek, 1800 ktpa, Bituminous	(Reed, 1976)	1.652	0.312	1.96
GREET	(ANL, 2017b)	--	--	1.72
Entrained Gasifier, 2200 ktpa, Lgnite	(Jacobs, 2013)	2.40		2.40
China Coal Research Institute	(CCRI, 2011)	1.42 - 1.59	~0.5	~2
ASIACHEM, 600 ktpa Case 1	ASIACHEM	1.68	0.64	2.32
Bautou, 600 ktpa Bituminous	(HQCEC, 2008)	1.463	0.567	2.03
ASIACHEM, 1800 ktpa w MTO	ASIACHEM	1.72	0.644	2.36
China Design Study 1800 ktpa	(NPCPI, 2012)	1.419	0.487	1.91
Lurgi Gasifier, 1800 ktpa, ND lignite	(Supp, 1990)	1.84	0.34	2.18

Compare with 1.44 tonne feed coal/tonne methanol

https://www.globalsyngas.org/resources/world-gasification-database/huating-zhongxu-methanol-plant

D.1.1. Effect of Methanol as Fuel

Methanol is used as a fuel blending component since it has an attractive volumetric blending price and higher octane number than more energy intense gasoline blending components. Depending on petroleum prices, the amount of methanol blended into gasoline in China is expected to continue to grow. Blending methanol with gasoline results in several energy impacts and emissions effects depending upon the blending strategy. Splash blending is the practice where methanol is added to a pure hydrocarbon gasoline fuel that meets fuel specifications including octane[42]. Refiners may also blend methanol with a sub octane gasoline blending component to achieve the same 87 octane number as conventional gasoline. Oil refiners in the U.S. have implemented this approach for several decades with 10% ethanol using an 84 octane blending component to achieve an 87 octane E10 fuel. The use of ethanol has demonstrated benefits to oil refiners, which results in a lower carbon intensity of gasoline. Refiners operate units such as reformers less severely, which results in higher levels of gasoline product and lower emissions per mmBtu of gasoline (Hirshfeld, Kolb, Anderson, Studzinski, & Frusti, 2014; Mueller, Unnasch, Keesom, Mohan, & Goyal, 2018). In China, the shortage of octane has resulted in the import of high octane blending components from Europe and the U.S (Bousso & George, 2015). Components such as toluene are the products of catalytic reforming and have a higher carbon intensity for both the fuel and the refining portion.

Oil refiners that take into account the octane value of methanol can produce a sub-octane blending component that requires less energy to produce. The reduced refinery energy is estimated to result in a carbon intensity reduction of 1000 g CO_2e/MJ of gasoline.

[42] A Research + Motor weighted octane (R+M)/2 = 87 is typical for regular gasoline.

Table D.4. Comparison of Methanol as a Splash Blend and Octane Enhancer

	M15 Splash Blending			M15 Octane Blending		
Passenger Car Fuel	**Baseline Gasoline**	**KMMEF M15**	**China Coal M15**	**Baseline Gasoline**	**KMMEF M15**	**China Coal M15**
Fuel Economy (mi/gal)	33.9[a]	31.6	31.6	33.9	31.3	31.3
(Btu/mi), LHV	3,429[b]	3,395[c]	3,395	3,429	3,429[b]	3,429
Methanol (M gal)	0	100[d]	100	0	100	100
(tonne)	0	300,600	300,600	0	300,600	300,600
Fuel (M gal)	634.5	666.7[e]	666.7	616.0	666.7	666.7
(GBtu)	72,224[g]	71,509[f]	71,509	71,509[f]	71,509	71,509
Emissions (g CO_2e/mmBtu), LHV						
Vehicle	76,798	76,397	76,397	76,798	76,427	76,427
Upstream M100 Component [h]		31,691	199,713		31,691	199,713
Reduction for Octane Contribution [i]					-595 [j]	
Upstream Fuel	19,833	20,783	34,234	19,833	20,235	33,687
Annual Emissions (M tonne CO_2e/y)[n]				32.2		
Vehicle	5.54	5.46	5.46	5.49	5.46	5.46
Upstream	1.43	1.49	2.45	1.42	1.45	2.41
Total	6.98	6.95	7.91	6.91	6.91	7.87
Difference	0	-0.028	0.93	0	0.002	0.96

[a] 2016 average new passenger fuel economy, 7 L/100 km from transportpolicy.net. Note that the comparisons here do not depend on the gasoline vehicle fuel economy only the relative M15 to gasoline fuel economy.

[b] Energy consumption based on fuel economy and gasoline LHV. Energy consumption is same for E15 with same octane number.

[c] Splash blending of 15% methanol results in an increase in octane number of at least 4 (R+M/2) points (Methanol Institute 2017, blenders) Increasing octane by 10% improves fuel economy by 1 to 3 with 1% improvement show here (Shuai, Wang, Li, Fu, & Xiao, 2013).

[d] GHG emissions are shown for M15 blended with 100 million gallons of methanol

[e] resulting in 666.7 million gallons of M15.

[f] Energy content calculated on LHV basis with same amount of energy displace for octane blending case.

[g] In case of splash blending, fuel economy of M15 increases over conventional gasoline due to higher octane in modern vehicles with knock sensors. Energy use for baseline gasoline in splash blending case is higher.

[h] Upstream emissions for the methanol blending component based on the analysis in Sections 3 and 5.

[i] Refinery energy requirements are reduced with high octane methanol blending component (ANL 2017) with credit assigned to methanol

[j] (Hirshfeld et al., 2014), (Croezen & Kampman, 2009), (Kwasniewski, Blieszner, & Nelson, 2016)

[k] Upstream of conventional gasoline based on China GREET model

[l] Upstream emissions of M15 are calculated from weighted Btu's and upstream emissions for gasoline blending

[m] For octane blending case reduction in gasoline GHG intensity is assigned to methanol

[n] Annual GHG emission are calculated based on energy consumption showing difference between M15 emissions and baseline gasoline.

The weighted carbon intensity and energy consumption are calculated for both the splash blending and octane blending cases. Annual tonnes of GHG emissions are shown for the gasoline baseline and for an M15 fuel based on KMMEF methanol as well as China coal methanol. For both KMMEF cases, the M15 results in comparable GHG emissions compared to the gasoline baseline but the coal based methanol blending case has higher emissions compared to gasoline. The carbon content of methanol per mmBtu is lower than that of gasoline. When combined with the upstream emissions from the KMMEF as well as fuel efficiency effects or effects on gasoline refining, the annual GHG emissions are no higher than those of gasoline fuel. These results are conservative because higher octane components of gasoline such as aromatics and alkylate are the more energy intensive components from oil refineries. Furthermore, the carbon content of aromatics such as toluene are higher than those of conventional gasoline components[43].The higher carbon content combined with a reduced heating value per pound of fuel results in higher GHG emissions from high octane aromatics.

[43] The carbon content of toluene is 91.2% compared with about 86% for average gasoline components.

E. APPENDIX E OLEFIN PRODUCTION

Steam cracking is the predominate method for producing olefins. Petroleum-derived naphtha is a potential feedstock for steam crackers, which produce olefins for a variety of chemical applications. The usage rate for naphtha used in steam cracking differ compared to those for other petroleum derived products. In these instances, more of the petroleum product is required to achieve the same functional unit, olefin. This Appendix compares the petroleum naphtha steam cracking with the more novel olefin production technology of MTO.

E.1. Olefin Production Emissions

Literature describing olefin production process provides the basis to determine the energy inputs and process emissions for MTO and traditional production methods (Dimian & Bildea, 2018; Ren et al., 2004, 2008). Emissions from naphtha steam cracking are based on the net carbon balance and process energy inputs for olefin production (Forman & Unnasch, 2015). The energy and emission data in the study is on the conservative end of the range of reported literature data. We further verified the data by running a carbon balance analysis.

Table E.1 compares the naphtha inputs, other energy inputs, and outputs for steam cracking with petroleum derived naphtha and the MTO process. The carbon balance is consistent with the flow of inputs and returned naphtha streams, combusted coke and fuel gas, and supplemental fuel gas. The direct and upstream emissions for these inputs are assigned to the olefins for each process. In the case of naphtha steam cracking, 100 kg of feed is converted to 49 kg of olefin. Some of the feed is also recycled back to an oil refinery; so, upstream emissions are calculated based on the net feed consumed. In the case of MTO, 2.6 to 3 kg of methanol are converted to 1 kg of olefin; so, 100 kg of feed produces 38 kg of olefin.

Table E.1 Process Conditions for Olefin Productions

Olefin Production	Petroleum Naphtha[a]	MTO[b]
Inputs		
Feed (kg)	100	100
Feed (MJ)	4,494	2,009
Feed (kg C)	84	37.5
Fuel Gas	946.5	0.00
Self-Generated Fuel Gas	846	0.00
Refinery Fuel Gas	100.5	0
Power (MJ)	12.0	8.0[c]
Outputs (kg)		
Ethylene	30.2	16.7
Propylene	15.1	16.7
Butylene	3.8	4.6
Total Olefin	**49.1**	**38.0**
Other Olefin	7.3	1.7
Alkynes	0.7	0
Other Alkanes	2.2	0.2
Heavy Oil	4.0	0
CO_2	3.0	2.3
CO	0.4	0.5
CH_4	15.4	0.0
H_2	0.6	0.0
Coking	2.0	2.0
Backflow to refinery	18.0	0.0
High Value Chemicals	59.3	39.9
Carbon Output	84.0	37.5
Total Output	95.4	43.0

[a] The (Forman & Unnasch, 2015) study investigated the various inputs and outputs for petroleum to olefin conversation.

[b] (Dimian & Bildea, 2018) study presents the entire mass flows and balance for typical MTO process. The yield, inputs and outputs are based on the mass flows benchmarked against (Ren et al., 2008; Tian et al., 2015)

[c] Power per kg of olefin based on (Ren et al., 2004).

The energy inputs and emissions are calculated per 100 kg of initial feed that is used to produce olefins from naphtha steam cracking and MTO process in Table E.2.

Table E.2 Net Inputs and Emissions for Olefin Production

Net Inputs and Outputs	**Petroleum**	**MTO**
Inputs	Naphtha	Methanol
Feed (kg)	82.0	100.0
(MJ), LHV	3,685	2,209
Self-Generated Fuel Gas (MJ)	846.0	0.00
Refinery fuel gas (MJ)	100.5	0.00
Power (MJ)	12.0	7.4
Outputs		
Total Olefin (kg)	49.1	38.04
Miscellaneous products (kg)	10.2	1.88
Heavy Fuel Oil (kg)	4.0	0.00
Pyrolysis Gas (MJ)	443.2	81.73
Heavy Fuel Oil (MJ)	157.9	0.00
Emissions		
Carbon Increase in Pygas and HFO (kg C)	0.15	0.02
Process Emissions (kg CO_2)	53.2	10.3
Refinery Fuel Gas (kg CO_2e)	3.0	0.0

A wide range of yield and GHG estimates are available in the literature. (SINOPEC TECH, 2016) shows a yield close to 2.14 kg olefin/kg naphtha whereas Ren shows a yield in the range of 1.6-1.8 kg/kg. The inclusion of upstream emissions and the carbon intensity of feedstocks is based on specific assumptions for each study; so, comparing the results is challenging. For example, Ren shows 1,375 kg CO_2/kg of olefin for naphtha steam cracking and 1,275 kg CO_2/kg of olefin for MTO. Literature also indicates a large variation in the naphtha to olefin yield. While the total GHG emissions are lower than those in Table E.2, the relative magnitude of MTO and naphtha steam cracking are consistent. Similarly, GHG emissions from oil refinery fluid catalytic crackers range from 630 (Gabi TS) to 852 (GREET, China) kg CO_2e/MJ. However, refinery co-produced olefins will not increase without an expansion in oil refining capacity. Similarly, naphtha steam cracking has the largest share of the olefin market but this feedstock is also tied to the availability and price of petroleum products. Growth in olefin production depends on all of these factors and several sources indicated continued growth in MTO (Alvarado, 2017; ASIACHEM, 2018).

E.2. Downstream Market Effects

Methanol produced from the KMMEF will result in various displacement effects either due to direct competition with alternative methanol or market effects associated with the supply and demand of products. A schematic of the potential displacement effects are shown below. The most significant effects on markets are highlighted in green.

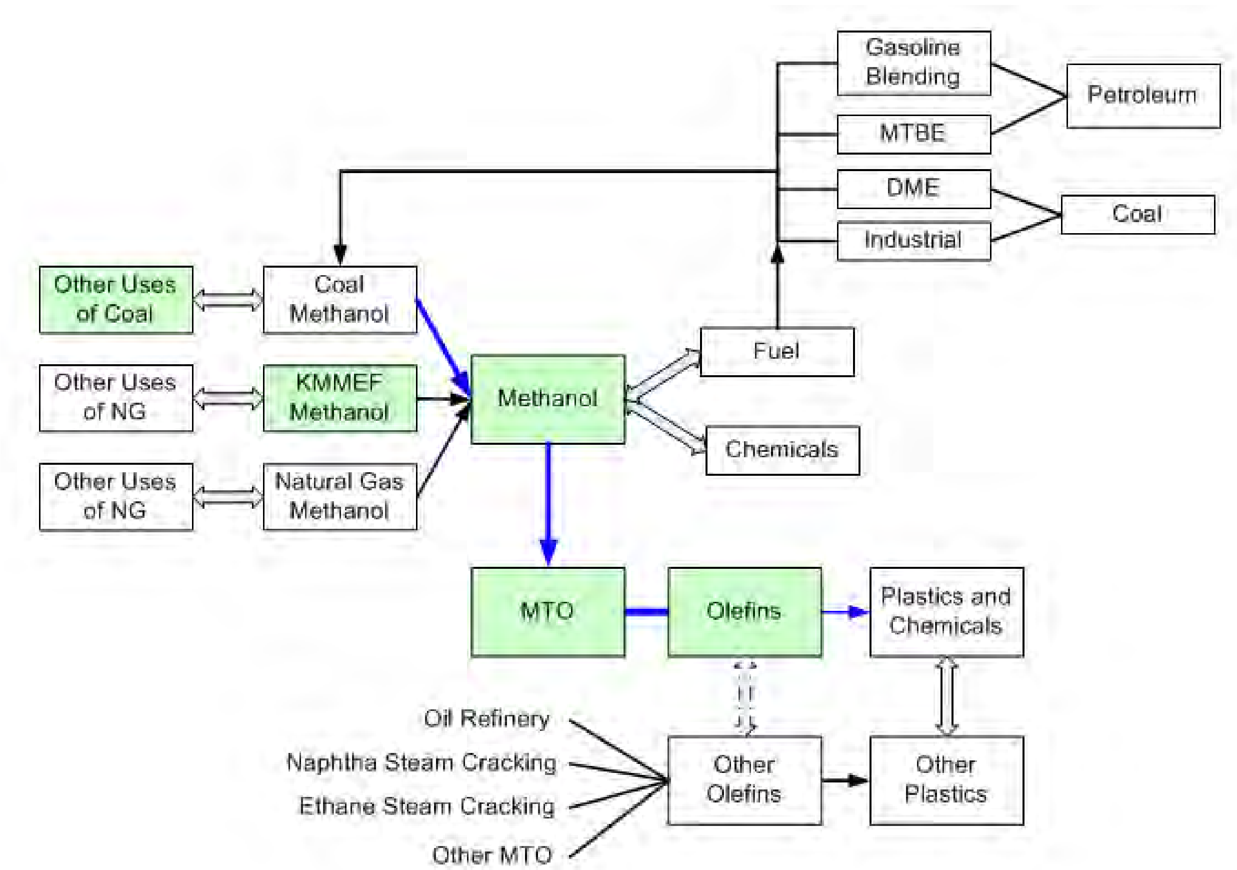

Figure E.1. Market effects of KMMEF methanol on feedstock and olefins markets.

The key displacement effects from KMMEF methanol and related economic effects include the following:

Use of natural gas - Natural gas supplies in British Columbia are plentiful and expanding (BC National Energy Board, 2004) extraction of natural gas for the KMMEF will have a *de minimis* effect on gas prices, which would reduce demand for natural gas and result in other interactions in energy markets. However, the supply of natural gas is so large that the market effect will be small as illustrated by different scenarios for LNG export by the Energy Information Agency (EIA, 2014).

Displacement of alternative methanol – Marginal methanol production is from coal in China (Section 4). Methanol from KMMEF will directly compete with existing over capacity of coal to methanol and new planned coal to methanol capacity (China Coal Research Institute, 2011; ASIACHEM, 2018). China is already a net importer of methanol and coal to methanol plants are at a low fraction of their potential output. Therefore, additional low cost methanol will prevent additional coal to methanol from being deployed.

Displacement of natural gas-based methanol – New natural gas to methanol projects will have the same effect as that of the KMMEF. New projects take a decade to develop; so, any additional competition will be slow to evolve.

Free up coal supply – Displaced coal to methanol will make 7 million tonnes per year of coal available in China. The effects on markets is uncertain given the desire to reduce the use of coal globally. The market effect on coal use, absent policies to reduce coal use is examined in Appendix F.

Compete with other olefins – MTO plants are typically tied to end use customers; so, competition with other sources of olefins may be indirect though the end product such as plastics and other materials. The leading competition for olefins is naphtha steam cracking. The emissions from KMMEF-derived olefins are lower than those from olefins derived from naphtha steam cracking.

Diversion of methanol to fuel and chemicals – Fuel is a growing market for methanol. Methanol from the KMMEF could displace some existing methanol into other markets. The net emission effect corresponds to KMMEF methanol used in these markets. For example, if methanol from KMMEF is sold to an MTO plant and the prior supply of methanol diverts their production to fuel sales, the effect is the same as the KMMEF methanol diverted to this application. Most markets for methanol do not absorb the underutilized production capacity in China (China Coal Institute, 2011); so, any displacement from KMMEF methanol into markets such as fuel or chemicals would be small. Otherwise, China coal-to-methanol plants would be operating at full capacity to sell all of their potential output to fuel markets. For markets such as industrial fuels and DME for cooking, KMMEF methanol would displace coal and result in a significant GHG reduction in those applications. For gasoline blending, KMMEF methanol would result in comparable emissions to petroleum gasoline.

F. Appendix F Energy Prices

Energy prices provide an input to the economic analysis in Section 4 of the Study. Regionally specific energy prices enable the calculation of a supply curve. The following sections describe natural gas, coal, and electric power prices.

F.1. Natural Gas Price

The price of natural gas in regions where gas is plentiful and a limited local market exists (stranded gas) is somewhat difficult to judge. Some sources cite the effective net back prices for LNG production as the local price of natural gas. However, this price of gas is only realized if an LNG plant sells the natural gas. Other markets price the natural gas to ensure it is used so that oil production can continue without being concerned about the use of the associated gas production. This situation generally applies to Middle East methanol producers. In the U.S. local supply and demand affect the price of natural gas. In other regions of the world the price of natural gas is affected by local supply and demand as shown in Table F.1.

Table F.1. Natural Gas Prices

Location	Price $/mmBtu	Source
International		
Saudi Arabia	$1.25	ME Stranded[a]
Oman	$2.00	ME Stranded
Medicine Hat, Canada	$1.80	Methanex
Iran	$2.20	(Azadi, Mahmoudzadeh, & Shirvani, 2017)
KMMEF	$2.80	Natural gas intel
Trinidad	$2.44	energynow.tt
Venezuela	$3.00	(Anouk, 2016)
Chile	$3.50	(Anouk, 2016)
Louisiana	$3.50	Henry Hub + $0.5 Transmission
New Zealand	$4.32	(Concept, 2016)
China		www.315.com.cn
Market Price: East China	$16.18	
Market Price: North China	$13.49	
Market Price: Northeast China	$15.74	
Market Price: Northwest China	$9.79	
Market Price: South China	$17.42	
Market Price: SW China	$13.36	
Market Price: Yangtze River shoreline	$14.59	
Wellhead Price (NW China, Qinghai)	$5.69	
Wellhead Price (NW China, Shaanxi)	$5.97	
Wellhead Price (NW China, Xinjiang)	$5.36	
Wellhead Price (SW China, Sichuan)	$6.64	
West-East NG Transmission	$6.63	
Estimated China Plant Gate	$12.60	

[a] Sources include (Dex Wang, 2015; Reuters, 2013)

F.2. Coal Prices

Coal is the primary feedstock for methanol production in China. Some of the major coal production regions in China are shown in Figure F.1. Major coal production resources are located in Inner Mongolia and Shaanxi. The location of coal resources aligns with the location of methanol production facilities in Section D. China also imports coal from several regions in the world including Australia.

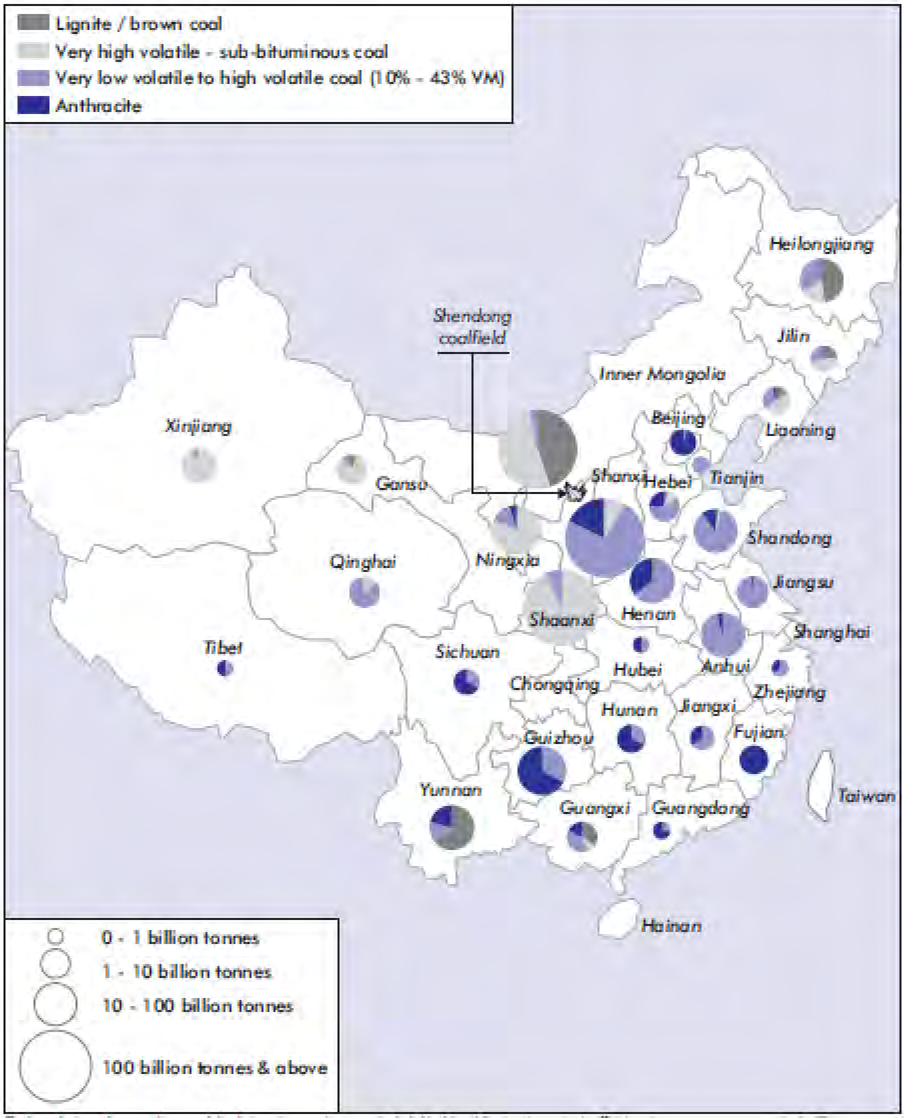

Figure F.1. Location of major coal resources in China.
Source: IEA, 2009

The cost of coal for methanol production affects the marginal cost of methanol. For the analysis in Section 4, the regional cost of coal was assigned to methanol plants in specific regions in China. Methanol plants also use coal for power production this coal is referred to as steam coal and has a lower quality then the feed stock coal.

Table F.2 shows the average price of coal in different regions in China. The average price from this table is consistent with the price of feedstock coal in a study by ASIACHEM for a case study in Northwest China. Since the feedstock prices were in agreement with another study, the data set in Table F.2 was applied to the market analysis in Section 4.

Table F.2. China Coal Prices

China Region	Provinces	$/tonne
East	Anhui, Jiangsu, Shandong, Zhejiang	98.1
North	Hebei, Shanxi, Tianjin	90.3
Northwest	Inner Mongolia, Gansu, Ningxia, Qinghai, Shaanxi, Xinjiang	82.9
	Shaanxi	76.2
Southwest	Chongqing, Guizhou, Sichuan, Yunnan	104.6
Northeast	Heilongjiang, Jilin, Liaoning	95.0
South	Fujian, Hainan	95.0
Central	Henan, Hubei	95.0

Sources: Wind Database and Shaanxi Coal Trade Center
Compare with ASIACHEM, 2018: 505 CNY/6.5 = $77.7/tonne and 466/6.5 = $71.7/tonne

Coal Price Effects
Displacing China methanol will reduce the use of coal feedstock in China. With current policies aimed at reducing coal use, there may be no market response to a reduction in demand from methanol plants or an increase in coal supply (Feng, 2016; New York Times, 2017). However, the coal that is displaced by the KMMEF could have a market effect. The supply curve in Figure F.2 shows the competition between coal imports and China supplies. The displaced coal demand from the KMMEF (3.6 × 2) = 7.2 million tonne/annum would have a 1.2% effect on the price of coal at a demand level of 300 million tonne/annum.

7.2 million tonnes coal × ($83-$79)/(300 -200 M tonne) = $0.3/tonne coal or a 0.36% change in price of coal. The price change combined with an elasticity factor provides an estimate on the change in the coal market such that for a 10% elasticity factor

Induced coal demand = 0.1 × 0.36% × 300 million tonnes of coal = 0.1 million tonnes of coal

0.1 million tonnes of coal × 1.9 tonne CO_2e/tonne of coal / 3.6 tonnes of methanol = 57 kg CO_2e/tonne methanol. This 57 kg CO_2e/tonne methanol would be the induced increase in the emissions if the coal market responds to the price change absent policy to curtail coal use and other factors such as limited power plant capacity.

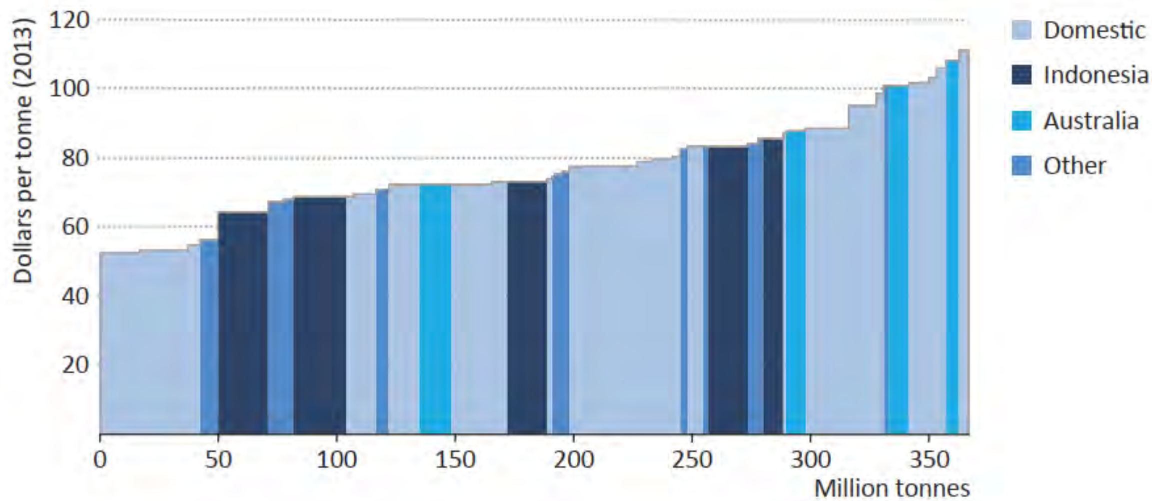

Figure F.2. Supply curve of and cost of steam coal to southern coastal China.
Source: (IEA, 2014)

Additional data on the macro economic effects of coal displacement are found in a study on exporting coal to China. The study includes an extensive dataset on coal markets, mining and its associated emissions (ICF International, 2016, 2017b, 2017a)

F.3. Electricity Prices

Electricity prices vary with region, size of user, utility fees and other factors. The economic analysis in Section 6 applied a power price of \$0.066/kWh for all imported power for Chinese methanol plants (ASIACHEM, 2018, Section 2.1.2). Most natural gas plants using SMR or combined reforming technology are self-sufficient in power production.

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